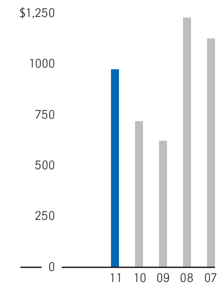
WE ARE A U.S. COMPANY HELPING TO SUPPLY ENERGY FOR ITS COUNTRY.

W&T OFFSHORE

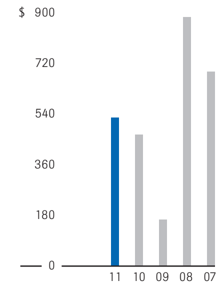
SUMMARY OF SELECTED FINANCIAL DATA

Year Ending December 31	2011	2010	2009	2008	2007
Income Statement					
Total Revenues	$ **971,047**	$ 705,783	$ 610,996	$ 1,215,609	$ 1,113,749
Operating Income (Loss)	$ **329,460**	$ 166,789	$ (219,859)	$ (807,145)	$ 249,249
Net Income (Loss)	$ **172,817**	$ 117,892	$ (187,919)	$ (558,819)	$ 144,300
Cash-Flow Statement					
Operating Activities	$ **521,478**	$ 464,772	$ 156,266	$ 882,496	$ 688,597
Capex (oil and natural gas properties)	$ **719,026**	$ 415,653	$ 276,134	$ 774,879	$ 361,235
Balance Sheet					
Total Assets	$ **1,868,925**	$ 1,424,094	$ 1,326,833	$ 2,056,186	$ 2,812,204
Long-Term Debt	$ **717,000**	$ 450,000	$ 450,000	$ 653,172	$ 654,764
Shareholders' Equity	$ **544,574**	$ 421,743	$ 358,950	$ 572,227	$ 1,151,340
Operating Data					
Net Sales:					
Oil (MMBbls)	**6.1**	5.9	6.1	5.9	6.9
NGLs (MMBbls)	**1.9**	1.2	1.1	1.1	1.4
Natural Gas (Bcf)	**53.7**	44.7	51.6	56.1	76.7
Total Oil Equivalent (MMboe)	**16.9**	14.5	15.8	16.3	21.1
Total Natural Gas Equivalent (Bcfe)	**101.5**	87.0	94.8	97.9	126.5
Average Daily Oil Sales (MMboe/d)	**46.4**	39.7	43.3	44.6	57.8
Average Daily Gas Sales (MMcfe/d)	**278.2**	238.4	259.7	267.5	346.7
Average Realized Sales Price:					
Oil ($/Bbl)	$ **105.92**	$ 77.33	$ 59.96	$ 105.74	$ 71.89
NGLs ($/Bbl)	$ **55.81**	$ 43.65	$ 31.96	$ 60.62	$ 46.45
Natural Gas ($/Mcf)	$ **4.12**	$ 4.55	$ 3.97	$ 9.40	$ 7.20
Oil Equivalent ($/Boe)	$ **57.32**	$ 48.87	$ 38.32	$ 74.50	$ 52.81
Natural Gas Equivalent ($/Mcfe)	$ **9.55**	$ 8.15	$ 6.39	$ 12.42	$ 8.80
Estimated Net Proved Reserves					
Oil (MMBbls)	**51.4**	34.0	31.2	40.0	46.4
NGLs (MMBbls)	**17.1**	4.2	3.0	3.9	4.6
Natural Gas (Bcf)	**289.7**	256.3	165.8	227.9	332.8
Total Oil Equivalent (MMBoe)	**116.9**	80.9	61.8	81.9	106.5
Total Natural Gas Equivalent (Bcfe)	**701.1**	485.4	371.0	491.1	638.8
Total Proved Developed (MMBoe)	**76.4**	65.2	47.3	55.7	65.9
Total Proved Developed (Bcfe)	**458.2**	391.3	283.5	334.1	395.3
Proved Undeveloped (MMBoe)	**40.5**	15.7	14.6	26.2	40.6
Proved Undeveloped (Bcfe)	**242.9**	94.1	87.5	157.0	243.5
Proved Developed Reserves as a % of Proved Reserves	**65.4%**	80.6%	76.4%	68.0%	61.9%

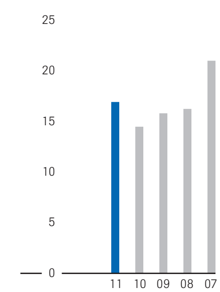
Forward-Looking Statements This Annual Report (including the letter from Tracy W. Krohn, our Chief Executive Officer) contains forward-looking statements within the meaning of the Private Litigation Securities Reform Act of 1995 that involve risks, uncertainties and assumptions. If the risks or uncertainties 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.



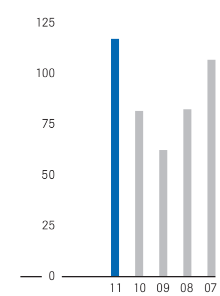
Revenues
(In millions)



Cash Provided by Operating Activities
(In millions)



Production
(MMBoe)



Proved Reserves
(MMBoe)

SHAREHOLDER'S LETTER

2011

Fellow Shareholders,

By any measure, 2011 was an outstanding year for W&T. We are "pumped up" (no need to pardon the obvious pun) about our business, our prospects and our service as a U.S. company providing energy for our country. It's a charge we take very seriously, as reflected in our operational and financial results.

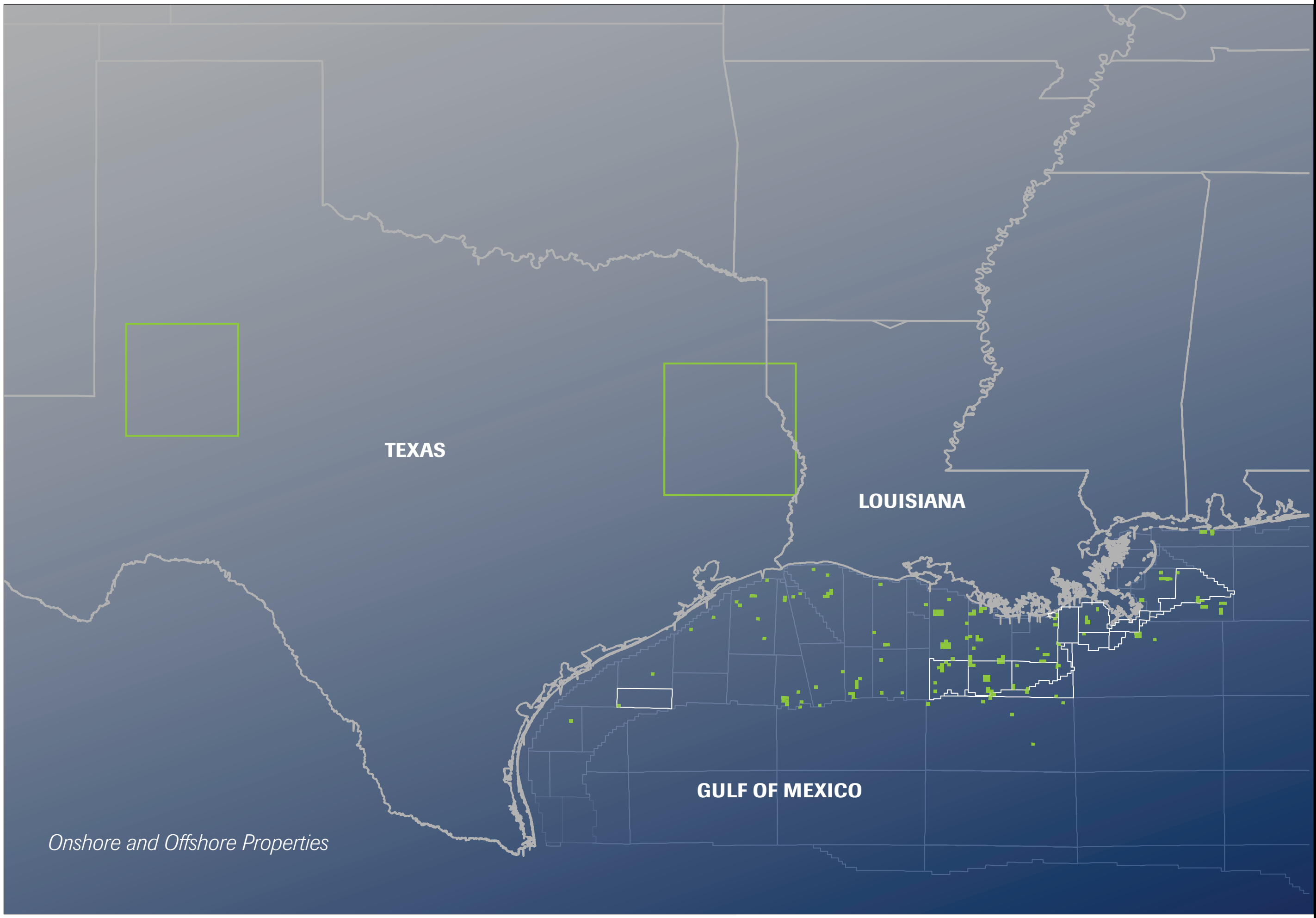
We delivered on our commitment to increase reserves and production, with proved reserves rising 44 percent to 116.9 million barrels of oil equivalent last year and production climbing to 49,800 barrels per day of oil equivalent for the fourth quarter representing a 21 percent increase over the comparable period of 2010. Our reserve replacement ratio for the year was 312 percent and the PV-10 value of our proved reserves grew to $3.1 billion, representing a 63 percent increase over 2010.

We continue to generate significant cash flow. Operating income increased $162.7 million in 2011 to $329.5 million the highest level in the Company's history. Net income rose by $54.9 million to $172.8 million on revenues of $971.0 million. Excluding special items, 2011 net income rose 54 percent to $179.9 million. Earnings per share increased 71 cents to $2.29 (up 81 cents or 52 percent to $2.38, excluding special items). Adjusted EBITDA grew 44 percent to more than $646.5 million. We paid a special dividend to shareholders in 2011 for the fourth time in five years, with a total dividend yield of 3.7 percent. In fact, we recently doubled the size of our quarterly dividend to eight cents per share per quarter from four cents per share previously. For 2011, our total shareholder return, which represents the change in our stock price during the year plus dividends, was approximately 25 percent in a year in which many E&P companies' stock prices were down and the S&P index was flat to slightly negative. This placed us first in a list of 17 peer-group companies.

We improved our liquidity position in 2011, entering into a new four-year revolving credit facility and refinancing our high-yield notes to extend the maturity by five years to 2019. In addition, we increased our borrowing base to $575.0 million from $405.5 million at year-end 2010.

During the year we achieved an all-in reserve replacement cost of $13.59 per barrel of oil equivalent. Even though we have had a consistently high oil component throughout the past five years, at year-end 2011, we are an oilier company with oil and NGLs representing 59 percent of proved reserves. With liquid hydrocarbon prices continuing to outpace natural gas prices, we have continued to focus on crude oil and NGLs. We've also become more diversified, with approximately 173,000 net acres onshore now under our control. The W&T team achieved equally impressive results with the drill bit in 2011, completing a 54-well drilling program, with a success ratio greater than 98 percent.

The Gulf of Mexico, which provides 30 percent of the nation's oil and gas, continues to be the most significant part of our asset base and source of cash flow. Last year's acquisition of the Fairway field off the coast of Alabama and our exploration and development programs offshore provided us profitable opportunities with excellent rates of return and low finding and development costs. We drilled eight wells on the conventional shelf last year—three exploratory and five development—all of which were successful. W&T operates seven of those eight wells. These wells included two wells at our Ship Shoal 349 "Mahogany" field, three wells at our Main Pass 108 field, a well at Main Pass 180 and a well each at our South Timbalier 41 and South Timbalier 315 fields. The Mahogany field is our largest offshore field by category of proved reserves and the wells drilled in 2011 represent the first two of a potential six-well drilling program that could extend into 2013. We also completed a compressor project at our Main Pass 252 platform which expanded our total proved reserves by 2 MMBoe.



Onshore and Offshore Properties

Onshore, specifically in West Texas, was a very active area for us. In May, 2011, we acquired the Yellow Rose Properties adding 30 MMBoe of proved reserves at closing. Subsequently, we were successful on 45 of the 46 wells that were drilled to total depth last year. Twenty-nine wells were in the Permian Basin on the Yellow Rose Properties and 13 wells were in Terry County, Texas. The wells drilled in Terry County are all exploration wells and are still in the delineation phase of the project, but initial results have been encouraging. In East Texas we acquired 141,000 net acres and drilled one exploration well at our Star Project and we drilled another exploration well in our Branton East Project. Both wells are in various stages of completion, but the initial results appear positive.

For 2012, we have increased our capital budget to $425.0 million, excluding any potential acquisitions, representing a 37 percent increase over our 2011 capital budget. Exploration activities represent 39 percent of the budget, with the remainder devoted to development. We believe our capital plan contains the right mix of projects exposing us to large reserve targets and extended development opportunities that will sustain and grow production and cash flow.

Our 2012 budget is oriented primarily toward oil and liquids projects, which offer higher returns as oil and NGL prices continue to significantly outpace natural gas prices. This is particularly beneficial in the Gulf of Mexico where our oil production has been receiving a substantial pricing premium compared to West Texas Intermediate pricing. In 2012, we anticipate drilling a total of 75 wells—six exploratory and four development wells offshore and 19 exploratory and 46 development wells onshore. Our goals this year include increasing proved reserves by at least 18 percent. We plan to take a balanced approach to growth by executing a mix of development programs and exploration projects, complemented by acquisitions that fit our existing operations and strategic criteria. Although we don't usually budget for acquisitions, they have historically made a meaningful contribution to our growth profile. We expect 2012 to be no different. We evaluate

2011 HIGHLIGHTS:

ONSHORE

Drilled 46 Onshore wells with a 98% success rate.

Acquired the Yellow Rose properties in the Permian Basin adding 30 MMBoe of proved reserves at closing.

Added 173,000 net acres onshore.

Completed the first horizontal onshore well in the new East Texas acreage.

opportunities on a continuous basis, and deal flow remains robust as companies seek to raise cash or refocus their production profile. W&T's position in the Gulf of Mexico provides a tremendous vehicle for cash generation that enables us to move quickly to take advantage of acquisition opportunities that meet our investment criteria. We believe we are a preferred buyer of properties in the Gulf, based on more than 28 years of proven experience and safe operations, and now we are recognized as an onshore buyer as well.

All of us at W&T Offshore are proud of our accomplishments and our service to this great country in helping to meet our energy needs and we anticipate a stronger performance in 2012. As part of that, we will continue to pursue our successful business strategy of focusing on returns, managing cash and controlling costs, executing a successful drilling program, pursuing accretive acquisitions and remaining flexible while striving for operational and financial excellence. We believe that we can continue to evolve and grow and accomplish this in the proper manner by drilling within cash flow and maintain good liquidity to take advantage of acquisition and exploration opportunities. We are committed to the oil and gas industry, and bringing good jobs and affordable energy to America. We look forward to another great year of growing shareholder value.

Tracy W. Krohn
Founder, Chairman and CEO

2011 HIGHLIGHTS: OFFSHORE

Drilled 8 wells in the GOM with 100% success rate.

Closed the Fairway field acquisition ultimately adding 10.3 million barrels of oil equivalent of reserves as of December 31, 2011.

Completed the MP 252 "Tahoe" compressor project resulting in 2 million barrels of oil equivalent reserve addition.

BOARD OF DIRECTORS

Standing left to right, Samir G. Gibara, Stuart B. Katz, Virginia Boulet, S. James Nelson, Jr., B. Frank Stanley, Robert I. Israel, seated left to right, J. F. Freel, and Tracy W. Krohn

VIRGINIA BOULET, age 58, has served on the Board since March 2005. She is currently Chair of the Nominating and Corporate Governance Committee. She has been employed as Special Counsel to Adams and Reese, LLP, a law firm, since 2002. She is also an adjunct professor of law at Loyola University Law School. Prior to 2002, Ms. Boulet was a partner at the law firm Phelps Dunbar, LLP. Ms. Boulet has over 20 years of experience in mergers and acquisitions, equity securities offerings, general business matters and counseling clients regarding compliance with federal securities laws and regulations. Ms. Boulet currently serves on the board of directors of CenturyTel, Inc., a telecommunications company. Ms. Boulet received a B.A. in Medieval History from Yale University, and a J.D., cum laude, from Tulane University Law School.

SAMIR G. GIBARA, age 72, has served on the Board since May 2008. Mr. Gibara is the current Chair of our Compensation Committee and serves on the Audit Committee. 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 and remained as non-executive chairman until June 30, 2003. Prior to 1996, Mr. Gibara served that company in various managerial posts before being elected President and Chief Operating Officer in 1995. Mr. Gibara is a graduate of Cairo University and holds a M.B.A. from Harvard University. He has served on the boards of directors of Goodyear (1996 - 2003), Sumitomo Rubber Industries (1999 - 2002), Dana Corp. (2004 - 2008) and International Paper Company (1999 - 2011). Mr. Gibara is a member of the Investment Committee of the University of Akron Foundation.

ROBERT I. ISRAEL, age 62, has served on the Board since 2007. Mr. Israel serves on our Audit Committee. 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 U.S. and abroad. From 2000 to 2010, Mr. Israel was a Partner at Compass Advisers, LLP, a transatlantic strategic advisory and private investment firm, where he was the head of the firm's energy practice. From 1990 to 2000, Mr. Israel was the head of the Energy Department of Schroder & Co., Inc. Currently, Mr. Israel is a member of the board of directors of Randgold Resources Limited, Brasoil, Suelopetrol C.A., Hart Energy Publishing, and API, Inc. Mr. Israel holds a M.B.A. from Harvard University and a B.A. from Middlebury College.

STUART B. KATZ, age 57, previously served on the Board from 2002 to 2008 and was reappointed to serve on the Board in April 2011. Mr. Katz serves on our Audit and Compensation Committees. Since 2007, Mr. Katz has served as Chief Executive Officer of Alconox, Inc., a private company engaged in the manufacturing and marketing of specialty chemicals. From 2001 to 2010, Mr. Katz was a Managing Director of Jefferies Capital Partners ("JCP"), a private equity investment fund. In 2002, Mr. Katz joined the Board in connection with JCP's investment in the Company. In May 2008, Mr. Katz declined to stand for reelection to the Board in connection with JCP's divestment of its remaining equity interest in the Company. Prior to joining JCP in 2001, Mr. Katz had been an investment banker with Furman Selz LLC and its successors for over 16 years. Mr. Katz received a B.S. in engineering from Cornell University and a J.D. from Fordham Law School. Mr. Katz is a member of the bar of the State of New York.

TRACY W. KROHN, age 57, has 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. He is also a member of the Nominating and Corporate Governance Committee. 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. From 1996 to 1997, Mr. Krohn was also Chairman and Chief Executive Officer of Aviara Energy Corporation in Houston, Texas.

S. JAMES NELSON, JR., age 69, has served on the Board since January 2006. He is currently Chair of the Audit Committee and also serves as Presiding Director. 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 has an extensive background in accounting and financial matters from his time as a Partner at Arthur Andersen & Co. and his time as Chief Financial Officer at Apache Corporation and Diversified Energies, Inc. Mr. Nelson received a B.S. in Accounting from Holy Cross College and holds a M.B.A. from Harvard University. He is also a certified public accountant. Additionally, Mr. Nelson serves on the boards of directors of Oil States International, Inc., ION Geophysical, and Genesis Energy, LP.

B. FRANK STANLEY, age 57, has served on the Board since 2009. Mr. Stanley serves as member of our Audit, Compensation and Nominating and Corporate Governance Committees. Mr.Stanley has an extensive background in accounting and financial matters and is currently Chief Executive Officer and Chief Financial Officer of Retails Concepts, Inc., a privately-held retain chain of 28 stores in 13 states. Mr. Stanley holds a B.B.A. in Accounting from Texas A&M University and is a certified public accountant.

IN MEMORIAM

All of us at W&T Offshore were saddened over the loss of Company Co-Founder Jerome F. "Jere" Freel on December 2, 2011, at age 99. Jere served on the Board since the Company's inception and as Corporate Secretary since 1989. He joined Humble Oil and Refining Company in 1934 after graduating college and went on to form Research Explorations, Inc., and Kiowa Minerals Company before founding W&T with Tracy Krohn in 1983. Jere was a kind and gentle man who reveled in the success of W&T and its employees. We believe that was a big key to his longevity. We are blessed by his memory. He was our hero!

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, 2011

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 (§ 232.405 of this chapter) 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 (§ 229.405 of this chapter) 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 (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock held by non-affiliates was approximately $910,229,000 based on the closing sale price of $26.12 per share as reported by the New York Stock Exchange on June 30, 2011.

The number of shares of the registrant's common stock outstanding on February 23, 2012 was 74,351,533.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, are incorporated by reference into Part III of this Form 10-K.

W&T OFFSHORE, INC.
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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements 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 under the circumstances. Known material risks that may affect our financial condition and results of operations are discussed in Item 1A, Risk Factors, and market risks are discussed in 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"). Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. 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, exploration and development of oil and natural gas properties primarily in the Gulf of Mexico and Texas.

The Gulf of Mexico 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 explore and develop 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.

During 2011, we significantly increased our activity onshore from what was previously a relatively minor presence. In May 2011, we acquired various properties and leasehold interests in four counties in the Permian Basin of West Texas (as described below) in a single transaction and separately acquired other leasehold interests in another county in the Permian Basin. In East Texas, we have acquired leasehold interests in two separate prospect areas. We have been actively exploring and developing each of these areas and have had up to eight drilling and workover rigs in service in our onshore operating areas during the year. We anticipate being active in both of these areas of Texas in 2012.

As of December 31, 2011, we have interests in offshore leases covering approximately 0.8 million gross acres (0.5 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. Onshore, we have leasehold interests in approximately 0.2 million gross acres (0.2 million net acres), all of which are in Texas. Approximately 82% of our total net offshore acreage is developed and approximately 9% of our total net onshore acreage is developed. Of the onshore leasehold classified as undeveloped, almost all can be extended by drilling two additional wells in 2012 and further extended by additional operations or production in future years.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent petroleum consultant, our total proved reserves at December 31, 2011 were 116.9 million barrels of oil equivalent (“MMBoe”) or 701.1 billion cubic feet equivalent (“Bcfe”). Approximately 46% of our reserves were classified as proved developed producing, 19% as proved developed non-producing and 35% as proved undeveloped. Classified by product, our reserves at December 31, 2011 were 44% oil, 15% natural gas liquids (“NGLs”) and 41% natural gas. These percentages were determined using the ratio of six thousand cubic feet (“Mcf”) of natural gas to one barrel (“Bbl”) of crude oil, condensate or NGLs. This conversion ratio does not assume price equivalency, and the prices for oil, NGLs and natural gas per Mcfe may differ significantly. During 2011, prices for oil were higher than NGLs and natural gas on a million cubic feet equivalent (“Mcfe”) basis, and prices for NGLs were higher than natural gas on a Mcfe basis. Our total proved reserves had an estimated present value of future net revenues discounted at 10% (“PV-10”) of $3.1 billion. Our PV-10 after considering future cash outflows related to asset retirement obligations (“ARO”) and without deducting future income taxes was $2.8 billion, and our standardized measure of discounted future cash flows was $2.0 billion as of December 31, 2011. For additional information about our proved reserves and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, see *Properties – Proved Reserves* under Part I, Item 2 of this Form 10-K.

We seek to increase our reserves through acquisitions, drilling, recompletions and workovers. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to add reserves, production and cash flow 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.

As previously mentioned, in May 2011, we completed the acquisition of approximately 24,500 gross acres (21,900 net acres) of oil and gas leasehold interests in the Permian Basin of West Texas, which we refer to as our "Yellow Rose Properties," from Opal Resources LLC and Opal Resources Operating Company LLC (collectively, "Opal"). Based on internal estimates, the proved reserves associated with the Yellow Rose Properties as of the acquisition date were approximately 30.1 MMBoe (180.4 Bcfe), comprised of approximately 69% oil, 22% NGLs and 9% natural gas, and approximately 70% of which were classified as proved undeveloped. Including adjustments from an effective date of January 1, 2011, the adjusted purchase price was $394.4 million, and we assumed the ARO associated with the Yellow Rose Properties, which we have estimated to be $0.4 million, and recorded a long-term liability of $2.1 million.

In August 2011, we completed the acquisition of Shell Offshore Inc.'s ("Shell") 64.3% interest in the Fairway Field along with a like interest in the associated Yellowhammer gas treatment plant (collectively, the "Fairway Properties"). Based on internal estimates, the proved reserves associated with the Fairway Properties as of the acquisition date were 8.9 MMBoe (53.5 Bcfe), comprised of approximately 72% natural gas, 27% NGLs and less than 1% oil and which are 100% proved developed. Including adjustments from an effective date of September 1, 2010, the adjusted purchase price was $42.9 million and we assumed the ARO associated with the Fairway Properties which we have estimated to be $7.8 million.

During 2010, we closed on two major acquisitions. In April 2010, we acquired two deepwater Gulf of Mexico fields (the "Matterhorn/Virgo Properties") from Total E&P USA ("Total") and in November 2010, we acquired three deepwater Gulf of Mexico fields (the "Tahoe/Droshky Properties") from Shell.

Additional information on these acquisitions can be found in *Properties* under Part I, Item 2, *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 and in *Financial Statements – Note 2 – Acquisitions* under Part II, Item 8 of this Form 10-K.

Our exploration efforts historically have been in areas in reasonably close proximity to 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 an offshore well and future development of an offshore 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. Onshore wells are less capital intensive than offshore wells, but the amount of reserves discovered and developed on a per well basis has historically been less than offshore wells. During the last three years, we have drilled eight, six and 10 successful offshore wells (gross) for the years 2011, 2010 and 2009, respectively and drilled 39 successful onshore wells (gross) in 2011.

From time to time, as part of our business strategy, we sell various properties that we consider non-core assets. We did not sell any properties in 2011 or 2010. We are currently marketing a package of non-core properties located on the shelf of the Gulf of Mexico.

We generally sell our oil, NGLs 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 2012 is $425.0 million, not including any potential acquisitions. The budget includes $209.0 million to drill, evaluate and complete ten offshore wells (six exploration and four development wells) and $170.0 million to drill, evaluate and complete 65 onshore wells (19 exploration and 46 development wells). The budget also includes $46.0 million for facilities capital, recompletions, seismic and leasehold items. Thus far in 2012, we have not closed on any acquisitions and continue to evaluate and bid on opportunities as they arise. We anticipate funding our 2012 capital budget and any potential acquisitions with cash flow from operating activities, cash on hand, borrowings under our revolving bank credit facility and by accessing the capital markets to the extent necessary. Our 2012 capital budget is subject to change as conditions warrant. 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, explore and develop 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 and, more specifically, the significant decline in natural gas prices, 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 continue 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 in Texas and anticipate acquiring or expanding our onshore holdings through acquisitions or exploration and development activities.

We believe our business 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 revolving bank credit facility for acquisitions and to balance working capital fluctuations.

Competition

The oil and natural gas industry is highly competitive. We currently operate in the Gulf of Mexico and Texas 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 *Risk Factors* in Part I, Item 1A of this Form 10-K.

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil, NGLs 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 2011 we sold over 10% of our production to each of Shell Trading (US) Co., Conoco Phillips and JP Morgan Ventures Energy Corp. and these three companies accounted for approximately 62% of our total sales. See *Financial Statements – Note 1 – Significant Accounting Policies – Concentration of Credit Risk* in Part II, Item 8 of this Form 10-K 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 with numerous purchasers in the Gulf of Mexico and Texas, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production. We do not have agreements that obligate us to deliver certain quantities to third parties.

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 NGLs 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. The RRC was subject to a sunset condition and proposals for certain changes were made, but no legislation was enacted during 2011 and the RRC will be reviewed again in 2013.

The Outer Continental Shelf Lands Act ("OCSLA"), which is administered by the Bureau of Ocean Energy Management [(1)] ("BOEM") 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 BOEM 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 British thermal units ("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 BOEM 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 NGLs 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.

[(1)] In June 2010, the Minerals Management Service changed its name to the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"). In October 2011, the BOEMRE was split into three separate entities: the Office of Natural Resources Revenue ("ONRR"), which assumed the functions of the Minerals Revenue Management Program; the Bureau of Ocean Energy Management, which is responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way; and the Bureau of Safety and Environmental Enforcement ("BSEE"), which is responsible for enforcement of safety and environmental regulations.

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 they affect other crude oil, condensate and natural gas liquids producers or marketers.

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

Federal leases. Most of our operations are conducted on federal oil and natural gas leases, which are administered by the BOEM pursuant to the OCSLA. These leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEM regulations and orders that are subject to interpretation and change by the BOEM. The BOEM 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 *Risk Factors* under Part I, Item 1A in this Form 10-K for more information on new regulations.

To cover the various obligations of lessees on the OCS, the BOEM 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. W&T Offshore, Inc. is currently exempt from supplemental bonding requirements by the BOEM. As many BOEM regulations are being reviewed, we may be subject to supplemental bonding requirements in the future. Under some circumstances, the BOEM 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 *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* under Part I, Item 1A in this Form 10-K for more information.

The ONRR 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 ONRR and the BOEM.

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 BOEM and the BSEE continue 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 BOEM and the BSEE have 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 BOEM and the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs and/or capital expenditures.

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 in the Gulf of Mexico 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 are currently under investigation by the United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the U.S. Environmental Protection Agency (the "EPA") for alleged violation of environmental laws and regulations at certain of our operational sites. The outcome of this investigation could have a material adverse effect upon us. We are not able at this time to estimate our potential exposure, if any, related to this matter. See Legal Proceedings under Part I, Item 3 in this Form 10-K for additional information. At our other operation sites, we believe we are in substantial compliance with current applicable environmental laws and regulations. We believe that compliance with existing requirements will not have a material adverse impact on our operations, but failure to comply could have material consequences. 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.

Air emissions from our operations are subject to the Clean Air Act ("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. On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA's proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. EPA is currently considering comments submitted on the proposed rules and has indicated that it expects to adopt final rules by April 3, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results. 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 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 effective 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. We expect to be able to comply with this emissions reporting requirement for our onshore operations in West Texas.

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, NGLs 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, 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 a maximum of $150 million. We are currently required to demonstrate, on an annual basis, that we have ready access to $150 million that can be used to respond to an oil spill from our facilities on the OCS. 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. 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 was 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.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Effective February 1, 2012, the RRC began requiring all operators to disclose on a public website the chemical ingredients and water volumes used to hydraulically fracture wells in Texas. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells that require hydraulic fracturing.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

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 BSEE 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 could be required. The U.S. Fish and Wildlife Service is currently considering whether the dunes sagebrush lizard, which is present in certain areas of the Permian Basin near the Texas-New Mexico border, should be listed as endangered. It is possible that a decision to list the dunes sagebrush lizard as endangered could have an adverse impact on our operations in West Texas.

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 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 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 liability insurance and well control insurance for all of our operations. In addition, we maintain property and hurricane damage insurance coverage for some, but not all, of our properties, 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 from gradual pollution events 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 *Management's Discussion and Analysis of Financial Condition and Results of Operations – Inflation and Seasonality* under Part II, Item 7 of this Form 10-K.

Employees

As of December 31, 2011, we employed 310 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 reports 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. Information on our website is not a part of this Form 10-K.

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 known material 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;
- 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;
- the price and availability of alternative fuels; and
- geographic differences in pricing.

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, excess natural gas production, 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, as well as natural gas produced in connection with increased domestic oil drilling activities. 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 and/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-downs in 2011 or 2010. Declines in oil and natural gas prices after December 31, 2011 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 *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Impairment of oil and natural gas properties* in Part II, Item 7 and *Financial Statements – Note 1 – Significant Accounting Policies* in Part II, Item 8 of this Form 10-K for additional information on the ceiling test.

The Company is responding to a federal grand jury investigation that could result in penalties and additional operating restrictions.

The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the EPA, is conducting a federal grand jury investigation of environmental compliance matters relating to surface discharges and reporting on four of our offshore platforms in the Gulf of Mexico. We are fully cooperating with the investigation. The United States Attorney's Office has recently informed us that they are continuing their investigation with the intent to seek a criminal disposition. The outcome of this investigation could have a material adverse effect upon us. We are not able at this time to estimate our potential exposure, if any, related to this matter.

The Company has been sued by certain landowners alleging damages to their properties.

On May 6, 2009, certain Cameron Parish land owners filed suit in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and Tracy W. Krohn as well as several other defendants unrelated to us. In their lawsuit, plaintiffs are alleging that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and are seeking compensatory and punitive damages. We cannot currently estimate our potential exposure, if any, related to this lawsuit. We are currently, and intend to continue, vigorously defending this litigation.

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 the deep water of 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, and substantial rules adopted, 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 BOEM and BSEE issued a series of NTLs imposing a variety of new safety measures and permitting requirements. They also imposed a six-month moratorium on drilling activities in federal offshore waters that stretched into a much longer moratorium resulting in delays in not only deepwater drilling but also in many other types of activities in the Gulf of Mexico that continue to exist currently.

In addition to the drilling restrictions, new safety measures and permitting requirements already issued by the BOEM and BSEE, 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 operators to provide evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. We are currently required to demonstrate, on an annual basis, that we have ready access to $150 million that can be used to respond to an oil spill from our facilities on the OCS. Legislation has been proposed in Congress to amend OPA to increase the minimum level of financial responsibility to $300 million or more. If the minimum level of financial responsibility is increased further, we may experience difficulty in providing financial assurances sufficient to comply with the revised requirement. 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 further.

After the moratorium ended in 2010, it was not until March 2011 that deep water drilling permits began to be issued, and even then only sporadically, to continue drilling activities that had commenced prior to the Deepwater Horizon incident. Since March 2011, deepwater drilling permits have been issued at a slower and more measured pace than before the Deepwater Horizon event.

Other significant regulatory changes since the Deepwater Horizon event are regulations related to assessing the potential environmental impact of future spills using worse case discharge scenarios on a well-by-well basis, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental management system. The new regulations and increased review process increases the time it takes to obtain drilling permits and increases the cost of operations. As these new regulations and guidance continue to evolve, the risk to our business may be increased. The permitting process is also slow and inconsistent for shallow water work and even for plug and abandonment activities. This could lead to increased costs and performing work at less than optimal effectiveness. We have not experienced delays in obtaining permits related to our onshore operations.

Regulatory requirements, NTLs and permitting procedures imposed by the BOEM and BSEE 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 BOEM and BSEE 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, the BOEM 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 the BOEM 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 cause some of our leases to lapse as a result of failure to commence drilling or continue production operations.

New requirements imposed by the BOEM and BSEE could significantly impact the cost of operating our business.

In addition to the NTLs discussed previously, the BOEM 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 requiring 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 *Financial Statements – Note 5 – Asset Retirement Obligations* in Part II, Item 8 of this Form 10-K.) The potential increase in decommissioning activity in the Gulf of Mexico over the next few years as a result of the NTL may result in increased demand for salvage contractors and equipment, resulting in increased estimates of plugging, abandonment and removal costs and increases in related ARO.

Recently proposed rules regulating air emissions from oil and gas operations could cause us to incur increased capital expenditures and operating costs.

On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA's proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and VOCs and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA's proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA is currently considering comments submitted on the proposed rules and has indicated that it expects to adopt final rules by April 3, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results.

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 resulting in write-downs of 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. There are likely to be long-term effects resulting from the recession, the credit market crisis and the recent issues concerning the Euro and the debt of certain European countries. These and other factors may cause future economic growth rate to be 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 could result in decreased demand growth for our oil and natural gas production as well as lower commodity prices, which could reduce our cash flows from operations and our profitability.

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

As of December 31, 2011, available borrowings under our revolving bank credit facility are currently limited to $575.0 million, less outstanding borrowings and letters of credit. Availability is determined semi-annually by 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 governing our revolving bank credit facility (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 credit 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 May and June 2011, we renewed our insurance policies covering well control and hurricane damage at an annual cost of approximately $30.7 million. The amount of properties covered and dollar coverage was increased from 2010, but the retention amount per hurricane occurrence was also increased, which increases our risk. In addition, pollution and environmental risks are generally 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.

See *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims* under Part II, Item 8 of this Form 10-K for additional information.

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 insurance claims in recent years associated with hurricanes in the Gulf of Mexico and global catastrophic losses, property damage and well control insurance coverage has become more limited and the cost of such coverage has become both more costly and more volatile. The insurance market may change dramatically in the future due to the major oil spill that occurred in 2010 at BP's Macondo well in the deepwater Gulf of Mexico. As of December 31, 2011, approximately 93% of our PV-10 value of proved reserves attributable to our Gulf of Mexico properties are on platforms that are covered under our current insurance policies for named windstorm damage. 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 possibilities 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.

Commodity derivative positions 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 commodity derivative positions with respect to a portion of our expected production. We do not enter into derivative instruments for speculative trading purposes. While these commodity derivative positions 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 such positions. 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 derivative contracts fail to perform under the terms of the contracts.

See *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K for additional information on derivative transactions.

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

Current SEC guidance requires 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, 2011, approximately 35% of our total proved reserves were undeveloped and approximately 19% 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.

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 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 our current reserves and economically finding or acquiring additional recoverable reserves.

Relatively short production periods for our Gulf of Mexico 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 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 majority of our current production is from the Gulf of Mexico. Production from reservoirs in the Gulf of Mexico generally decline more rapidly than from reservoirs in many other producing regions of the United States. Our independent petroleum consultant estimates that, on average, 43% 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 larger portion of their reserves in areas other than the Gulf of Mexico. We may not be able to develop, 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 operating activities, 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, bank borrowings, reserve-based loans, joint ventures 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 BOEM 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, development 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 less 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 interpret 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 concentrated 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 platform damage.

As described above in the risk factor titled *"New requirements recently imposed by the BOEM and BSEE could significantly impact the cost of operating our business,"* the BOEM'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 exploration and development 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 and such participants' financial resources;
- 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 us that 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 oil and natural gas exploration and production activities, including well stimulation and completion activities which include, among other things, hydraulic fracturing, involve 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 or failures;
- 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, encountering NORM, and discharges of brine, well stimulation and completion fluids, toxic gases, or other pollutants into the surface and subsurface environment.

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, development 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 specifically affecting the Gulf of Mexico.

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 a majority of our properties could experience the same conditions 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. For example, in 2009, net production of approximately 8.7 Bcfe 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 also have some different regulations, interpretation of regulations and enforcement by the particular state in which the operations are conducted. Until 2011, our experience has primarily been with offshore operations. We are subject to and must comply with the various state regulations and work effectively with the state agencies, and failure to do so may impact our operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. We utilize hydraulic fracturing techniques in connection with developing our recently acquired Yellow Rose Properties and other properties. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. The EPA, however, recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA Underground Injection Control Program and has begun the process of drafting guidance documents on regulating requirements for companies that plan to conduct hydraulic fracturing using diesel fuel. In addition, a number of federal agencies are analyzing a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities, with initial results expected to be available by late 2012 and final results by 2014. A number of other federal agencies, including the U.S. Department of Energy, Department of Interior, and White House Council on Environmental Quality, are also studying various aspects of hydraulic fracturing. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Legislation also has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local governments have adopted, and other states and local governments are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations, including states in which we operate. For example, effective February 1, 2012, the RRC began requiring all operators to disclose on a public website the chemical ingredients and water volumes used to hydraulically fracture wells in Texas. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to associated permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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, NGLs 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, 2011. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and natural gas reserve quantities,* Part II, Item 7 for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in *Business* in Part I, Item 1, *Properties* in Part I, Item 2 and *Financial Statements – Note 22 – Supplemental Oil and Gas Disclosures* in Part II, Item 8 of this Form 10-K.

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 an area of land in which we own an interest, could acquire an interest or have operating rights, and have what our geoscientists believe, based on available seismic and geological information, to be indications of economic accumulations 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, we can offer no assurance that we will find commercial quantities of oil and natural gas and, therefore, we can offer 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. For example, 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, 2011, four fields, accounting for approximately 2.2 Bcfe (or 2%) of our 2011 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, or if the prices charged by these third-party pipelines increase, our revenues or costs 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, a third-party pipeline used by our Main Pass 108 field was shutdown between June 2010 and March 2011. We estimate this shutdown caused us to defer production of approximately 4.9 Bcfe during 2010 and 3.7 Bcfe during 2011.

Certain third-party pipelines have submitted or have made plans to submit requests to increase the fees they charge us to use these pipelines. These increased fees could adversely impact our revenues or operating costs, either of which would adversely impact our operating profits and cash flows.

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 site 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 *Business – Regulation,* Part I, Item 1 of this Form 10-K 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.

We are currently under investigation by the United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the EPA for alleged violations of environmental laws and regulations. See *Legal Proceedings* in Part I, Item 3 in this Form 10-K for additional information. Also, in prior years, 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 *Business – Regulation*, Part I, Item 1 of this Form 10-K 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 the 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 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 affects 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.*

Implementation of financial reform legislation and regulations could have an adverse effect on our ability to use derivative instruments to reduce the negative effect of commodity price changes, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was adopted in July 2010, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The law required the Commodity Futures Trading Commission (the "CFTC") and the SEC to implement rules and regulations within 360 days from the date of enactment. In December 2011, the CFTC extended temporary exemptive relief from regulations on certain provisions of the Dodd-Frank Act applicable to swaps until no later than July 16, 2012. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final 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 are exempt from these position limits. It is not possible at this time to predict when the CFTC will make these regulations effective. 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 legislation and 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.

Our operations could be adversely impacted by security breaches, including cyber-security breaches, which could affect our production of oil and natural gas or could affect other parts of our business.

We face security exposure, including cyber-security exposure, from unauthorized access to our facilities and computer systems. This exposure includes unauthorized access to sensitive information; malicious damage to our facilities, infrastructure, and computer systems; malicious damage to third-party facilities, infrastructure, and computer systems; safety exposure for our employees and contractors; and disruptions of our operations. Although we utilize various procedures and controls to mitigate these exposures, there can be no assurances that these procedures and controls will be sufficient to prevent such events from occurring. Cyber-security exposures in particular are evolving and include malicious software, unauthorized access to confidential data and disruptions to operations that use computers and data systems. We do not carry business interruption insurance. Any of these security breaches could have a material adverse affect on our consolidated financial position, results of operations and cash flows.

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 Corporate 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 *Executive Officers of the Registrant* in Part I following Item 3 in this Form 10-K for more information regarding our senior 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 U.S. 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 or Texas, 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, NGLs 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, NGLs 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.

For 2011 and 2012 to date, world financial markets have been affected by the instability of the Euro and the uncertainty of some Euro-based countries to repay their debt. In addition, one credit agency downgraded the debt of the U.S. government. These types of events bring uncertainty to the financial markets and may produce volatility and may decrease financing availability.

In recent years, access to financing markets was severely limited. For example, in 2009, the global financial markets and economic conditions were severely distressed. There were concerns, both with respect to bank failures and bank liquidity, as to whether our banks would be able to meet their commitments under credit arrangements in place during that time. These concerns led to very few financing transactions being completed. In addition, prices for oil, NGLs and natural gas had decreased from 2008.

We can offer 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. Our revolving bank credit facility is subject to semi-annual borrowing base determination, and available credit could be reduced or eliminated at the sole discretion of the banks within the facility.

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 off our outstanding indebtedness. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or initiatives by our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our current or 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.

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 39,206,962 shares of our common stock, representing approximately 52.7% of our voting interests as of February 17, 2012. As a result, Mr. Krohn has the ability to control the outcome of matters that require a simple majority of shareholders for 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.

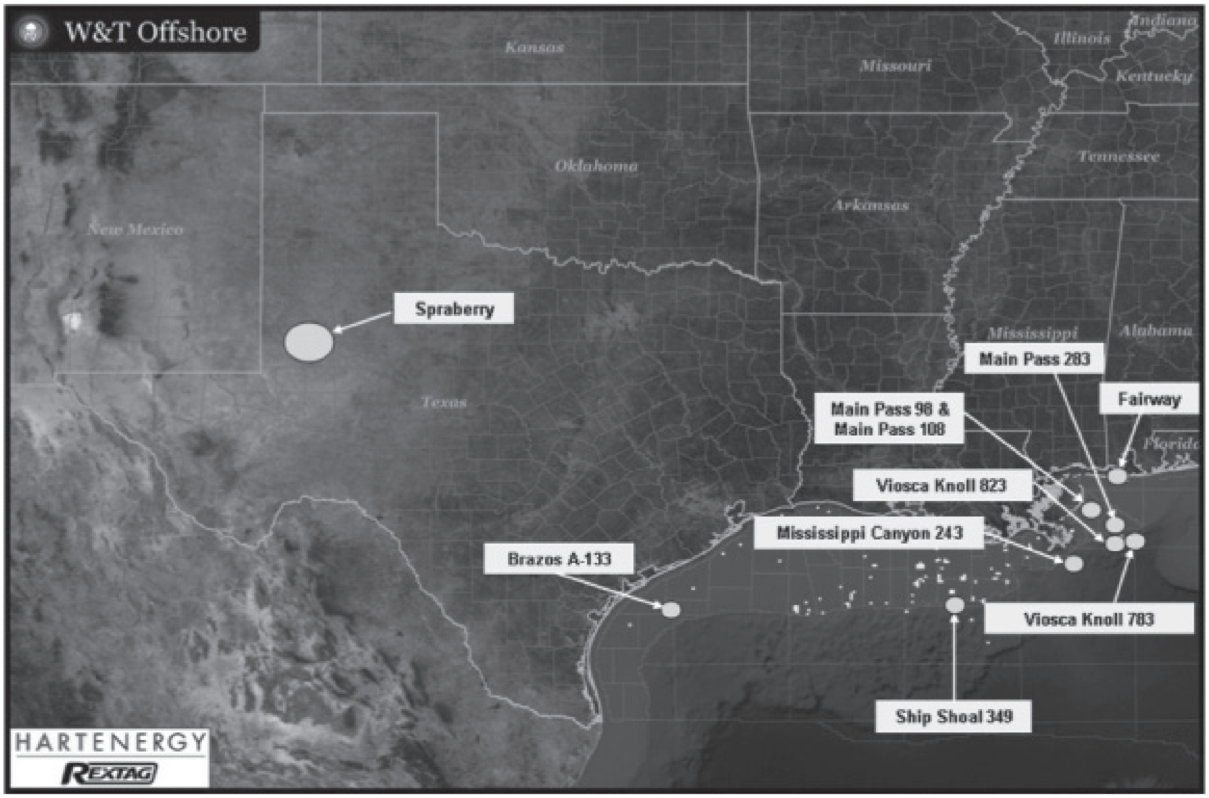
Due to Mr. Krohn's ownership and control, we are exempted from many New York Stock Exchange corporate governance rules, and, as a result, our other shareholders may not have the protections set forth in those rules, particularly in the event of conflicts of interest with Mr. Krohn.

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***



Our fields are located in the Gulf of Mexico, Alabama and in Texas. The offshore fields are found in water depths ranging from less than ten feet up to 4,200 feet. The reservoirs in our offshore fields are generally characterized as having high porosity and permeability, which typically results in high production rates. The reservoirs in our onshore fields are generally characterized as having low porosity and permeability and require stimulation and artificial lift to produce. The following describes our ten largest fields as of December 31, 2011, based on quantities of proved reserves on a natural gas equivalent basis. At December 31, 2011, these fields accounted for approximately 84% of our proved reserves.

Field Name	Field Category	Operator	Percent Oil and NGLs of Net Reserves (1)	Percent Natural Gas of Net Reserves (1)	2011 Average Daily Equivalent Sales Rate (MMcfe/d) (1) Gross	Net
Spraberry (Yellow Rose Properties)	Onshore	W&T	89%	11%	20.3	14.0
Ship Shoal 349 (Mahogany)	Shelf	W&T	84%	16%	11.2	9.1
Viosca Knoll 783 (Tahoe/SE Tahoe)	Deepwater	W&T	28%	72%	67.5	37.5
Main Pass 108	Shelf	W&T	22%	78%	30.8	20.8
Fairway (Fairway Properties)	Shelf	W&T	25%	75%	57.1	26.3
Miss. Canyon 243 (Matterhorn)	Deepwater	W&T	76%	24%	27.0	26.5
Viosca Knoll 823 (Virgo)	Deepwater	W&T	34%	66%	13.9	7.9
Main Pass 98	Shelf	W&T	29%	71%	10.4	7.8
Brazos A-133	Shelf	Apache	1%	99%	32.0	6.4
Main Pass 283	Shelf	W&T	51%	49%	22.1	15.5

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

Our Fields

On December 31, 2011 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 Spraberry field is located in the Permian Basin in West Texas and the Ship Shoal 349 field is located on the conventional shelf in the Gulf of Mexico. Below is a description of these fields.

Spraberry Field (Yellow Rose Properties).

The Spraberry field is located in the Permian Basin in West Texas. W&T acquired a 100% working interest in approximately 21,900 net acres in connection with the acquisition of the Yellow Rose Properties in May 2011 and acquired approximately 9,500 net acres earlier in 2011. The Spraberry Field was discovered in 1935 and extends over several counties in West Texas comprising about 1.6 million acres. The field is 150 miles long and 75 miles wide, and it has undergone much change and expansion over the years, both aerially and vertically. The correlative interval is now over 3,500 feet thick and includes the Clearfork, Upper Spraberry, Lower Spraberry, Dean, and Wolfcamp formations. These formations are correlative over the area but are lenticular in nature and vary in thickness, porosity, and permeability even over short distances. The general completion technique includes hydraulic fracturing and installation of sucker rod pumps. W&T is currently employing a three rig drilling program to continue developing the field.

From 2006 through 2011, 119 wells were drilled on acreage in which we currently have an ownership interest and 118 were successful, including 29 wells we drilled to target depth subsequent to our acquisition of the Yellow Rose Properties. Cumulative field production during this time was 2 MMBoe (11 Bcfe) from our wells. Total proved reserves associated with our interest in the Spraberry field were 28.1 MMBoe (168.5 Bcfe) at December 31, 2011.

The following presents historical information about our produced oil, NGLs and natural gas volumes from the Spraberry field from the acquisition date of May 11, 2011 through December 31, 2011. As we have had limited history operating the Spraberry field, the amounts below may not be representative of future results.

	May - December 2011
Net sales:	
Oil (MBbls) (1)	452.3
NGLs (MBbls)	60.3
Natural gas (MMcf)	213.5
Total oil equivalent (MBoe) (2)	548.2
Total natural gas equivalent (MMcfe)	3,289.2
Total oil equivalent (Boe/day)	2,333
Total natural gas equivalent (MMcfe/day)	14.0
Average realized sales prices:	
Oil ($/Bbl)	$ 91.09
NGLs ($/Bbl)	51.70
Natural gas ($/Mcf)	3.05
Oil equivalent ($/Boe) (3)	82.03
Natural gas equivalent ($/Mcfe)	13.67
Average production costs (4):	
Oil equivalent ($/Boe)	$ 13.62
Natural gas equivalent ($/Mcfe)	2.27

(1) One thousand barrels of oil ("MBbl").

(2) One thousand barrels of oil equivalent ("MBoe").

(3) Barrels of oil equivalent (“Boe”).
(4) Includes lease operating expenses and gathering and transportation costs.

Ship Shoal 349 Field (Mahogany). 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 Amoco 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 2011 is approximately 30 MMBoe gross (179 Bcfe gross). This field is a sub-salt development with five productive horizons below salt at depths up to 17,000 feet. As of December 31, 2011, 24 wells have been drilled, of which 15 have been successful. In 2010, we developed a reservoir simulation model to determine the most optimal future development plan. As a result, in 2011, we drilled one development well and one exploration well. In January 2012, the third well was spud as part of an ongoing drilling program. Total proved reserves associated with our interest in this field were 20.3 MMBoe (121.7 Bcfe) at December 31, 2011.

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

	Year Ended December 31,		
	2011	2010	2009
Net sales:			
Oil (MBbls)	445.2	656.7	675.7
NGLs (MBbls)	22.7	37.9	47.7
Natural gas (MMcf)	497.8	862.8	772.8
Total oil equivalent (MBoe)	550.8	838.4	852.2
Total natural gas equivalent (MMcfe)	3,304.9	5,030.3	5,112.9
Total oil equivalent (Boe/day)	1,509	2,297	2,335
Total natural gas equivalent (MMcfe/day)	9.1	13.8	14.0
Average realized sales prices:			
Oil ($/Bbl)	$ 101.30	$ 73.20	$ 55.75
NGLs ($/Bbl)	56.06	43.54	29.43
Natural gas ($/Mcf)	4.20	4.88	4.56
Oil equivalent ($/Boe)	87.97	64.33	49.99
Natural gas equivalent ($/Mcfe)	14.66	10.72	8.33
Average production costs (1):			
Oil equivalent ($/Boe)	$ 14.30	$ 13.20	$ 14.57
Natural gas equivalent ($/Mcfe)	2.38	2.20	2.43

(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, 2011, of which five are located on the conventional shelf and three are located in the deepwater. We do not believe that individually any of these properties are of major significance (each has proved reserves which comprise less than 15% of our total proved reserves, calculated on a natural gas equivalent basis).

Viosca Knoll 783 Field. (Viosca Knoll 783 Lease (Tahoe) and Viosca Knoll 784 Lease (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 subsea tiebacks to two platforms in Main Pass 252. Shell discovered the Tahoe prospect in 1984 and the SE Tahoe prospect in 1996.

We acquired a 70% working interest in Tahoe lease and a 100% working interest in SE Tahoe lease from Shell in 2010. Cumulative field production through 2011 is approximately 88 MMBoe gross (526 Bcfe gross). The Tahoe prospect is a supra-salt (above the salt layer) development with two productive horizons at depths ranging to 10,300 feet. The SE Tahoe prospect is also a supra-salt development with one productive horizon at a depth of 9,325 feet. As of December 31, 2011, 16 wells have been drilled at the Tahoe prospect, of which eight have been successful and one successful well has been drilled at the SE Tahoe prospect. During December 2011, production from this field, net to our interest, averaged 260 Bbls of oil per day, 860 Bbls of NGLs per day and 18.9 MMcf of natural gas per day, for total production of 4.3 MBoe per day (25.6 MMcfe per day).

Fairway Field (Fairway Properties). Fairway is comprised of Mobile Area blocks 113 (Alabama State Lease #0531) and 132 (Alabama State Lease #0532) and located in 25 feet of water, approximately 35 miles south of Mobile, Alabama. We acquired our 64.3% working interest, along with operatorship in the Fairway field, from Shell in August 2011. The field was discovered in 1985 with Well 113 #1 (now called JA). Development drilling began in 1990 and was completed in 1991 with the addition of four wells, each drilled from separate surface locations. The five producing wells came on line in late 1991. As of December 31, 2011, six wells have been drilled, all of which were successful. Cumulative field production through 2011 is approximately 117 MMBoe gross (704 Bcfe gross). This field is a Norphlet sand dune trend development with one producing horizon at an approximate depth of 21,300 feet. During December 2011, production from this field, net to our interest, averaged seven Bbls of oil per day, 1,365 Bbls of NGLs per day and 14.6 MMcf of natural gas per day, for total production of 3.8 MBoe per day (22.8 MMcfe per day).

Main Pass 108 Field. Main Pass 108 field consists of Main Pass blocks 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, 2011, 42 wells have been drilled in this field, of which 34 were successful. Cumulative field production through 2011 is approximately 46 MMBoe gross (275 Bcfe gross). In early June 2010, a third party pipeline that was used to transport production from the field was shutdown due to damage. A new line was installed and the production rerouted at the end of March 2011. During 2010 and 2011, additional wells were successfully drilled, recompleted or workovers were performed which increased production and added reserves. Production from the field resumed in April 2011 and is currently at a higher daily rate than before the pipeline shutdown. During December 2011, production from this field, net to our interest, averaged 444 Bbls of oil per day, 425 Bbls of NGLs per day and 19.9 MMcf of natural gas per day, for total production of 4.2 MBoe per day (25.2 MMcfe per day).

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 2011 is approximately 21 MMBoe gross (124 Bcfe gross). This field is a supra-salt development with 17 productive horizons at depths ranging to 9,850 feet. As of December 31, 2011, 17 wells have been drilled, of which eight have been successful. During December 2011, production from this field, net to our interest, averaged 3,150 Bbls of oil per day, 288 Bbls of NGLs per day and 11.4 MMcf of natural gas per day, for total production of 5.3 MBoe per day (32.0 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 2011 is approximately 20 MMBoe gross (117 Bcfe gross). This field is a supra-salt development with 17 productive horizons at depths ranging to 13,335 feet. As of December 31, 2011, 12 wells have been drilled, of which ten have been successful. During December 2011, production from this field, net to our interest, averaged 153 Bbls of oil per day, 76 Bbls of NGLs per day and 5.9 MMcf of natural gas per day, for total production of 1.2 MBoe per day (7.3 MMcfe per day).

Main Pass 98 Field. Main Pass 98 field consists of Main Pass blocks 98 and 180. This field is located off the coast of Louisiana approximately 55 miles east of Venice in 91 feet of water. We acquired our 100% working interest in these blocks from NCX in 2009. The field produces from low relief, predominantly stratigraphically trapped sands located between two merging, generally south dipping faults. The productive interval is Middle Miocene Bigenerina Humblei. Cumulative field production through 2011 is approximately four MMBoe gross (21 Bcfe) gross. As of December 31, 2011, 11 wells have been drilled, of which seven have been successful. During December 2011, production from this field, net to our interest, averaged 371 Bbls of oil per day, 113 Bbls of NGLs per day and 5.4 MMcf of natural gas per day, for total production of 1.4 MBoe per day (8.3 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 2011 is approximately 144 MMBoe gross (861 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 2011, production from this field, net to our interest, averaged nine Bbls of oil per day and 6.4 MMcf of natural gas per day, for total production of 1.1 MBoe per day (6.4 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. Cumulative field production through 2011 is approximately 28 MMBoe gross (168 Bcfe gross). As of December 31, 2011, 18 wells have been drilled in this field, of which 14 were successful. During December 2011, production from this field, net to our interest, averaged 738 Bbls of oil per day, 227 Bbls of NGLs and 4.7MMcf of natural gas per day, for total production of 1.7 MBoe per day (10.5 MMcfe per day).

Proved Reserves

Our estimated proved reserves totaled 116.9 MMBoe (701.1 Bcfe) at December 31, 2011. The mix by product was 44% oil, 15% NGLs and 41% natural gas determined using the conversion ratio noted below. The conversion ratio does not assume price equivalency, and the price per Mcfe for natural gas, oil and NGLs may differ significantly from each other. Our proved reserves were estimated by NSAI, our independent petroleum consultant.

Our proved reserves are summarized below. These reserve amounts are consistent with filings we make with other federal agencies.

	As of December 31, 2011						
				Total Equivalent Reserves			
Classification of Proved Reserves (1)	**Oil (MMBbls)**	**NGLs (MMBbls)**	**Natural Gas (Bcf)**	**Oil Equivalent (MMBoe) (2)**	**Natural Gas Equivalent (Bcfe) (2)**	**% of Total Proved**	**PV-10 (3) (In millions)**
Proved developed producing	17.8	8.2	169.3	54.3	325.8	46%	$1,451.9
Proved developed non-producing	5.6	2.8	82.1	22.1	132.4	19%	527.1
Total proved developed	23.4	11.0	251.4	76.4	458.2	65%	1,979.0
Proved undeveloped	28.0	6.1	38.3	40.5	242.9	35%	1,112.9
Total proved	51.4	17.1	289.7	116.9	701.1	100%	$3,091.9

(1) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2011 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, 2011. Prices were adjusted by lease for quality, transportation, fees, energy content and regional price differentials. For oil, the West Texas Intermediate posted price was used in the calculation and, after adjustments, a price of $97.36 per Bbl was used in computing the amounts above. For NGLs, a ratio was computed for each field of the NGLs realized price compared to the oil realized price. Then, this ratio was applied to the oil price using SEC guidance. The NGLs price of $51.30 per Bbl was used in computing the amounts above. For natural gas, the average Henry Hub spot price was used in the calculation and the adjusted price of $4.11 per Mcf 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.

(2) Bcfe and MMBoe are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and NGLs may differ significantly from the price per Mcf for natural gas. Similarly, the price per Bbl for oil may differ significantly from the price per Bbl for NGLs.

(3) 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 and excludes ARO. PV-10 after ARO includes the present value of ARO related to proved reserves using a 10% discount rate and no inflation of current costs. Neither PV-10 nor 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 is as follows (in millions):

	As of December 31, 2011
Present value of estimated future net revenues (PV-10)	$3,091.9
Present value of estimated ARO, discounted at 10%	(339.9)
PV-10 after ARO	2,752.0
Future income taxes, discounted at 10%	(745.6)
Standardized measure of discounted future net cash flows	$2,006.4

Changes in Proved Reserves

Our total proved reserves increased to 116.9 MMBoe (701.1 Bcfe) at December 31, 2011 from 80.9 MMBoe (485.4 Bcfe) at December 31, 2010, primarily as a result of acquisitions discussed in Item 1, *Business,* which added 39.0 MMBoe (234.1 Bcfe) estimated as of the date of acquisition. Estimated proved reserves also increased 5.3 MMBoe (32.0 Bcfe) due to extensions and discoveries resulting from our participation in the drilling of 19 successful exploratory wells (gross) and increases resulting from well completions, recompletions and workovers. In addition, reserves increased from revisions of previous estimates by 8.6 MMBoe (51.0 Bcfe). Partially offsetting these increases were declines associated with production of 16.9 MMBoe (101.5 Bcfe). See *Financial Statements – Note 22 – Supplemental Oil and Gas Disclosures* under Part II, Item 8 in this Form 10-K for additional information.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2011 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 23 years and a member of the Society of Petroleum Engineers for over 27 years. He has over 34 years total experience in the oil and gas industry, with over 20 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. Our Vice President of Reservoir Engineering has served in that capacity since 2005, after having served as our Reservoir Engineering Manager since 2003 and has been with the Company since 1998. Prior to joining the Company, he served as a Reservoir and Facilities Engineer with Exxon and later as a Reservoir Engineer with Collarini Engineering, Inc. He received a Bachelor of Science degree in Civil Engineering from the University of Florida in 1977 and a Master of Science degree in Environmental Engineering from Tulane University in 1995.

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 Natural Gas and Natural Gas Liquids

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. We report all natural gas production information net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. In our December 31, 2011 reserve report prepared by our independent petroleum consultant, NGLs represented approximately 15% of our total proved reserves compared to 5% as of December 31, 2010. Due to the increase in the percentage for NGLs, we have reported NGLs separately from oil and have changed the presentation of prior periods for comparability. We convert Bbl to Mcfe using a ratio of six Mcf to one Bbl of oil, condensate or NGLs. This conversion ratio does not assume price equivalency and the prices on a volume equivalent basis may differ substantially between each other.

Development of Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2011, as estimated by our independent petroleum consultant, were 40.5 MMBoe (242.9 Bcfe). Future development costs associated with our proved undeveloped reserves at December 31, 2011 were estimated at $471.4 million. As of December 31, 2010, our proved undeveloped reserves were 15.7 MMBoe (94.1 Bcfe).

Our proved undeveloped reserves by field as of December 31, 2011 and 2010 are as follows:

	December 31, 2011		December 31, 2010	
	MMBoe	Bcfe	MMBoe	Bcfe
Main Pass 108	—	—	2.6	15.8
Ship Shoal 349 (Mahogany)	16.6	99.8	9.3	55.8
Mississippi Canyon 243	3.1	18.8	2.6	15.5
Viosca Knoll 823	1.4	8.2	1.2	7.0
Spraberry (Yellow Rose Properties)	19.4	116.1	—	—
Total	40.5	242.9	15.7	94.1

During 2011, we drilled three development wells at our Main Pass 108 field, only one of which resulted in the reclassification of proved undeveloped reserves to proved developed reserves. As shown in the table above, all of the proved undeveloped reserves associated with this field as of December 31, 2010 were either reclassified to proved developed or removed from our proved undeveloped reserves as of December 31, 2011.

During 2011, we drilled one development well and one exploration well at our Ship Shoal 349 (Mahogany) field. Also during the year, we had one well sand up that caused reserves previously classified as proved developed to be reclassified to proved undeveloped reserves. In addition, we decided to accelerate production from another well, which resulted in the movement of reserves previously classified as proved non-producing reserves to proved undeveloped reserves. We are currently drilling the third well of a potentially six well drilling program at the Mahogany field that commenced in 2011 and is expected to continue through 2013. This program is expected to result in the reclassification of a substantial portion of the proved undeveloped reserves to proved developed producing reserves in this field. Please see *Our Fields* above under this Item 2 for a description of our Mahogany field, which is our largest offshore field from a reserve standpoint.

The proved undeveloped reserves at our Mississippi Canyon 243 field and Viosca Knoll 823 fields were obtained through acquisitions completed in 2010 and development of both of these fields is expected to continue.

In May 2011, we acquired the Yellow Rose Properties, which contributed to a significant increase in proved undeveloped reserves between 2010 and 2011. Reserves for the Yellow Rose Properties as of December 31, 2011 consisted of 28.1 MMBoe (168.5 Bcfe), of which 19.4 MMBoe (116.1 Bcfe) was classified as proved undeveloped. See *Business* under Part I, Item 1, *Our Fields* in Item 2 above and *Financial Statements – Note 2 – Acquisitions* under Part II, Item 8 in this Form 10-K for additional information on the Yellow Rose Properties. In the Yellow Rose Properties, we completed 27 development wells and three exploration wells from the acquisition date of May 11, 2011 to December 31, 2011 and plan on drilling approximately 46 development wells in 2012.

We believe that we will be able to develop all of the reserves classified as proved undeveloped at December 31, 2011 within five years from the date such reserves were recorded. Our capital budget for 2012 is up 37% from our 2011 capital budget, with 61% dedicated to development activities, split 63% offshore and 37% onshore. The capital allocated to our offshore development activities will assist us in converting the proved undeveloped reserves at the Mahogany field to proved developed producing reserves. The expected expenditures for offshore development represent a significant increase over both 2010 and 2011 expenditures.

Acreage

The following summarizes our leasehold at December 31, 2011. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	605,083	369,967	61,164	61,164	666,247	431,131
Deepwater	85,952	50,470	40,320	31,680	126,272	82,150
Total Offshore	691,035	420,437	101,484	92,844	792,519	513,281
Onshore	17,599	16,282	187,631	157,152	205,230	173,434
Total	708,634	436,719	289,115	249,996	997,749	686,715

Approximately 82% of our total net offshore acreage is developed and approximately 9% of our total net onshore acreage is developed. We have the right to propose future exploration and development projects on the majority of our acreage.

For the offshore undeveloped leasehold, none of our rights will expire in 2012, 33,740 net acres (36%) could expire in 2013, 26,841 net acres (29%) could expire in 2014, 26,503 net acres (29%) could expire in 2015, and 5,760 net acres (6%) could expire in 2016 and beyond. For the onshore undeveloped leasehold, our rights to approximately 143,531 net acres (91%) could expire in 2012, 9,839 net acres (6%) could expire in 2013, 3,777 net acres (3%) could expire in 2014, and five net acres could expire thereafter. Of the undeveloped onshore leasehold, there are 140,885 net acres that can be extended by drilling two additional wells in 2012 and further extended by additional operations or production in future years. In making decisions regarding drilling and operations activity for 2012, we give consideration to undeveloped leasehold that may expire in the near term in order that we might retain the opportunity to extend such acreage.

Our net offshore acreage decreased 35,560 net acres (6%) from December 31, 2010 and our net onshore acreage increased 168,790 net acres from a minor ownership position as of December 31, 2010. The reduction in our net offshore acreage was attributable to certain offshore leases that terminated. This reduction was partially offset by the offshore property interests acquired in the Fairway Properties. The increase in our net onshore acreage is primarily attributable to the Yellow Rose Properties acquisition and leasehold interest acquired in East Texas.

Production

For the years 2011, 2010 and 2009, our net production averaged 278.2, 238.4 and 259.7 MMcfe per day, respectively. Production increased in 2011 from 2010 primarily due to acquisitions completed in 2010 and 2011 and the resumption of operations in certain fields that had been shut down from June 2010 to March 2011 due to pipeline outages. Production decreased in 2010 from 2009 primarily due to the two pipeline outages and divestitures completed in 2009, partially offset by acquisitions completed in 2010.

Production History

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

	Year Ended December 31,		
	2011	2010	2009
Net sales:			
Oil (MMBbls)	6.1	5.9	6.1
NGLs (MMBbls)	1.9	1.2	1.1
Natural gas (Bcf)	53.7	44.7	51.6
Total oil equivalent (MMBoe)	16.9	14.5	15.8
Total natural gas equivalent (Bcfe)	101.5	87.0	94.8

Refer to the descriptions of our ten largest fields reported earlier in this Item 2, *Properties,* for historical information about our produced volumes from our Spraberry field and Ship Shoal 349 field over the past three fiscal years, each of which have proved reserves exceeding 15% of our total proved reserves. Also refer to *Selected Financial Data – Historical Reserve and Operating Information* under Part II, Item 6 of this Form 10-K for additional historical operating data.

Productive Wells

The following presents our ownership interest at December 31, 2011 in our productive oil and natural gas wells. A net well is our percentage working interest of a gross well.

Offshore Wells

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	92	79	96	77	188	156
Non-operated	58	19	65	15	123	34
	150	98	161	92	311	190

Onshore Wells

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	111	111	1	1	112	112
Non-operated	—	—	—	—	—	—
	111	111	1	1	112	112

All Productive Wells

	Oil Wells (1)		Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	203	190	97	78	300	268
Non-operated	58	19	65	15	123	34
	261	209	162	93	423	302

(1) Includes eight gross (5.0 net) oil wells and seven gross (6.2 net) gas wells with multiple completions.

Drilling Activity

As presented in the tables below, our drilling activity increased in 2011 compared to 2010. Our onshore drilling activity increased due to the acquisition of the Yellow Rose Properties and additional leasehold interests acquired in Texas.

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, 2011, our capital expenditures for oil and natural gas properties and equipment of $719.0 million included $437.2 million for acquisitions, an adjustment for funds received of $5.7 million related to a 2010 acquisition, $77.6 million for exploration activities, $179.7 million for development activities and $30.2 million for seismic, capitalized interest and other leasehold costs.

In managing and tracking our drilling activity, we use target depth as the criteria to determine when a well is reported as drilled and use this criteria internally, in the field descriptions reported above and in press releases. This differs from the SEC's criteria of using completion to determine when a well is counted as drilled. Historically, the period between reaching target depth and completion has been relatively short for us. Using the completion criteria creates minor differences in reported wells drilled. For 2011, using target depth as the criteria, we had 54 total gross wells drilled. Using the SEC criteria of completion, we had 48 gross wells drilled. There was one well difference in 2010 and 2009 between the two criteria. The tables below are based on the SEC's criteria of completion to determine successful wells drilled.

Development Drilling

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

	Year Ended December 31,		
	2011	2010	2009
Gross Wells:			
Productive:			
Offshore	5	1	2
Onshore	27	—	—
Non-productive:			
Offshore	—	—	1
Onshore	—	—	—
	32	1	3
Net Wells:			
Productive:			
Offshore	4.5	0.1	1.7
Onshore	27.0	—	—
Non-productive:			
Offshore	—	—	0.3
Onshore	—	—	—
	31.5	0.1	2.0

Our success rates related to our gross development wells drilled during the years ended December 31, 2011, 2010 and 2009 were 100%, 100% and 67%, respectively.

Exploration Drilling

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

	Year Ended December 31,		
	2011	2010	2009
Gross Wells:			
Productive:			
Offshore	3	5	8
Onshore	12	—	—
Non-productive:			
Offshore	—	1	2
Onshore	1	2	—
	16	8	10
Net Wells:			
Productive:			
Offshore	2.4	3.6	6.4
Onshore	7.6	—	—
Non-productive:			
Offshore	—	1.0	1.3
Onshore	0.7	0.7	—
	10.7	5.3	7.7

Our success rates related to our gross exploration wells drilled during the years ended December 31, 2011, 2010 and 2009 were 94%, 63% and 80%, respectively.

Current Drilling Activity

The following table sets forth current 2012 drilling activity to February 17, 2012.

	January 1, 2012 to February 17, 2012	
	Development	Exploration
Gross Wells:		
Productive:		
Offshore	—	—
Onshore	4	8
Non-productive:		
Offshore	—	—
Onshore	—	—
	4	8
Net Wells:		
Productive:		
Offshore	—	—
Onshore	4	7.9
Non-productive:		
Offshore	—	—
Onshore	—	—
	4	7.9

As of February 17, 2012, we were in the process of drilling and/or completing one offshore development well, seven onshore exploration wells and eight onshore development wells.

Item 3. ***Legal Proceedings***

The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the EPA, has been conducting a federal grand jury investigation of environmental compliance matters relating to surface discharges and reporting on four of our offshore platforms in the Gulf of Mexico. We are fully cooperating with the investigation which began in 2011 and is continuing in 2012. The United States Attorney's Office has informed us that they are continuing their investigation with the intent to seek a criminal disposition. The outcome of this investigation could have a material adverse effect upon us. We are not able at this time to estimate our potential exposure, if any, related to this matter.

On May 6, 2009, certain Cameron Parish land owners filed suit in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and Tracy W. Krohn as well as several other defendants unrelated to us. In their lawsuit, plaintiffs are alleging that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and are seeking compensatory and punitive damages. We cannot currently estimate our potential exposure, if any, related to this lawsuit. We are currently, and intend to continue, vigorously defending this litigation.

From time to time, we are party to other litigation or legal and administrative proceedings that we consider to be a part of the ordinary course of our business. Except for the matters noted above, 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 (1)	Position
Tracy W. Krohn	57	Founder, Chairman, Director and Chief Executive Officer
Jamie L. Vazquez	51	President
John D. Gibbons	58	Senior Vice President, Chief Financial Officer and Chief Accounting Officer
Stephen L. Schroeder	49	Senior Vice President and Chief Operating Officer
Jesus G. Melendrez	53	Senior Vice President and Chief Commercial Officer
Thomas F. Getten	64	Vice President, General Counsel and Corporate Secretary

(1) Ages as of February 23, 2012.

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. During 1996 to 1997, Mr. Krohn was Chairman and Chief Executive Officer of Aviara Energy Corporation. Prior to founding the Company, from 1982 to 1983, Mr. Krohn was a senior engineer with Taylor Energy, and he began his career as a petroleum engineer and offshore drilling supervisor with Mobil Oil Corporation.

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. Prior to joining the Company, Ms. Vazquez was with CNG Producing Company for 17 years, holding positions of increasing responsibility ending as Manager, Land and Resource Development, Gulf of Mexico.

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. Prior to joining the Company, Mr. Schroeder was with Exxon USA for 12 years holding positions of increasing responsibility, ending with Offshore Division Reservoir Engineer.

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 Vice President, General Counsel and Assistant Secretary. In December 2011, Mr. Getten was appointed to the position of Corporate 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.

Item 4. ***Mine Safety Disclosures***

Not applicable.

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

	High	Low
2011		
First Quarter	$26.12	$17.51
Second Quarter	28.79	21.09
Third Quarter	29.27	13.74
Fourth Quarter	22.86	11.87
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

As of February 23, 2012, there were 229 registered holders of our common stock.

Dividends

Under the Credit Agreement, we are allowed to pay annual dividends up to $60 million per year if we are not in default. In addition, the indenture governing our 8.5% Senior Notes due in 2019 (the "8.5% Senior Notes") contains restrictions on the payment of dividends unless we meet certain restricted payment tests. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* under Part II, Item 7 and *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for more information regarding our Credit Agreement and the indenture governing the 8.5% 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
2011		
First Quarter	$ 2,979	$0.04
Second Quarter	2,979	0.04
Third Quarter	2,979	0.04
Fourth Quarter (1)	49,819	0.67
2010		
First Quarter	$ 2,240	$0.03
Second Quarter	2,241	0.03
Third Quarter	2,986	0.04
Fourth Quarter (2)	52,142	0.70

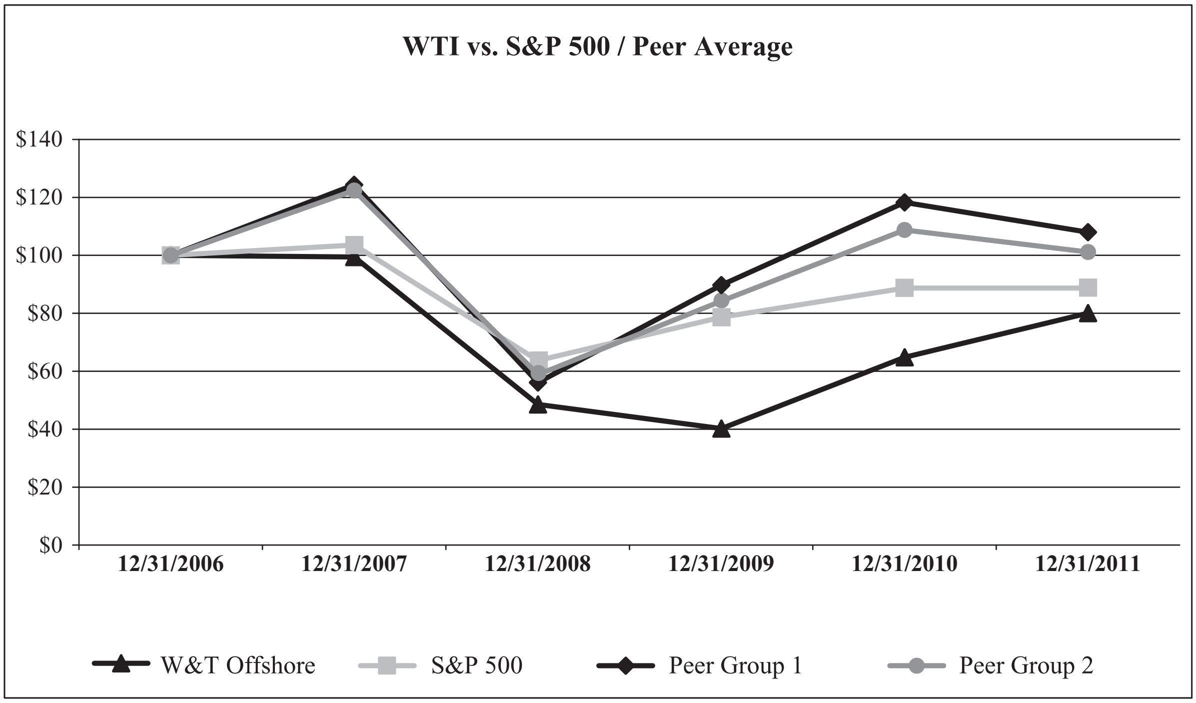
(1) Includes a regular dividend of $3.0 million ($0.04 per common share) and a special cash dividend of $46.9 million ($0.63 per common share).

(2) 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 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 February 23, 2012, our board of directors declared a cash dividend of $0.08 per common share, payable on March 30, 2012 to shareholders of record on March 14, 2012.

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 current peer group, Peer Group #2, is comprised of Apache Corporation, ATP Oil & Gas Corp., Bill Barrett Corp., Cabot Oil & Gas Corp., Comstock Resources, Inc., Energy XXI (Bermuda) Limited, Forest Oil Corp., McMoRan Exploration Co., Newfield Exploration Co., SM Energy Co., SandRidge Energy, Inc., Stone Energy Corp., and Swift Energy Company.

Our peer group used in the prior year, Peer Group #1, was 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 2011, 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, 2011 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, 2011 – October 31, 2011	N/A	N/A	N/A	N/A
November 1, 2011 – November 30, 2011	N/A	N/A	N/A	N/A
December 1, 2011 – December 31, 2011	108,714	$19.07	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 *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 and with *Financial Statements* in Part II, Item 8 in this Form 10-K.

	Year Ended December 31,				
	2011 (1)	**2010 (2)**	**2009**	**2008**	**2007**
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income (Loss) Information:					
Revenues:					
Oil	$643,222	$453,435	$ 365,411	$ 622,388	$ 495,545
NGLs	105,559	51,931	35,247	65,709	65,395
Natural gas	221,194	203,533	204,758	527,352	552,687
Other (3)	1,072	(3,116)	5,580	160	122
Total revenues (4)	971,047	705,783	610,996	1,215,609	1,113,749
Operating costs and expenses:					
Lease operating expenses (5)	219,206	169,670	203,922	229,747	234,758
Production taxes	4,275	1,194	1,544	8,827	5,921
Gathering and transportation	16,920	16,484	13,619	15,957	15,526
Depreciation, depletion and amortization	299,015	268,415	308,076	482,464	510,903
Asset retirement obligation accretion	29,771	25,685	34,461	39,312	22,007
Impairment of oil and natural gas properties (6)	—	—	218,871	1,182,758	—
General and administrative expenses	74,296	53,290	42,990	47,225	38,853
Derivative (gain) loss	(1,896)	4,256	7,372	16,464	36,532
Total costs and expenses	641,587	538,994	830,855	2,022,754	864,500
Operating income (loss)	329,460	166,789	(219,859)	(807,145)	249,249
Interest expense, net of amounts capitalized	42,516	37,706	40,087	34,709	37,088
Loss on extinguishment of debt (7)	22,694	—	2,926	—	2,806
Other income (8)	84	710	842	13,372	6,404
Income (loss) before income tax expense (benefit)	264,334	129,793	(262,030)	(828,482)	215,759
Income tax expense (benefit)	91,517	11,901	(74,111)	(269,663)	71,459
Net income (loss)	$172,817	$117,892	$(187,919)	$ (558,819)	$ 144,300
Earnings (loss) per common share					
Basic and diluted	$ 2.29	$ 1.58	$ (2.51)	$ (7.36)	$ 1.89
Dividends on common stock (9)	58,756	59,609	9,158	27,713	39,146
Cash dividends per common share (9)	0.79	0.80	0.12	0.36	0.51
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$521,478	$464,772	$ 156,266	$ 882,496	$ 688,597
Capital expenditures – oil and natural gas properties	719,026	415,653	276,134	774,879	361,235

	December 31,				
	2011	2010	2009	2008	2007
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 4,512	$ 28,655	$ 38,187	$ 357,552	$ 314,050
Total assets	1,868,925	1,424,094	1,326,833	2,056,186	2,812,204
Long-term debt	717,000	450,000	450,000	653,172	654,764
Shareholders' equity	544,574	421,743	358,950	572,227	1,151,340

(1) In the second quarter of 2011, we acquired the Yellow Rose Properties from Opal and, in the third quarter of 2011, we acquired the Fairway Properties from Shell.

(2) In the second quarter of 2010, we acquired the Matterhorn/Virgo Properties from Total and, in the fourth quarter of 2010, we acquired the Tahoe/Droshky Properties from Shell.

(3) Included in other revenues for 2010 is a reduction of $4.7 million due to a disallowance by the ONRR of royalty relief for transportation of deepwater production through our subsea pipeline system that was originally recorded in 2009. We are contesting this ONRR adjustment.

(4) Included in total revenues for 2010 is $24.9 million related to the recoupment of royalties paid to the ONRR in prior periods based on price thresholds that were believed to limit the availability of royalty relief on certain properties subject to the OCS Deepwater Relief Act of 1995.

(5) Included in lease operating expenses are net charges to expense for hurricane-related repairs netted with insurance reimbursements. For the years 2010, 2009, 2008 and 2007, the impact to lease operating expenses attributable to net hurricane – related expenses/reimbursements were $11.7 million decrease, $18.4 million increase, $17.7 million increase and $18.5 million increase, respectively, and there was no such impact to lease operating expenses in 2011.

(6) 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.

(7) In 2011, we expensed repurchase premiums, deferred financing costs and other costs totaling $22.0 million related to the repurchase of $450.0 million in aggregate principal amount of our 8.25% Senior Notes due 2014 (the "8.25% Senior Notes") and expensed $0.7 million of deferred financing costs related to replacement of our revolving bank credit facility. In 2009, we expensed $2.9 million of deferred financing costs related to the early repayment of our previously outstanding term loan facility ("Tranche B"). In 2007, we expensed $2.8 million of deferred financing costs related to the early repayment of our Tranche A term loan.

(8) Consists primarily of interest income.

(9) The years 2011, 2010, 2008 and 2007 include special dividends of $46.9 million ($0.63 per share), $49.2 million ($0.66 per share), $20.8 million ($0.39 per share) and $30.0 million ($0.27 per share), respectively. The year 2009 does not include 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 *Business* under Part I, Item 1 and *Properties* under Part I, Item 2 of the Form 10-K. The selected historical operating data set forth below should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 and with *Financial Statements* under Part II, Item 8 in this Form 10-K.

	December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Reserve Data:					
Estimated net proved reserves (1) (2):					
Oil (MMBbls)	51.4	34.0	31.2	40.0	46.4
NGLs (MMBbls)	17.1	4.2	3.0	3.9	4.6
Natural gas (Bcf)	289.7	256.3	165.8	227.9	332.8
Total oil equivalent (MMBoe)	116.9	80.9	61.8	81.9	106.5
Total natural gas equivalent (Bcfe)	701.1	485.4	371.0	491.1	638.8
Proved developed producing (Bcfe)	325.8	236.6	162.5	148.6	224.1
Proved developed non-producing (Bcfe) (3)	132.4	154.7	121.0	185.5	171.2
Total proved developed (Bcfe)	458.2	391.3	283.5	334.1	395.3
Proved undeveloped (Bcfe)	242.9	94.1	87.5	157.0	243.5
Proved developed reserves as a percentage of proved reserves	65.4%	80.6%	76.4%	68.0%	61.9%
Reserve additions (reductions) (Bcfe):					
Revisions (4)	51.1	20.2	(25.4)	(157.5)	(18.7)
Extensions and discoveries	32.0	29.2	23.4	47.2	48.4
Purchases of minerals in place	234.1	152.0	0.7	60.5	1.4
Sales of minerals in place	—	—	(24.0)	—	(1.0)
Production	(101.5)	(87.0)	(94.8)	(97.9)	(126.5)
Net reserve additions (reductions)	215.7	114.4	(120.1)	(147.7)	(96.4)

(1) Estimated reserves as of December 31, 2011, 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 and 2007 are based on end-of-period commodity prices in accordance with the previous SEC guidelines in effect on those respective dates.

(2) Bcfe and MMBoe are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs (totals may not compute 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 Bbl for oil for may differ significantly from the price per Bbl for NGLs.

(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.

(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,				
	2011	2010	2009	2008	2007
Operating Data:					
Net sales:					
Oil (MMBbls)	6.1	5.9	6.1	5.9	6.9
NGLs (MMBbls)	1.9	1.2	1.1	1.1	1.4
Oil and NGLs (MMBbls)	8.0	7.1	7.2	7.0	8.3
Natural gas (Bcf)	53.7	44.7	51.6	56.1	76.7
Total oil equivalent (MMBoe)	16.9	14.5	15.8	16.3	21.1
Total natural gas equivalent (Bcfe)	101.5	87.0	94.8	97.9	126.5
Average daily equivalent sales (MBoe/d)	46.4	39.7	43.3	44.6	57.8
Average daily equivalent sales (MMcfe/d)	278.2	238.4	259.7	267.5	346.7
Average realized sales prices (Unhedged):					
Oil ($/Bbl)	$105.92	$77.33	$59.96	$105.74	$71.89
NGLs ($/Bbl)	55.81	43.65	31.96	60.62	46.45
Oil and NGLs ($/Bbl)	94.02	71.65	55.67	98.72	67.58
Natural gas ($/Mcf)	4.12	4.55	3.97	9.40	7.20
Oil equivalent ($/Boe)	57.32	48.87	38.32	74.50	52.81
Natural gas equivalent ($/Mcfe)	9.55	8.15	6.39	12.42	8.80
Average realized sales prices (Hedged) (1):					
Oil ($/Bbl)	$104.30	$77.05	$59.96	$100.94	$71.20
NGLs ($/Bbl)	55.81	43.65	31.96	60.62	46.45
Oil and NGLs ($/Bbl)	92.78	71.42	55.67	94.67	67.01
Natural gas ($/Mcf)	4.12	4.71	3.96	9.42	7.28
Oil equivalent ($/Boe)	56.74	49.25	38.30	72.82	52.87
Natural gas equivalent ($/Mcfe)	9.46	8.21	6.38	12.14	8.81
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 2.16	$ 1.95	$ 2.15	$ 2.35	$ 1.86
Gathering and transportation costs	0.17	0.19	0.14	0.16	0.12
Production costs	2.33	2.14	2.29	2.51	1.98
Production taxes	0.04	0.01	0.02	0.09	0.05
Depreciation, depletion, amortization and accretion	3.24	3.38	3.61	5.33	4.21
General and administrative expenses	0.73	0.61	0.45	0.48	0.31
	$ 6.34	$ 6.14	$ 6.37	$ 8.41	$ 6.55
Total number of wells drilled (gross):					
Offshore	8	7	13	25	9
Onshore	40	2	—	—	—
Total number of productive wells drilled (gross):					
Offshore	8	6	10	19	8
Onshore	39	—	—	—	—

(1) Data for all years presented includes the effects of realized 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 *Financial Statements* under Part II, Item 8 of this Form 10-K. 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 Form 10-K.

Overview

We are an independent oil and natural gas producer focused primarily in the Gulf of Mexico and Texas. We have grown through acquisitions, exploration and development and currently hold working interests in approximately 58 producing and two capable of producing offshore fields in federal and state waters. During 2011, we expanded onshore into West Texas and East Texas through an acquisition and acquiring interests in leasehold acreage. We have interests in offshore leases covering approximately 0.8 million gross acres (0.5 million net acres) spanning primarily across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama and 0.2 million gross acres (0.2 million net acres) onshore in Texas. We operate wells accounting for approximately 80% of our average daily production. We own interests in approximately 253 offshore structures, 158 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 increasing production and reserves at a profit. We strive to grow our reserves and production 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 2011, we closed on two acquisition transactions. On May 11, 2011, we completed the acquisition from Opal of the Yellow Rose Properties, which consists of approximately 24,500 gross acres (21,900 net acres) of oil and gas leasehold interests in the Permian Basin of West Texas. Based on internal estimates, proved reserves associated with the Yellow Rose Properties as of the acquisition date were approximately 30.1 MMBoe (180.4 Bcfe), comprised of approximately 69% oil, 22% NGLs and 9% natural gas, and approximately 70% of which were classified as proved undeveloped. The stated purchase price was $366.3 million, subject to certain adjustments, including adjustments from an effective date of January 1, 2011 until the closing date of May 11, 2011. Taking into account such adjustments, the adjusted purchase price was $394.4 million. The increase of $28.1 million primarily reflects drilling and development costs in excess of cash flow from the effective date of January 1, 2011 to the closing date. We assumed the ARO, which we have estimated to be $0.4 million, and recorded a long-term liability of $2.1 million. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

On August 10, 2011, we completed the acquisition of the Fairway Properties, which consist of Shell's 64.3% working interest in the Fairway Field along with a like interest in the associated Yellowhammer gas treatment plant. Based on internal estimates, proved reserves associated with the Fairway field as of the acquisition date were 8.9 MBoe (53.5 Bcfe) comprised of approximately 72% natural gas, 27% NGLs and less than 1% oil and which are 100% proved developed. The stated purchase price was $55.0 million, subject to certain adjustments, including adjustments from an effective date of September 1, 2010 until the closing date. Taking into account such adjustments, as of December 31, 2011, the purchase price was reduced to $42.9 million. The decrease of $12.1 million primarily reflects net production cash flow, partially offset by plugging and abandonment and other operating costs incurred, from the effective date of September 1, 2010 to the closing date. The purchase price is subject to further post-effective date adjustments and final settlement is expected to occur in the first half of 2012. We assumed the ARO associated with the properties and plant, which we have estimated to be $7.8 million. The acquisition was funded from borrowings under our revolving bank credit facility.

During the year 2010, we closed on two acquisition transactions. The first was on April 30, 2010, when we acquired all of Total's interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico. Estimates of proved reserves as of the acquisition date were 10.9 MBoe (65.6 Bcfe) comprised of approximately 58% oil, 6% NGLs and 36% natural gas and which are 69% proved developed. The adjusted purchase price was $121.3 million inclusive of the ARO estimated at $6.3 million. The acquisition was funded with cash on hand.

The second acquisition in 2010 was on November 3, 2010, when we acquired all of Shell's interests, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico. Estimates of proved reserves as of the acquisition date were 13.3 MBoe (80.0 Bcfe) comprised of approximately 8% oil, zero NGLs and 92% natural gas and which are 100% proved developed. The adjusted purchase price was $134.2 million inclusive of the ARO estimated at $18.0 million. The acquisition was funded with cash on hand.

See *Financial Statements – Note 2 – Acquisitions* under Part II, Item 8 of this Form 10-K for additional information on acquisitions.

From time to time, as part of our business strategy, we sell various properties that we consider non-core assets. We did not sell any properties in 2011 and 2010. We are currently marketing a package of non-core properties located on the OCS.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil, NGLs and natural gas production and the prices that we receive for such production. Our production volumes for 2011 were comprised of approximately 36% oil and condensate, 11% NGLs and 53% natural gas, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs. The conversion ratio does not assume price equivalency, and the prices per Mcfe for oil, NGLs and natural gas may differ significantly. For 2011, our combined total production of oil, NGLs and natural gas was approximately 16.7% higher on a Mcfe basis than during the same period in 2010.

The third-party pipeline used by our Main Pass 108 and 98 fields was shut down from June 2010 to March 2011. This impacted our production in 2011 and in 2010. By the end of the second quarter of 2011, production had been restored and has been positively impacted by various workover activities and significant field work, which included drilling both an exploration well and three development wells. In December 2011, these fields produced approximately 33.4 MMcfe per day, made up of 815 Bbls of oil per day, 538 Bbls of NGLs per day and 25.3 MMcf of natural gas per day.

During 2011, prices for oil were volatile and increased significantly compared to 2010. The majority of our oil production is priced using the posted spot price for West Texas Intermediate ("WTI") as a base price plus a premium depending on the type of crude oil. WTI is frequently used to value domestically produced crude oil. Most of our oil production is from our offshore oil production, which is comprised of various crudes including Light Louisiana Sweet, Heavy Louisiana Sweet and Poseidon. Starting in the first quarter of 2011 and continuing through the end of 2011, these various crudes sold at a significant premium relative to WTI. In 2011 compared to 2010, our realized oil sales price (unhedged) increased 37.0%, compared to a 19.4% increase in the unweighted average daily posted spot price for WTI. The majority of our crude prices have correlated closer to the international oil market prices, as measured using the unweighted average daily posted spot price for Brent crude, which increased 39.8% in 2011.

The premiums received on our offshore oil production have been up to $30.00 per Bbl during times in 2011. In comparison, the average premium spread between Heavy Louisiana Sweet crude and WTI crude was approximately $2.00 per Bbl during 2010 and the average premium spread between Light Louisiana Sweet crude and WTI crude was approximately $3.00 per Bbl during 2010. According to industry sources, the correlation between North Sea Brent crude oil and WTI, the crude that trades on the New York Mercantile Exchange ("NYMEX"), had historically been extremely high. In fact, in the past, Brent crude oil has traded at a discount to WTI as Brent crude oil is a lower quality relative to WTI. In the middle of November of 2011, that correlation between the two crudes had fallen to its lowest level in twenty years. At the beginning of 2011, the price of crude oil at Cushing, Oklahoma, which is where the NYMEX WTI crude is priced, was pressured by an over supply situation. On the other hand, Brent prices were aided by supply disruptions due to unrest in the Middle East and oil production was halted in Libya. Since that time, the turmoil in Europe reduced oil demand and Libya's oil production is returning. In addition, the announced reversal of the Seaway pipeline that has taken crude oil from the Gulf Coast to Cushing will begin flowing crude oil in Cushing to the Gulf Coast beginning in mid-2012. The price spread between Brent crude oil and WTI narrowed significantly on the day of this announcement. More recently, both WTI and Brent crude oil prices have increased with threats by Iran of closing the Strait of Hormuz and the implications of significantly reducing crude oil supplied from the region. If economic growth continues in China, India, Brazil and Russia, such activity will support strong crude oil prices. Also supporting higher prices is the fact that economic deterioration in the US and other countries has forced countries to adopt potentially inflationary policies which may raise the price of hard assets like crude oil and gold.

Natural gas prices are much more affected by domestic issues, such as supply, local demand issues and domestic economic conditions. During 2011, our average realized sales price of natural gas (unhedged) decreased 9.5% from 2010 compared to the benchmark Henry Hub unweighted average daily posted spot price, which decreased 8.5% from 2010. We expect continued weakness in natural gas prices at least through 2012 as producers continue to drill to hold leases, natural gas storage levels continue at record highs, winter weather continues to be relatively mild, production of natural gas as a by product of the substantial ramp up of oil drilling continues and production efficiency gains are achieved in the shale gas areas resulting from better fracking techniques. Potential mitigating factors could include an increase in demand if the United States experiences a strong economic recovery, a dramatic decrease in drilling activity, including horizontal oil well drilling, (which isn't likely at current high oil prices) or production shut-ins due to economic factors. According to Baker Hughes data, the number of rigs drilling for oil has more than tripled since the beginning of 2009. 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, use of directed horizontal drilling rigs is at record levels and is up over 20% in January 2012 compared to January 2011, while the total oil rig count is up over 50% in January 2012 compared to January 2011.

In 2011 and 2010, we did not incur an impairment write-down. Due to declines in oil, NGL and natural gas prices, in 2009 we recorded an impairment write-down of $218.9 million, as determined through the application of the ceiling test.

Should prices decline for oil and natural gas in the future, our future oil, NGL and natural gas revenues, earnings and liquidity would be negatively impacted, and could result in impairment write-downs of the carrying value of our oil and natural gas properties. This decline could create issues with financial ratio compliance, and could result in a reduction of the borrowing base associated with our credit agreement, depending on the severity of such declines. If those factors were to occur and were significant, the willingness of financial institutions and investors to provide capital to us and others in the oil and natural gas industry in the future could be impacted.

Our operating costs include the expense of operating our wells, platforms and other infrastructure primarily in the Gulf of Mexico and Texas and transporting our production 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.

Revenue from our production is highly dependent on pipelines owned by others to access markets for our products. To the extent that the transportation price such pipelines charge increases, our revenues from the sales of our products would go down or transportation costs would increase, the result of either would be a reduction in operating income. Certain pipelines have filed tariffs which may increase the amounts charged to us and we believe that we have limited alternatives to use other pipelines. The approval process typically results in approval of fees less than those contained in the filing requests; therefore, at this time, we are unable to determine whether or when the rates may ultimately be increased and are unable to estimate the impact to operating income in 2012.

In recent years, we acquired and built platforms near the outer edge of the continental shelf and operated 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 from 2008 through 2011 for hurricane related damage occurring in 2008 and expect to incur costs through 2013 to complete plugging and abandonment work primarily related to three toppled platforms. We received reimbursements from our insurance carrier in each of the last three years and expect to receive additional reimbursements for covered costs incurred in future periods as covered costs incurred to date have not exceeded policy limits. See *Liquidity and Capital Resources* below and *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims* under Part II, Item 8 in this Form 10-K 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 and in the deepwater. We generally do not pre-fund our ARO. We estimated the present value of our liability related to our ARO at $393.9 million as of December 31, 2011. 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 expenditure, and changes in the legal, regulatory, environmental and political environments. Actual expenditures for ARO could vary significantly from these estimates.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in the deep water of the Gulf of Mexico which caused loss of life, caused the rig to sink and created a major oil spill that produced economic, environmental and natural resource damage. Subsequently, the BOEM issued a series of NTLs and other significant changes in regulations and implemented a six-month moratorium on drilling activities which began in May 2010. After the drilling moratorium ended in November 2010, it was not until March 2011 that deep water drilling permits began to be issued, and even then only sporadically, to continue drilling activities that had commenced prior to the Deepwater Horizon incident. Since March 2011, deepwater drilling permits have been issued, albeit at a slower and much more measured pace than before the Deepwater Horizon event. The most significant regulatory changes since the Deepwater Horizon event are regulations related to assessing the potential environmental impact of future spills using worse case discharge scenarios on a well-by-well basis, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental management system. The new regulations and increased review process increases the time it takes to obtain drilling permits and increases the cost of operations. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time. The permitting process is also slow and inconsistent for shallow water work and even for plug and abandonment activities. This could lead to increased costs and performing work at less than optimal effectiveness or even at less than desirable times due to weather. We have not experienced delays in obtaining permits related to our onshore operations.

Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Revenues. Total revenues increased $265.3 million, or 37.6%, to $971.0 million in 2011 compared to 2010. Oil revenues increased $189.8 million, NGLs revenues increased $53.6 million, natural gas revenues increased $17.7 million and other revenues increased $4.2 million. The oil revenue increase was attributable to a 37.0%

increase in the average realized sales price (unhedged) to $105.92 per Bbl in 2011 from $77.33 per Bbl in 2010, combined with an increase of 3.4% in sales volumes. The NGLs revenue increase was attributable to a 27.9% increase in the average realized sales price (unhedged) to $55.81 per Bbl in 2011 from $43.65 per Bbl in 2010, combined with an increase of 58.3% in sales volumes. The sales volume increase for oil and NGLs is primarily attributable to increases associated with properties acquired in 2011 and 2010. The increase in natural gas revenue resulted from a 20.1% increase in sales volumes, partially offset by a 9.5% decrease in the average realized natural gas sales price (unhedged). For 2011, the natural gas average realized sales price was $4.12 per Mcf compared to $4.55 per Mcf for 2010. The sales volume increase for natural gas is primarily attributable to increases associated with our acquisition activities, the Main Pass 108 fields resuming production and successful exploration efforts. Other revenue changed primarily due to a disallowance of $4.7 million by the ONRR in 2010 of royalty relief for transportation of deepwater production through our subsea pipeline system. *We are* contesting this ONRR adjustment. For additional information, see *Financial Statements – Note 19 – Contingencies* under Part II, Item 8 of this Form 10-K.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance, workovers, maintenance on our facilities, and hurricane remediation costs net of insurance claims, increased $49.5 million to $219.2 million in 2011 compared to 2010. On a per Mcfe basis, lease operating expenses increased to $2.16 per Mcfe during 2011compared to $1.95 per Mcfe during 2010. On a component basis, base lease operating expenses, facility expenses, hurricane remediation costs net of insurance claims, and workover costs increased $20.7 million, $14.1 million, $11.7 million and $3.6 million, respectively. As a partial offset, insurance premiums decreased $0.6 million. The increase in base lease operating expenses is primarily attributable to expenses associated with the properties acquired in 2011 and 2010, higher costs at our various non-operated properties and increased processing fees associated with our Daniel Boone field production. The increase in facility expenses is primarily attributable to work performed on the tendon tension monitoring system and mechanical repairs at our Matterhorn platform, the pipeline repairs at our Ship Shoal 300 field to remove paraffin and inspection fees at our Main Pass 252 platforms. Hurricane remediation costs net of insurance claims increased primarily due to higher reimbursements received in 2010. Workover costs increased due to work performed at our Yellow Rose Properties and expenses at the Main Pass 108 field, partially offset by projects in 2010 that did not occur in 2011. The decrease in insurance premiums resulted primarily from lower premiums on our insurance policies covering well control and hurricane damage that cover the policy period June 1, 2010 to June 1, 2011. Our premiums increased effective with the June 1, 2011 renewal attributable to a substantial improvement in coverage. For additional information, see *Liquidity and Capital Resources – Hurricane Remediation and Insurance Claims.*

Production taxes. Production taxes increased to $4.3 million during 2011 compared to $1.2 million in 2010 primarily due to the Yellow Rose Properties and the Fairway Properties' operations and are currently not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

Gathering and transportation costs. Gathering and transportation costs were basically flat for 2011 compared to the prior year.

Depreciation, depletion, amortization and accretion ("DD&A"). DD&A, including accretion for ARO, decreased to $3.24 per Mcfe for 2011 from $3.38 per Mcfe for 2010. On a nominal basis, DD&A increased to $328.8 million for 2011 from $294.1 million in 2010. The decrease in DD&A on a per Mcfe basis was primarily due to increases in proved reserves while DD&A on a nominal basis increased due to higher production volumes.

General and administrative expenses. G&A increased to $74.3 million for 2011 from $53.3 million for 2010 due to a number of factors including higher incentive compensation as a result of improved financial and operational performance, costs related to expanded onshore and offshore activities, acquisitions, surety premiums, transition services fees paid to the sellers of the acquired properties, and litigation related costs. Also, we earned administration fees in 2010 related to an asset disposition, and no such fees were earned in 2011. On a per Mcfe basis, G&A was $0.73 per Mcfe for 2011, compared to $0.61 per Mcfe for 2010. See *Financial Statements – Note 11 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 of this Form 10-K for additional information.

Derivative (gain) loss. For 2011, our derivative gain of $1.9 million was attributable entirely to a change in the fair value of our commodity derivatives as a result of the changes in crude oil prices. For 2010, our derivative loss of $4.3 million was attributable to a loss from our commodity derivatives of $4.0 million and a loss of $0.3 million related to our interest rate swap. See *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K for additional information.

Interest expense. Interest expense incurred increased to $52.4 million for 2011 from $43.1 million for 2010. During 2011, the amounts outstanding of our senior notes increased to $600.0 million from $450.0 million due to issuing our 8.5% Senior Notes and repurchasing our 8.25% Senior Notes. During 2011 and 2010, $9.9 million and $5.4 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties which increased due to the Yellow Rose Properties acquisition. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information.

Loss on extinguishment of debt. The loss on extinguishment of debt during 2011 of $22.7 million was attributable primarily to the repurchase of all of the $450.0 million outstanding of our 8.25% Senior Notes. The repurchase of the 8.25% Senior Notes was funded with a portion of the proceeds from the issuance of the 8.5% Senior Notes. The call premiums, unamortized debt issuance costs and other related expenses totaled $22.0 million. In addition, the previous revolving bank credit facility was amended and the termination date extended resulting in the write off of unamortized debt issuance costs of $0.7 million. In 2010, no loss on extinguishment of debt was incurred. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information.

Interest income. Interest income decreased to $0.1 million for 2011 from $0.7 million in 2010 primarily due to lower average daily cash balances and a reduction in market interest rates received on invested cash in 2011.

Income tax expense (benefit). Income tax expense increased to $91.5 million for 2011 compared to $11.9 million for 2010. Our effective tax rate for 2011 was 34.6% and differed from the federal statutory rate of 35% primarily as a result of the deduction for qualified domestic production activities under Section 199 of the Internal Revenue Code ("IRC"). Our effective tax rate for 2010 was 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 IRC. Taxable income in 2010 allowed us to reverse all of our previously recorded valuation allowance.

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 2010 compared to 2009. Oil revenues increased $88.0 million, NGLs revenues increased $16.7 million, natural gas revenues decreased $1.2 million and other revenues decreased $8.7 million. The oil revenue increase was caused by a 29.0% increase in the average realized oil price (unhedged) to $77.33 per Bbl in 2010 from $59.96 per Bbl in 2009, partially offset by a 3.3% decrease in sales volumes to 5.9 MMBbls in 2010 from 6.1 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 NGLs revenue increase was attributable to a 36.6% increase in the average realized sales price (unhedged) to $43.65 per Bbl in 2010 from $31.96 per Bbl in 2009, combined with an increase of 9.1% in sales volumes. The sales volume increase for NGLs was primarily attributable to acquisitions. 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 (unhedged) 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 ONRR of royalty relief for transportation of deepwater production through our subsea pipeline system. We are contesting this ONRR adjustment.

Lease operating expenses. Lease operating expenses decreased $34.3 million to $169.7 million in 2010 compared to the prior year. On a Mcfe basis, lease operating expenses decreased to $1.95 per Mcfe in 2010 from $2.15 per Mcfe in 2009. On a component basis, hurricane remediation costs net of insurance claims, 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 net of insurance claims decreased due to insurance reimbursements being in excess of cost incurred for 2010. 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. The decrease in insurance expense is attributable to lower insurance premiums 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, partially offset by property divestitures that occurred in 2009.

Depreciation, depletion, amortization and accretion. DD&A, including accretion for ARO, decreased to $3.38 per Mcfe in 2010 from $3.61 in 2009. On a nominal basis, DD&A decreased to $294.1 million in 2010 from $342.5 million in 2009. The rate per Mcfe is lower primarily due to the reserves acquired and the property divestitures in 2009 while DD&A on a nominal basis decreased primarily due to lower production and the lower rate per Mcfe.

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 *Financial Statements – Note 1 – Significant Accounting Policies* under Part II, Item 8 of this Form 10-K.

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 *Financial Statements – Note 11 – Share-Based and Cash-Based Incentive Compensation* under Part II, Item 8 of this Form 10-K for additional 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. See *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K for additional information.

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 primarily 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 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 IRC. Taxable income in 2010 allowed us to reverse all of our previously recorded valuation allowance. For 2009, the income tax benefit resulted from a pre-tax loss. Our effective tax rate for 2009 was 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.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings and make related interest payments and pay dividends. We have funded such activities with cash on hand, cash provided by operating activities, 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 for 2011 was $521.5 million, compared to $464.8 million for 2010. The 2010 period included income tax refunds of $99.8 million primarily related to the Worker, Homeowner and Business Assistance Act of 2009 that allowed us to carry back losses to previously closed years, while the 2011 period included tax payments of $35.7 million. Otherwise, cash flow from operating activities increased $192.2 million due to substantially improved operating results. Our combined average realized sales price per Mcfe was 17.2% higher than the comparable 2010 period and our combined production of oil, NGLs and natural gas on a Mcfe basis during 2011 was 16.7% higher than 2010.

Net cash used in investing activities during 2011 and 2010 was $722.7 million and $415.0 million, respectively, which primarily represents our investments in oil and natural gas properties. Cash used in investing activities in 2011 consisted primarily of the consideration for the acquisitions of the Yellow Rose Properties ($394.4 million) and the Fairway Properties ($42.9 million). In 2010, cash used in investing activities primarily consisted of the consideration for the acquisition of the Matterhorn/Virgo properties ($115.0 million) and the Tahoe/S. Tahoe/Droshky properties ($121.9 million). In addition, investments in other oil and natural gas properties and equipment were $281.8 million in 2011 compared to $178.7 million in 2010 with the increase primarily related to the Yellow Rose Properties. There were minimal proceeds from sales of assets in 2011 and proceeds from asset sales were $1.4 million for 2010.

Net cash provided by financing activities was $177.1 million during 2011. Funds were provided through net borrowings on the revolving bank credit facility of $117.0 million and issuance of $600.0 million of 8.5% Senior Notes and partially offset by the repurchase of $450.0 million of the 8.25% Senior Notes, repurchase premium and debt issuance costs of $32.3 million and the payment of dividends of $58.8 million, which includes a special dividend of $46.9 million. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information on the senior note transactions. Net cash used in financing activities during 2010 was $59.3 million, which reflects dividend payments including a special dividend of $49.2 million.

At December 31, 2011, we had a cash balance of $4.5 million and $457.6 million of undrawn capacity available under the revolving bank credit facility which had a borrowing base of $575.0 million as of December 31, 2011.

Credit agreement and long-term debt. At December 31, 2011, $117.0 million was outstanding under our revolving bank credit facility compared to zero at December 31, 2010. At December 31, 2011, $600.0 million of our 8.5% Senior Notes was outstanding and at December 31, 2010, $450.0 million was outstanding of our 8.25% Senior Notes. We believe that cash provided by operations, borrowings available under our revolving bank credit facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements.

On May 5, 2011, we entered into our amended Credit Agreement, which provides a revolving bank credit facility with an initial borrowing base of $525.0 million collateralized by our oil and natural gas properties. The borrowing base was re-determined in October 2011 and was increased to $575.0 million. The Credit Agreement terminates on May 5, 2015. Fees and transactions costs related to the Credit Agreement were approximately $6.1 million and are included in the repurchase premium and debt issuance costs discussed above. 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 evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the size of our revolving bank credit facility.

We currently have 10 lenders within the revolving bank credit facility, with commitments ranging from $35.0 million to $68.0 million for the current borrowing base of $575.0 million. While we have not experienced, nor do we anticipate, any difficulties in obtaining funding from any of these lenders at this time, any lack of or delay in funding by members of our banking group could negatively impact our liquidity position.

Borrowings under the revolving bank credit facility bear interest at the applicable London Interbank Offered Rate or LIBOR, plus applicable margins ranging from 2.00% to 2.75%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, and (c) LIBOR plus 1%, plus applicable margins ranging from 1.00% to 1.75%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%.

The Credit Agreement contains covenants that restrict, among other things, the payment of cash dividends in excess of $60.0 million per year, common stock repurchases and Senior Note repurchases in excess of $100 million in the aggregate, borrowings other than from the revolving bank credit facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. The Credit Agreement contains various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2011. During 2011, borrowings outstanding on the revolving bank credit facility increased to $300.0 million primarily to fund the acquisition of the Yellow Rose Properties, which also included funding from cash on hand. These borrowings were subsequently reduced to $117.0 million as of December 31, 2011, primarily by utilizing funds received from the senior note transactions described below and net cash from operations, partially offset by capital expenditures and dividends. Letters of credit outstanding as of December 31, 2011 were $0.4 million.

On June 10, 2011, we issued $600.0 million of 8.5% Senior Notes and used a portion of the net proceeds to repurchase the $450.0 million outstanding of our 8.25% Senior Notes. The net cash provided by these senior notes transactions, which includes initial purchaser fees, redemption premiums and other transactions costs, was $123.8 million. These transactions extended the maturity date of our long-term debt and we used the net proceeds to pay down a portion of amounts outstanding under the revolving bank credit facility. The 8.5% Senior Notes mature on June 15, 2019. Interest is payable semi-annually in arrears on June 15 and December 15 of each year beginning on December 15, 2011. See *Financial Statements – Note 7 – Long-Term Debt* under Part II, Item 8 of this Form 10-K for additional information about our Credit Agreement and long-term debt.

From time to time, we use various derivative instruments to manage a portion of our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of December 31, 2011, our outstanding derivative instruments consisted of commodity swap and option contracts relating to approximately 2.2 MMBbls, 1.3 MMBbls and 0.7 MMBbls of our anticipated oil production for 2012, 2013 and 2104, respectively. See *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K for additional information about our derivatives.

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 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 facilities we chose not to insure) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention requirement of $10 million per occurrence. In 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. The damage we incurred as a result of Hurricane Gustav was 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, which arises when our insurance underwriters' adjuster reviews and approves such costs for payment by the underwriters. Claims that have been processed in this manner have customarily been paid on a timely basis.

In 2011, 2010, 2009 and 2008 we have received cash of $20.9 million, $65.5 million, $47.1 million and $5.8 million, respectively, from our insurance carrier related to Hurricane Ike claims (totaling $139.3 million) and have recorded $0.7 million of insurance receivables as of December 31, 2011 for claims that have been submitted and approved for payment. As of December 31, 2011, we have recorded in ARO an estimate of $56.9 million for additional costs to be incurred related to Hurricane Ike and we have estimated that this work will be completed by the end of 2013. 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 Hurricane Ike, 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 bank credit facility will be sufficient to meet these future cash needs.

For a discussion of our hurricane remediation costs related to lease operating expenses incurred during 2011, 2010 and 2009, refer to *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims* under Part II, Item 8 of this Form 10-K. Lease operating expenses will be offset in future periods to the extent that these costs incurred are approved for payment under our insurance policies. We expect that the majority of insurance reimbursements subsequent to December 31, 2011 will be attributable to plugging and abandonment activities.

We currently carry three layers of insurance coverage for our operating activities in the Gulf of Mexico. The current policy limits for well control and hurricane damage (defined as named windstorm in our policies) are up to $100.0 million and $120.0 million, respectively, and the policies are effective until June 1, 2012. We carry an additional $100.0 million of well control coverage effective until June 1, 2012 on certain wells at our Mahogany, Matterhorn, Virgo, Tahoe and SE Tahoe fields. A retention amount of $5.0 million for well control events and $37.5 million per hurricane 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. As of December 31, 2011, approximately 93% of our PV-10 value of proved reserves attributable to our Gulf of Mexico properties are on platforms that are covered under our current insurance policies for named windstorm damage. Pollution causing a negative environmental impact is characterized as a covered component of each of the well control and hurricane sections of the policy.

Our general and excess liability policy, which is effective until May 1, 2012, provides for $250.0 million of liability coverage for bodily injury and property damage, including liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility ("OSFR") requirement under the OPA, we are required to evidence $150.0 million of financial responsibility to the BSEE. We qualify to self-insure for $35 million of this amount and the remaining $115.0 million is covered by insurance.

The premiums for the above policies were $30.7 million for the May/June 2011 policy renewals compared to $22.6 million for the expiring policies. The increase in our premiums effective with the June 1, 2011 renewal was primarily attributable to an increase in the policy limit for hurricane damage and increases in covered property. Although we have not been informed otherwise, in the future, 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 there could be an 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 claims, 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,		
	2011	2010	2009
		(in thousands)	
Acquisition of Yellow Rose Properties	$394,377	$ —	$ —
Acquisition of Fairway Properties	42,870	—	—
Acquisition of (adjustments to) Tahoe/Droshky Properties	(5,700)	121,933	—
Acquisition of Matterhorn/Virgo Properties	—	115,012	—
Exploration (1)	77,606	60,164	90,636
Development (1)	179,705	77,230	162,111
Seismic, capitalized interest, other leasehold costs	30,168	41,314	23,387
Acquisitions and investments in oil and gas property/equipment	$719,026	$415,653	$276,134

(1) Reported by geography in the subsequent table.

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Conventional shelf	$132,680	$115,503	$200,699
Deepwater	4,826	9,358	45,911
Deep shelf	5,833	3,382	4,573
Onshore	113,972	9,151	1,564
Exploration and development capital expenditures	$257,311	$137,394	$252,747

The following table sets forth our drilling activity on a gross basis.

	Successful			Unsuccessful		
	2011	2010	2009	2011	2010	2009
Offshore – gross wells drilled:						
Conventional shelf	7	6	8	—	1	3
Deep shelf	1	—	2	—	—	—
Wells operated by W&T	7	3	7	n/a	n/a	n/a
Onshore:						
Gross wells drilled	40	—	—	1	2	—
Wells operated by W&T	33	—	—	n/a	n/a	n/a

As of December 31, 2011, we were in the process of drilling and/or completing seven onshore development wells in Texas, 13 onshore exploration wells in Texas and no offshore wells.

See *Properties – Drilling Activity* under Part I, Item 2 of this Form 10-K for a breakdown of exploration and development wells and additional drilling activity information.

See *Properties – Development of Proved Undeveloped Reserves* under Part I, Item 2 of this Form 10-K for a discussion on activity related to proved undeveloped reserves.

In 2011, we did not participate in bidding for any Gulf of Mexico leases on the OCS. Due to the government mandated moratorium that began in April 2010, Gulf of Mexico lease sales conducted by the U.S. government through the BOEM were suspended until December 2011. Leases acquired from the BOEM in the March 2010 lease sale totaled five leases for $8.7 million and in 2009 we acquired three leases for $0.7 million.

Periodically, as part of our business strategy, we sell oil and gas properties that we identify as non-core, which we define as either having limited exploration or development potential or are expected to yield less than our desired return on equity when abandonment costs are considered. In 2011 and 2010, there were no significant property sales. In 2009, we sold one of our fields in Louisiana state waters and we sold 36 non-core oil and natural gas fields in the Gulf of Mexico. 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 2012 is $425.0 million, not including any potential acquisitions. The budget includes $209.0 million to drill, evaluate and complete ten offshore wells (six exploration and four development wells) and $170.0 million to drill, evaluate and complete 65 onshore wells (19 exploration and 46 development wells). The budget also includes $46.0 million for facilities capital, recompletions, seismic and leasehold items. Our 2012 capital budget is subject to change as conditions warrant and we strive to be as flexible as possible.

We intend to continue to pursue acquisitions and joint venture opportunities during 2012 should attractive opportunities arise. We are actively evaluating opportunities and expect to complement our drilling and development projects with acquisitions providing acceptable rates of return. We anticipate funding our 2012 capital budget and acquisitions with internally generated cash flow, cash on hand, borrowings under our revolving loan facility, and accessing the capital markets to the extent necessary.

Dividends. In 2011, we paid $58.8 million in dividends, which includes a special dividend of $46.9 million and regular dividends of $11.9 million. In 2010, we paid $59.6 million in 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. 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, future investment opportunities and other factors as our majority shareholder and the board of directors deems appropriate.

Capital Markets and Impact on Liquidity. During 2011, we accessed the capital markets for our 8.5% Senior Notes and renewed our revolving bank credit facility arrangement as described above. For 2012 to date, the U.S. financial markets have not as of yet been adversely affected by the events in the international markets, including the financial crisis that has threatened the various countries in the Euro zone. Such crisis is having an impact on European banks that have exposure to these countries which could ultimately impact borrowers in the United States. The longer-term outlook could be impacted from these or other international events. At this time, we do not have current plans to obtain additional financing in 2012, but this situation could change depending on a number of factors, such as acquisition opportunities and prices of oil and natural gas.

A fairly recent example of scarce financing availability occurred in 2009 when 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. In addition, prices for oil and natural gas had decreased from 2008. These conditions contributed to fewer financing transactions being completed.

Asset retirement obligations. Each year (or more often if conditions warrant) we review, and to the extent necessary, revise our ARO estimates. Our ARO at December 31, 2011 and 2010 were $393.9 million and $391.3 million, respectively. See *Financial Statements – Note 5 – Asset Retirement Obligations* under Part II, Item 8 of this 10-K for additional information regarding our estimation of our ARO.

Contractual obligations. The following table summarizes our significant contractual obligations by maturity as of December 31, 2011. At December 31, 2011, we did not have any capital leases.

	Payments Due by Period at December 31, 2011				
	Total	Less Than One Year	One to Three Years	Three to Five Years	More Than Five Years
	(Dollars in millions)				
Long-term debt – principal	$ 717.0	$ —	$ —	$117.0	$600.0
Long-term debt – interest (1)	389.2	53.7	107.3	103.0	125.2
Drilling rigs	33.8	32.1	1.7	—	—
Operating leases	12.6	0.3	2.3	2.2	7.8
Asset retirement obligations	393.9	138.2	94.7	47.3	113.7
Derivatives (2)	7.2	7.2	—	—	—
Other liabilities	4.6	—	4.6	—	—
	$1,558.3	$231.5	$210.6	$269.5	$846.7

(1) Interest on long-term debt is comprised of: (a) interest on our 8.5% Senior Notes, which bear interest at a fixed rate of 8.5% and (b) interest on our revolving bank credit facility, which has a variable interest rate, estimated using the annual interest rate effective at December 31, 2011 of 2.3%. Interest was calculated through the stated maturity date of the related debt.

(2) Derivatives contracts that had fair values of assets of $4.1 million were excluded as these did not represent future payments as of December 31, 2011. Future price changes could cause some or all of these derivative contracts to become liabilities resulting in payments in future periods. In addition, the derivative contracts that had fair values of liabilities reported above could have greater payments upon realization depending on the underlying commodity price of oil.

Inflation and Seasonality

Inflation. For 2011, our realized prices for oil increased 37.0%, NGLs increased 27.9% and natural gas decreased 9.5% from 2010. These are discussed in the *Overview* section above. Costs measured on a $/Mcfe basis increased by 3.3% in 2011 compared to 2010. The cost per Mcfe is impacted by factors other than cost changes, such as work activity including workovers, production levels and insurance reimbursements. Historically, costs for goods and services have moved directionally with the price of oil, NGL and natural gas, as these commodities affect the demand for these goods and services. In the last three 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 fluctuated with changes in hurricane activity, the oil spill at the Macondo well and other factors besides production volumes. More recently, many commodity prices, including oil, copper, steel and other types of metals, have fluctuated wildly with various world events. Some of this fluctuation is due to strong economic activity while other changes appear to be driven by political events around the world as well as the weak US dollar and other foreign currencies 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 the storm subsides. 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 *Financial Statements – Note 1 – Significant Accounting Policies* under Part II, Item 8 in this Form 10-K. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue recognition. We recognize oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties with 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. If oil and natural gas prices decrease, we may need to increase this liability. Also, disputes may arise as to volume measurements and allocation of production components between parties. These disputes could cause us to increase our liability for such potential exposure. We do not record receivables for those properties in which the Company has taken less than its ownership share of production which could cause us to delay recognition of amounts due us.

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. The cost of unproved properties related to acquisitions are excluded from the amortization base until it is determined that proved reserves exist or until such time 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 may 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.

DD&A can be affected by several factors other than production. The rate computation includes estimates of reserves which requires significant judgments and is subject to change at each assessment. The determination of when proved reserves exist for our unproved properties requires judgment, which can affect our DD&A rate. Also, estimates of our ARO and estimates of future development costs require significant judgment. Actual results may be significantly different from these estimates, which would affect the timing of when these expenses would be recognized in DD&A. See *Oil and natural gas reserve quantities* and *Asset retirement obligations* below for more information.

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 2011 or 2010, but we did have ceiling test impairments in 2009 as a result of the significant decline in both oil and natural gas prices that began in the second half of 2008. Declines in oil and natural gas prices after December 31, 2011 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, 2011 included in this 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, our oil and natural gas property balance and our DD&A rates.

Fair value measurements. We measure the fair value of our derivative financial instruments by applying the income approach and using inputs that are derived principally from observable market data. Changes in the underlying commodity prices of the derivatives impact the unrealized and realized gain or loss recognized. We do not apply hedge accounting to these derivatives, therefore the change in fair value for all outstanding derivatives, which include derivatives that are hedges against future production, are reflected currently in our statement of income. This can create timing differences between when the production is recognized and when the gain or loss on the derivative is recognized in the income statement.

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 recording 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. The final settlement of these tax positions may occur several years after the tax return is filed and may result in significant adjustments depending on the outcome of these settlements.

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. We estimate forfeitures during the service period and make adjustments depending on actual experience. These adjustments can create timing differences on when expense is recognized.

Accounting Policies and Pronouncements

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 swap and option contracts.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices for oil, NGLs and natural gas, which fluctuate widely. Oil, NGLs 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, NGLs and natural gas sales prices in 2011, our income before income taxes would have decreased by approximately 37% in 2011. If costs and expenses of operating our properties had increased by 10% in 2011, our income before income taxes would have decreased by 9% in 2011.

During 2011 and 2010, we entered into commodity swap and option contracts to manage a portion of our exposure to commodity price risk from sales of oil during the years ended December 31, 2012, 2013 and 2014. As of December 31, 2011, we have derivatives with a notional quantity of 4.2 MMBbl. We do not designate our commodity derivatives as hedging instruments. While these contracts are intended to reduce the effects of volatile oil prices, they may also limit future income from favorable price movements. For additional details about our commodity derivatives, refer to *Financial Statements – Note 6 – Derivative Financial Instruments* under Part II, Item 8 of this Form 10-K.

Interest rate risk. As of December 31, 2011, we had $117.0 million outstanding on our revolving bank credit facility and during 2011 we had amounts outstanding that ranged from zero to $300.0 million. The revolving bank credit facility has a variable interest rate which is primarily impacted by the rates for the London Interbank Offered Rate ("LIBOR") and the margin ranges from 2.0% to 2.75% depending on the amount outstanding. In 2011, if interest rates would have been 100 basis points higher (an additional 1%); our interest expense would have been approximately $0.8 million higher. We did not have any derivatives related to interest rates as of December 31, 2011.

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, 2011 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, 2011 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, 2011, 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, 2011, 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, 2011 and 2010, 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, 2011 of W&T Offshore, Inc. and subsidiaries and our report dated February 27, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 27, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 27, 2012

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

	December 31, 2011	December 31, 2010
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 4,512	$ 28,655
Receivables:		
Oil and natural gas sales	98,550	79,911
Joint interest and other	25,089	25,415
Insurance	715	1,014
Total receivables	124,354	106,340
Deferred income taxes	2,007	5,784
Prepaid expenses and other assets	30,315	23,426
Total current assets	161,188	164,205
Property and equipment – at cost:		
Oil and natural gas properties and equipment (full cost method, of which $154,516 at December 31, 2011 and $65,419 at December 31, 2010 were excluded from amortization)	5,959,016	5,225,582
Furniture, fixtures and other	19,500	15,841
Total property and equipment	5,978,516	5,241,423
Less accumulated depreciation, depletion and amortization	4,320,410	4,021,395
Net property and equipment	1,658,106	1,220,028
Restricted deposits for asset retirement obligations	33,462	30,636
Deferred income taxes	—	2,819
Other assets	16,169	6,406
Total assets	$1,868,925	$1,424,094
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 75,871	$ 80,442
Undistributed oil and natural gas proceeds	33,732	25,240
Asset retirement obligations	138,185	92,575
Accrued liabilities	29,705	25,827
Income taxes payable	10,392	17,552
Total current liabilities	287,885	241,636
Long-term debt, less current maturities	717,000	450,000
Asset retirement obligations, less current portion	255,695	298,741
Deferred income taxes	58,881	—
Other liabilities	4,890	11,974
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value, 2,000,000 shares authorized and 0 issued at December 31, 2011 and at December 31, 2010	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 77,220,706 issued and 74,351,533 outstanding at December 31, 2011; 77,343,520 issued and 74,474,347 outstanding at December 31, 2010;	1	1
Additional paid-in capital	386,920	377,529
Retained earnings	181,820	68,380
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	544,574	421,743
Total liabilities and shareholders' equity	$1,868,925	$1,424,094

See accompanying notes.

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

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per share data)		
Revenues	$971,047	$705,783	$ 610,996
Operating costs and expenses:			
Lease operating expenses	219,206	169,670	203,922
Production taxes	4,275	1,194	1,544
Gathering and transportation	16,920	16,484	13,619
Depreciation, depletion and amortization	299,015	268,415	308,076
Asset retirement obligation accretion	29,771	25,685	34,461
Impairment of oil and natural gas properties	—	—	218,871
General and administrative expenses	74,296	53,290	42,990
Derivative (gain) loss	(1,896)	4,256	7,372
Total costs and expenses	641,587	538,994	830,855
Operating income (loss)	329,460	166,789	(219,859)
Interest expense:			
Incurred	52,393	43,101	46,749
Capitalized	(9,877)	(5,395)	(6,662)
Loss on extinguishment of debt	22,694	—	2,926
Interest income	84	710	842
Income (loss) before income tax expense (benefit)	264,334	129,793	(262,030)
Income tax expense (benefit)	91,517	11,901	(74,111)
Net income (loss)	$172,817	$117,892	$(187,919)
Basic and diluted earnings (loss) per common share	$ 2.29	$ 1.58	$ (2.51)
Weighted average common shares outstanding	74,033	73,685	74,852

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, 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
Cash dividends:								
Common stock regular ($0.16 per share)	—	—	—	(11,913)	—	—	—	(11,913)
Common stock special ($0.63 per share)	—	—	—	(46,842)	—	—	—	(46,842)
Share-based compensation	—	—	9,710	—	—	—	—	9,710
Restricted stock issued, net of forfeitures	(13)	—	—	—	—	—	—	—
Shares surrendered for payroll taxes	(109)	—	(2,073)	—	—	—	—	(2,073)
Other	—	—	1,754	(622)	—	—	—	1,132
Net income	—	—	—	172,817	—	—	—	172,817
Balances at December 31, 2011	74,352	$ 1	$386,920	$ 181,820	2,869	$(24,167)	$ —	$ 544,574

See accompanying notes.

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

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Operating activities:			
Net income (loss)	$ 172,817	$ 117,892	$(187,919)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	328,786	294,100	345,637
Impairment of oil and natural gas properties	—	—	218,871
Amortization of debt issuance costs and discount on indebtedness	2,010	1,338	1,838
Loss on extinguishment of debt	22,694	—	2,817
Share-based compensation	9,710	5,533	6,380
Derivative (gain) loss	(1,896)	4,256	7,372
Cash payments on derivative settlements	(9,873)	874	(6,679)
Deferred income taxes	61,835	(8,266)	(346)
Other	—	—	998
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(18,639)	(24,933)	(18,509)
Joint interest and other receivables	375	25,897	31,866
Insurance receivables	20,771	54,873	23,235
Income taxes	(7,124)	104,067	(52,100)
Prepaid expenses and other assets	(7,809)	4,536	(749)
Asset retirement obligations	(59,958)	(87,166)	(99,069)
Accounts payable and accrued liabilities	7,881	(31,885)	(117,230)
Other liabilities	(102)	3,656	(147)
Net cash provided by operating activities	521,478	464,772	156,266
Investing activities:			
Acquisition of property interest in oil and natural gas properties	(437,247)	(236,944)	(2,421)
Investment in oil and natural gas properties and equipment	(281,779)	(178,709)	(273,713)
Proceeds from sales of oil and natural gas properties and equipment	15	1,420	32,226
Proceeds from insurance	—	—	6,916
Purchases of furniture, fixtures and other, net	(3,660)	(760)	(705)
Net cash used in investing activities	(722,671)	(414,993)	(237,697)
Financing activities:			
Issuance of 8.5% Senior Notes	600,000	—	—
Repurchase of 8.25% Senior Notes	(450,000)	—	—
Borrowings of long-term debt – revolving bank credit facility	623,000	627,500	205,441
Repayments of long-term debt – revolving bank credit facility	(506,000)	(627,500)	(410,941)
Repurchase premium and debt issuance costs	(32,288)	—	—
Dividends to shareholders	(58,756)	(59,609)	(9,158)
Repurchases of common stock	—	—	(24,167)
Other	1,094	298	891
Net cash provided by (used in) financing activities	177,050	(59,311)	(237,934)
Decrease in cash and cash equivalents	(24,143)	(9,532)	(319,365)
Cash and cash equivalents, beginning of period	28,655	38,187	357,552
Cash and cash equivalents, end of period	$ 4,512	$ 28,655	$ 38,187

See accompanying notes.

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

1. Significant Accounting Policies

Operations

W&T Offshore, Inc. and subsidiaries, referred to herein as "W&T" or the "Company," is an independent oil and natural gas producer focused primarily in the Gulf of Mexico and, more recently, onshore Texas. The Company is active in the acquisition, exploration and development of oil and natural gas properties.

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. In Note 13, certain state income tax items were previously reported separately and are now combined with other items due to being immaterial. In Note 22, reserve information related to oil and natural gas liquids ("NGLs") is reported separately due to the increase in NGLs as a percent of total reserves and these had been combined in prior periods. The historical information was modified to report oil and NGLs separately for comparability to the current year's information.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") 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.

Fiscal Year

Our fiscal year ends on December 31.

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 with 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, 2011 and 2010, $6.5 million and $6.5 million, respectively, were 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. We also have receivables from joint interest owners on properties we operate and we may have the ability to withhold future revenue disbursements to recover amounts due us. We attempt to minimize our credit risk exposure to purchasers of our oil and natural gas, joint interest owners, derivative counterparties and other third-party entities 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,		
	2011	2010	2009
Customer			
Shell Trading (US) Co.	36%	40%	34%
ConocoPhillips	16%	17%	**
J.P. Morgan Ventures Energy Corp.	10%	**	15%
Chevron Corp.	**	**	13%

** 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 on terms, conditions and pricing substantially similar to those currently existing.

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 $9.9 million, $5.4 million and $6.7 million of interest expense during the years 2011, 2010, and 2009, 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, related to developing proved reserves. These additional costs related to developing proved reserves are not recorded as liabilities on the balance sheet.

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, 2011, 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 March 31, 2009, commodity prices were based on the end-of-the-period prices using guidance effective for that reporting period. We recorded a ceiling test impairment in 2009 of $218.9 million primarily as a result of a decline in natural gas prices as of March 31, 2009. Declines in oil and natural gas prices after December 31, 2011 may require us to record additional ceiling test impairments in the future. We did not have a ceiling test impairment during the years 2011 and 2010, respectively.

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 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, each of the quarters of 2010 and each of the quarters of 2011 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% 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 22 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. 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 credit facility. Our derivative instruments currently consist of commodity swap and option contracts for oil. 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 and documentation criteria are met at the time the derivative contract is entered into. We have elected not to designate our commodity derivatives as hedging instruments, therefore all changes in fair value are recognized 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. We believe that the book value of our restricted deposits approximates fair value as deposits are in cash or short-term investments.

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 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. Early adoption was permitted and we elected to apply the amendments for the year 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.

2. Acquisitions

2011 Acquisitions

On May 11, 2011, we completed the acquisition of approximately 24,500 gross acres (21,900 net acres) of oil and gas leasehold interests in the West Texas Permian Basin (the "Yellow Rose Properties") from Opal Resources LLC and Opal Resources Operating Company LLC (collectively, "Opal"). The cash component of the stated purchase price was $366.3 million, subject to certain adjustments, including adjustments from an effective date of January 1, 2011 until the closing date of May 11, 2011. Taking into account such adjustments, the adjusted cash component of the purchase price was $394.4 million. The increase of $28.1 million primarily reflects drilling costs in excess of cash flow from the effective date of January 1, 2011 to the closing date. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

The following table presents the purchase price allocation for the acquisition of the Yellow Rose Properties (in thousands):

Oil and natural gas properties and equipment (1)	$396,902
Asset retirement obligations – non-current	(382)
Long-term liability	(2,143)
Total cash paid	$394,377

(1) At the acquisition date, $84.7 million was recorded as unproved properties. During 2011, this amount was increased by $4.5 million due to capitalized interest and decreased by $3.5 million due to reclassifications to proved properties resulting in $85.7 million in unproved properties as of December 31, 2011 for the Yellow Rose Properties. Amounts recorded as unproved properties are excluded from the full cost pool and amortization base.

On August 10, 2011, we completed the acquisition of Shell Offshore Inc.'s ("Shell") 64.3% interest in the Fairway Field along with a like interest in the associated Yellowhammer gas treatment plant (collectively, the "Fairway Properties"). The cash component of the stated purchase price was $55.0 million, subject to certain adjustments, including adjustments from an effective date of September 1, 2010 until the closing date of August 10, 2011. Taking into account such adjustments, as of December 31, 2011, the cash component of the purchase price was $42.9 million. The decrease of $12.1 million primarily reflects net production cash flow, partially offset by plugging and abandonment costs incurred, from the effective date of September 1, 2010 to the closing date. The purchase price is subject to further post-effective date adjustments and final settlement is expected to occur in the first half of 2012. We assumed the asset retirement obligations associated with the properties, which we have estimated to be $7.8 million. The acquisition was funded from borrowings under our revolving bank credit facility.

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

Oil and natural gas properties and equipment	$50,682
Asset retirement obligations – non-current	(7,812)
Total cash paid	$42,870

Expenses associated with acquisition activities and transition activities related to the Yellow Rose and Fairway acquisitions for the year 2011 were $1.6 million and are included in general and administrative expenses.

Revenue, Net Income and Pro Forma Financial Information – Unaudited

For the year 2011, the Yellow Rose Properties and the Fairway Properties accounted for $64.0 million of revenue, $25.5 million of direct operating expenses, $20.5 million of depreciation, depletion, amortization and accretion ("DD&A") and $6.3 million of income taxes, resulting in $11.7 million of net income. Such amounts are for the period from each respective close date to December 31, 2011. The net income attributable to these properties does not reflect certain expenses, such as general and administrative expenses and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Yellow Rose Properties and the Fairway Properties are not recorded in a separate entity for tax purposes; therefore, income tax was estimated using the federal statutory tax rate.

Pro forma financial information has been prepared since the Yellow Rose Properties constitute a significant acquisition. The Fairway Properties acquisition, which was not significant, was combined with the Yellow Rose Properties to disclose the effect of both acquisitions upon our results of operations. The unaudited pro forma financial information was computed as if these two acquisitions had been completed on January 1, 2010. The historical financial information is derived from the audited historical consolidated financial statements of W&T and the unaudited historical statements of the sellers.

The pro forma adjustments were based on estimates by management and information believed to be directly related to the purchase of the Yellow Rose Properties and the Fairway Properties. The pro forma financial information is not necessarily indicative of the results of operations had the respective purchases occurred on January 1, 2010. If the transactions had been in effect for the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than the sellers, realized oil, NGLs and natural gas sales prices may have been different and costs of operating the properties may have been different. The following table presents a summary of our pro forma financial information (in thousands except earnings per share):

	(unaudited) Year Ended December 31,	
	2011	**2010**
Revenue	$1,023,430	$784,964
Net income (loss)	180,779	113,783
Basic and diluted earnings (loss) per common share	2.39	1.52

The purchase price of both acquisitions may be subject to further adjustments. For the pro forma financial information, we assumed the transactions were financed with borrowings from the revolving bank credit facility because the cash and cash equivalents balances for the assumed acquisition date was less than the cash and cash equivalents on hand used on the actual closing dates of the two acquisitions. Also, we assumed that the revolving bank credit facility capacity would have been increased due to the increase in reserves.

The following adjustments were made in the preparation of the financial information:

(a) Revenues and direct operating expenses for the Yellow Rose Properties and the Fairway Properties were derived from the historical records of the sellers up to the respective closing dates.

(b) DD&A was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Yellow Rose Properties and Fairway Properties' costs, reserves and production into our currently existing full cost pool in order to compute such amounts. The purchase price allocation included $81.2 million that was allocated to the pool of unevaluated properties for oil and gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties.

(c) Asset retirement obligations and related accretion were estimated by W&T management.

(d) Incremental transaction expenses related to the acquisitions completed during 2011 were $1.6 million and were assumed to be funded from cash on hand.

(e) Interest expense was computed using interest rates that were in effect during the applicable time period and we assumed that six-month London Interbank Offered Rate ("LIBOR") borrowings were made as allowed under the revolving bank credit facility. The assumed interest rates ranged from 3.1% to 3.5%. A reduction in the revolving bank credit facility commitment fee related to the assumed borrowings was netted against the computed incremental interest expense.

(f) Incremental capitalized interest was computed for the addition to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings.

(g) Income tax expense was computed using the 35% federal statutory rate.

2010 Acquisitions

During 2010, we closed on two acquisition transactions. The first acquisition closed on April 30, 2010. Through our wholly-owned subsidiary, W&T Energy VI, LLC ("Energy VI"), we acquired all of Total E&P USA's ("Total") interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico and assumed the ARO for plugging and abandonment of the acquired interests. The adjusted purchase price was $121.3 million inclusive of ARO. There were no adjustments to the purchase price in 2011. The properties acquired from Total (the "Matterhorn/Virgo Properties") are producing interests 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 second acquisition closed 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 and assumed the ARO for plugging and abandonment of the acquired interests. The adjusted purchase price recorded in 2010 was $139.9 million inclusive of ARO. In 2011, the adjusted purchase price inclusive of ARO was subsequently reduced to $134.2 million due to settlement adjustments of $5.7 million determined and received in 2011. The properties acquired from Shell (the "Tahoe/Droshky Properties") are producing interests 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 following table presents the purchase price allocation for the acquisition of the Matterhorn/Virgo Properties (in thousands):

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

The following table presents the purchase price allocation for the acquisition of the Tahoe/Droshky Properties (in thousands):

Oil and natural gas properties and equipment	$134,189
Asset retirement obligations – non-current	(17,956)
Total cash paid	$116,233

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. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention requirement of $10.0 million per occurrence to be satisfied by us before we could be indemnified for losses. In the fourth quarter of 2008, we satisfied our $10.0 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 $150.0 million for property damage due to named windstorms (excluding certain damage incurred at our facilities of marginal significance) and $250.0 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 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 expense (in thousands), with bracketed amounts representing credits to expense:

	Year Ended December 31,		
	2011	2010	2009
Incurred and reversals of accruals	$ 132	$ (1,380)	$ 37,062
Plus amounts returned to insurers	1,241	—	—
Less amounts approved for payment by insurers	(1,334)	(10,350)	(18,683)
Included in lease operating expenses	$ 39	$(11,730)	$ 18,379

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, which arises when our insurance underwriters' adjuster reviews and approves such costs for payment by the underwriters. Claims that have been processed in this manner have customarily been paid on a timely basis. Incurred expenses included revisions of previous estimates. Amounts in 2011 include return of reimbursements that were previously received by us related to prepayments based on preliminary estimates. In 2010, incurred expenses were a credit due to revisions of previous estimates. See Note 5 for additional information about the impact of hurricane related items on our asset retirement obligations.

Below is a reconciliation of our insurance receivables (in thousands):

Balance, December 31, 2010	$ 1,014
Costs approved under our insurance policies, net	20,566
Payments received, net	(20,865)
Balance, December 31, 2011	$ 715

At December 31, 2011 and December 31, 2010, substantially all of the amounts in insurance receivables relate to the plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike.

From the third quarter of 2008 through December 31, 2011, we have received $139.3 million from our insurance carrier related to Hurricane Ike. To the extent that additional remediation cost or plug and abandonment costs are incurred that are not covered by insurance, we expect that our available cash and cash equivalents, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricane Ike.

4. Restricted Deposits

Restricted deposits as of December 31, 2011 and 2010 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 an arrangement with Total where we are required to make annual increases in the security amount.

The arrangement with Total requires security either through bonds or payments to an escrow account in accordance with the Purchase and Sale Agreement. Pursuant to the Purchase and Sale Agreement, monthly payments are made to an escrow account for our overriding royalty interests related to the Droshky field and these funds are returned once verification is made as to fulfilling the security requirements. In addition, funds are returned as asset retirement obligations are fulfilled. We were in compliance with the requirements as of December 31, 2011 and have provided funds to fulfill our security requirement for December 31, 2012. See Note 17 for future security requirements.

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 (in thousands).

	2011	2010
Asset retirement obligation, beginning of period	$391,316	$348,800
Liabilities settled	(59,958)	(87,166)
Accretion of discount	29,771	25,685
Disposition of properties	—	(2,070)
Liabilities assumed through acquisition	8,194	24,477
Liabilities incurred	565	503
Revisions of estimated liabilities due to Hurricane Ike	4,744	41,952
Revisions of estimated liabilities due to NTL 2010-G05 (1)	—	18,725
Revisions of estimated liabilities – all other	19,248	20,410
Asset retirement obligation, end of period	393,880	391,316
Less current portion	138,185	92,575
Long-term	$255,695	$298,741

(1) NTL No. 2010-G05, *"Decommissioning Guidance for Wells and Platforms"* issued by the Bureau of Ocean Energy Management ("BOEM") (a) on September 15, 2010 and effective as of October 15, 2010, requires 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 causes our estimated liabilities for ARO to be incurred in earlier periods, resulting in a higher present value of such liabilities.

(a) In June 2010, the Minerals Management Service changed its name to the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"). In October 2011, the BOEMRE was split into three separate entities: the Office of Natural Resources Revenue ("ONRR"), which assumed the functions of the Minerals Revenue Management Program; the BOEM, which is responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way; and the Bureau of Safety and Environmental Enforcement ("BSEE"), which is responsible for enforcement of safety and environmental regulations.

Each year (or more often if conditions warrant) we review and, to the extent necessary, revise our ARO estimates. During 2011, we reduced our ARO by $60.0 million for the plug and abandonment work performed during the year (including $23.0 million to plug and abandon wells and facilities damaged by Hurricane Ike). Offsetting this decrease were the acquisitions of properties, including the Yellow Rose Properties and the Fairway Properties, which increased our obligations by $8.2 million. In addition, revisions were made related to Hurricane Ike, which increased the liability by $4.7 million. Other estimates were increased by $19.2 million primarily attributable to changes in estimates for non-operated properties and accelerating the expected timing of performing the work.

During 2010, we reduced our ARO by $87.2 million for the plug and abandonment work performed during the year (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.

6. Derivative Financial Instruments

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 bank credit facility. We do not enter into derivative instruments for speculative trading purposes. Our derivative instruments currently consist of commodity swap and option contracts. We are exposed to credit loss in the event of nonperformance by the counterparties (Natixis; ING Capital Markets, LLC-EDP; the Toronto Dominion Bank; and BNP Paribas Corporate and Investment Banking); however, we do not currently anticipate any of our counterparties being unable to fulfill their contractual obligations.

In accordance with GAAP, each derivative is 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 we enter into a derivative contract. We do not attempt to qualify our derivatives for hedge accounting under GAAP; therefore, all changes in fair value are recognized in earnings. For additional information about fair value measurements, refer to Note 8.

Commodity Derivatives

During 2011 and 2010, we entered into commodity option contracts and swap contracts to manage a portion of our exposure to commodity price risk from sales of oil through December 31, 2014. 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, 2011, our open commodity derivatives were as follows:

Zero Cost Collars – Oil

Termination Period		Notional Quantity (Bbls)	Weighted Average Contract Price		Fair Value Liability (in thousands)
			Floor	Ceiling	
2012:	1st quarter	364,000	$75.00	$97.88	$1,735
	2nd quarter	364,000	75.00	97.88	2,707
	3rd quarter	124,000	75.00	97.88	972
	4th quarter	251,000	75.00	98.99	1,785
		1,103,000	$75.00	$98.13	$7,199

Swaps – Oil

Termination Period		Notional Quantity (Bbls)	Weighted Average Contract Price	Fair Value Net Asset (in thousands)
2012:	1st quarter	236,600	$107.28	$ 124
	2nd quarter	200,200	107.28	294
	3rd quarter	414,000	107.28	1,023
	4th quarter	257,600	107.28	901
2013:	1st quarter	351,000	101.97	(171)
	2nd quarter	336,700	101.97	217
	3rd quarter	312,800	101.98	543
	4th quarter	294,400	101.98	820
2014:	1st quarter	180,000	97.38	(125)
	2nd quarter	172,900	97.38	39
	3rd quarter	165,600	97.38	161
	4th quarter	156,400	97.37	261
		3,078,200	$102.87	$4,087

At December 31, 2011, $7.2 million was included in *Accrued liabilities*, $2.3 million was included in *Prepaid and other assets* and $1.8 million was included in *Other assets* related to the fair value of our commodity derivative contracts. 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 the fair value of our commodity derivative contracts. The zero cost collars are priced off the West Texas Intermediate crude oil price quoted on the New York Mercantile Exchange and the swaps are priced off the Brent crude oil price quoted on the IntercontinentalExchange, known as ICE.

Changes in the fair value of our commodity derivative contracts are recognized currently in earnings. Our derivative gain for the year 2011 includes a realized loss of $9.9 million and an unrealized gain of $11.8 million, related to our commodity derivatives. Our derivative loss for the year 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 2009 includes realized and unrealized losses of $0.2 million and $5.4 million, respectively, related to our commodity derivatives.

Interest Rate Swap

Changes in the fair value of our interest derivative contract are also recognized currently in earnings. Our interest rate swap contract with a fixed interest rate of 5.21% expired in August 2010. During 2010, we recognized an unrealized gain of $4.4 million and a realized loss of $4.7 million for this contract. During 2009, we recognized an unrealized gain of $4.7 million and a realized loss of $6.5 million for this contract.

7. Long-Term Debt

As of December 31, 2011 and 2010 our long-term debt was as follows (in thousands):

	December 31, 2011	December 31, 2010
8.5% Senior Notes, due June 2019	$600,000	$ —
8.25% Senior Notes, due June 2014	—	450,000
Revolving bank credit facility due May 2015	117,000	—
Total long-term debt	717,000	450,000
Current maturities of long-term debt	—	—
Long-term debt, less current maturities	$717,000	$450,000

Aggregate annual maturities of long-term debt as of December 31, 2011 are as follows (in millions): 2012–$0.0; 2013 – $0.0; 2014 – $0.0; 2015 – $117.0; thereafter – $600.0.

See Note 8 for the estimated fair value of our Senior Notes and additional details about fair value measurements.

Senior Notes

On June 10, 2011, we issued $600.0 million of our senior notes at par with an interest rate of 8.5% and maturity date of June 15, 2019 (the "8.5% Senior Notes"). Interest is payable semi-annually in arrears on June 15 and December 15 of each year. The 8.5% Senior Notes are unsecured and are fully and unconditionally guaranteed by certain of our subsidiaries. At December 31, 2011, the outstanding balance of our 8.5% Senior Notes was $600.0 million and was classified at their carrying value as long-term debt. The estimated annual effective interest rate on the 8.5% Senior Notes is 8.7% which includes amortization of debt issuance costs. At December 31, 2011, the estimated fair value of the 8.5% Senior Notes was approximately $612.0 million. In January 2012, holders of the 8.5% Senior Notes exchanged their senior notes for registered notes with the same terms.

In June and July of 2011, we used a portion of the net proceeds from the issuance of the 8.5% Senior Notes to repurchase all of our 8.25% Senior Notes due 2014 (the "8.25% Senior Notes"), which had a principal amount of $450.0 million. Costs of $22.0 million related to repurchasing the 8.25% Senior Notes, which included repurchase premiums and the unamortized debt issuance costs, are included in the statement of income within the line item classification, *Loss on extinguishment of debt*.

At December 31, 2010, the outstanding balance of our 8.25% Senior Notes was $450.0 million and was classified at their carrying value as long-term debt. At December 31, 2010, the estimated fair value of the 8.25% Senior Notes was approximately $441.0 million.

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.

We and our restricted subsidiaries are subject to certain covenants under the indenture governing the 8.5% Senior Notes, which limit our and our 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. We were in compliance with all applicable covenants of the indenture governing the 8.5% Senior Notes as of December 31, 2011.

Credit Agreement

On May 5, 2011, we entered into the Fourth Amended and Restated Credit Agreement (the “Credit Agreement”), which provides a revolving bank credit facility with an initial borrowing base of $525.0 million. In October 2011, the borrowing base was re-determined by our lenders and increased to $575.0 million. This is a secured facility that is collateralized by our oil and natural gas properties. The Credit Agreement terminates on May 5, 2015 and replaces the prior Third Amended and Restated Credit Agreement (the “Prior Credit Agreement”). Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility.

The Credit Agreement contains covenants that restrict, among other things, the payment of cash dividends of up to $60.0 million per year, common stock repurchases and Senior Note repurchases of up to $100.0 million, borrowings other than from the revolving bank credit facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. Letters of credit may be issued up to $90.0 million, provided availability under the revolving bank credit 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, 2011.

Borrowings under the revolving bank credit facility bear interest at the applicable LIBOR plus a margin that varies from 2.00% to 2.75% depending on the level of total borrowings under the Credit Agreement, or an alternative base rate equal to the applicable margin ranging from 1.00% to 1.75% plus the highest of the (a) Prime Rate, (b) Federal Funds Rate plus 0.50%, and (c) LIBOR plus 1.0%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%. The estimated annual effective interest rate was 3.7% for 2011 for borrowings under the Credit Agreement and the Prior Credit Agreement. The estimated annual effective interest rate includes amortization of debt issuance costs and excludes commitment fees and other costs.

Unamortized debt issuance costs of $0.7 million related to the Prior Credit Agreement were written off and are included in the statement of income within the line item classification, *Loss on extinguishment of debt*.

At December 31, 2011, we had $117.0 million in borrowings and $0.4 million in letters of credit outstanding under the revolving bank credit facility. The carrying amount of our revolving bank credit facility debt approximates fair value because the interest rates are variable and reflective of market rates. At December 31, 2010, we had no borrowings and $0.4 million in letters of credit outstanding under the revolving bank credit facility provided by the Prior Credit Agreement.

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 Senior Notes (in thousands).

		December 31,			
		2011		2010	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$ 4,087	$ 7,199	$ —	$ 14,882
Senior Notes	Level 2	—	612,000	—	441,000
Revolving bank credit facility	Level 2	—	117,000	—	—

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 which was $600.0 million and $450.0 million at December 31, 2011 and 2010, respectively. The revolving bank credit facility debt is reported in the statement of financial position at its carrying value which was $117.0 million and nil at December 31, 2011 and 2010, respectively.

We measure the fair value of our derivative financial instruments by applying the income approach and 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 implied volatility, the discount curve with spreads 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. The carrying amount of debt under our revolving bank credit facility approximates fair value because the interest rates are variable and reflective of market rates. For additional information about our derivative financial instruments refer to Note 6 and for additional information on our Senior Notes and revolving bank credit facility refer to Note 7.

9. Equity Structure and Transactions

As of December 31, 2011 and 2010, 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 $25.0 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 2011, 2010 and 2009, we paid regular cash dividends of $0.16, $0.14 and $0.12 per common share per year, respectively. In December, 2011, we paid a special dividend of $0.63 per share or $46.9 million. In December, 2010, we paid a special dividend of $0.66 per share or $49.2 million. No special dividend was paid in 2009. On February 23, 2012, our board of directors declared a cash dividend of $0.08 per common share, payable on March 30, 2012 to shareholders of record on March 14, 2012.

10. Incentive Compensation Plan

In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan (the "Plan") was approved by our 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 ("IRC"). 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 of 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 2011, 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. RSUs are a long-term compensation component of the Plan, which are granted to only certain employees, and are subject to adjustments at the end of the applicable performance period based on the Company achieving certain predetermined performance criteria. The sole business performance criteria established for the 2011 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, 2013. The cash-based awards, which are a short-term component of the Plan, were determined based on multiple performance measures, such as earnings per share, reserve and production growth, cost containment and individual performance measures. With respect to the 2011 cash-based awards, most of the performance criteria targets were achieved and individual performance was estimated at the mid-point of the eligible range. Employees will be paid their cash-based awards within 75 days following year end 2011.

For 2010, performance awards under the Plan were granted in the form of RSUs and cash awards. 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. With respect to the 2010 cash-based awards, most of the performance criteria targets were achieved.

In 2009, the Previous Plan was effective. Awards consisted of a general award and an extraordinary performance award. For 2009, the Company's performance did not achieve any of the targets; therefore no awards were granted that were related to Company performance.

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. 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 restricted stock 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 and Cash-Based Incentive Compensation

In accordance with the *Compensation – Stock Compensation* topic of the Codification, we recognize compensation cost on a straight line basis 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 2011 and August 2010, the Company granted RSUs to certain of its employees and in January 2011, the Company granted restricted stock to one of its employees. Prior to 2010, the Company granted only restricted stock to its employees. In 2011 and in prior years, restricted stock was granted to the Company's non-employee directors under the Director Compensation Plan. In addition to share-based compensation, the Company granted its employees cash-based incentive awards in 2011 and in 2010.

At December 31, 2011, there were 2,269,745 shares of common stock available for award under the Plan and 568,783 shares of common stock available for award under the Directors Compensation Plan.

Restricted Stock

Under the Company's share-based payment plans, restricted shares were issued to only one employee in 2011 and no restricted shares were issued to employees in 2010. Restricted shares were issued to employees in 2009. In 2011, 2010 and 2009, 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 is as follows:

	2011		2010		2009	
	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	470,392	$ 7.42	1,050,506	$ 8.48	233,703	$30.33
Granted	20,433	25.45	35,000	10.00	1,570,436	6.91
Vested	(404,422)	7.31	(485,934)	9.69	(653,676)	12.18
Forfeited	(34,533)	6.83	(129,180)	8.15	(99,957)	10.77
Nonvested, end of period	51,870	15.81	470,392	7.42	1,050,506	8.48

At December 31, 2011, the composition of our restricted stock awards outstanding, by year granted, was as follows:

	Shares
Employees – granted in:	
2011	2,662(1)
Non-employee directors – granted in:	
2011	15,108(2)
2010	23,330(3)
2009	10,770(4)
Total	51,870

Subject to employment conditions and less any forfeitures, vesting of restricted stock will occur as follows:

(1) December 2012.
(2) Equal installments in May 2012, 2013 and 2014.
(3) Equal installments in May 2012 and 2013.
(4) May 2012.

The grant date fair value of restricted stock granted during the years 2011, 2010 and 2009 was $0.5 million, $0.4 million and $10.9 million, respectively. The fair value of the restricted stock that vested during the years ended 2011, 2010 and 2009 was $7.9 million, $8.1 million and $7.4 million, respectively, based on the closing prices on the dates of vesting.

Restricted Stock Units

During 2011 and 2010, the Company awarded to certain employees RSUs that were 100% contingent upon meeting specified performance requirements. The specific performance requirements were achieved in 2011 and 2010. Vesting occurs upon completion of the specified vesting period applicable to each award. Effective January 2012, the RSUs awarded in 2011 and 2010 will earn dividend equivalents at the same rate as dividends paid on our common stock. During 2011, RSUs awarded in 2010 earned dividend equivalents at the same rate as dividends paid on our common stock. RSUs awarded in both years 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 is as follows:

	2011		2010	
	RSUs	Weighted Average Grant Date Price Per Unit	RSUs	Weighted Average Grant Date Price Per Unit
Nonvested, beginning of period	1,266,617	$ 9.36	—	$—
Granted	534,375	26.93	1,280,501	9.36
Vested	—	—	—	—
Forfeited	(68,289)	12.03	(13,884)	9.36
Nonvested, end of period (1)	1,732,703	14.67	1,266,617	9.36

(1) Subject to employment conditions and less any forfeitures, 1,208,714 and 523,989 RSUs will vest in December 2012 and 2013, respectively.

During the years 2011 and 2010, the grant date fair value of RSUs granted was $14.4 million and $12.0 million, respectively.

Share-Based Compensation

A summary of compensation expense under share-based payment arrangements and the related tax benefit is as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Share-based compensation expense from:			
Restricted stock	$2,377	$3,469	$7,730
Restricted stock units	7,333	2,064	—
Total	$9,710	$5,533	$7,730
Share-based compensation tax benefit:			
Tax benefit computed at the statutory rate	$3,399	$1,937	$2,706

As of December 31, 2011, unrecognized share-based compensation expense related to our issued restricted shares and RSUs was $0.6 million and $15.7 million, respectively. Unrecognized compensation expense will be recognized through April 2014 for restricted shares and November 2013 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 is as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Share-based compensation expense included in:			
Lease operating expense	$ 466	$ 748	$ 2,242
General and administrative	9,244	4,785	5,488
Total charged to operating income (loss)	9,710	5,533	7,730
Cash-based incentive compensation included in:			
Lease operating expense	3,700	2,067	1,472
General and administrative	12,213	8,539	1,525
Total charged to operating income (loss)	15,913	10,606	2,997
Total incentive compensation charged to operating income (loss)	$25,623	$16,139	$10,727

12. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the IRC (the "401(k) Plan"), which covers those employees who meet the 401(k) Plan's eligibility requirements. During 2011, 2010 and 2009, 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 $1.8 million, $1.4 million and $1.5 million for the years 2011, 2010 and 2009, respectively.

13. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2011	2010	2009
Current	$29,682	$20,167	$(74,111)
Deferred	61,835	(8,266)	—
	$91,517	$11,901	$(74,111)

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,					
	2011		2010		2009	
Income tax expense (benefit) at the federal statutory rate	$92,517	35.0%	$ 45,427	35.0%	$(91,710)	35.0%
Valuation allowance	—	—	(31,985)	(24.6)	14,594	(5.6)
Domestic production activities deduction	(1,823)	(0.7)	(2,623)	(2.0)	3,167	(1.2)
Share-based compensation	—	—	—	—	208	—
State income taxes	603	0.2	32	—	(73)	—
Other	220	0.1	1,050	0.8	(297)	0.1
	$91,517	34.6%	$ 11,901	9.2%	$(74,111)	28.3%

Our effective tax rate for the year 2011 consists primarily of the federal statutory rate with an adjustment for the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the IRC. Our effective tax rate for the year 2010 primarily reflects a reduction in our valuation allowance against our deferred tax assets and the Section 199 deduction described above. Taxable income in 2010 allowed us to reverse all of the previously recorded valuation allowance. Our effective tax rate for the year 2009 primarily reflects recapture of the Section 199 deduction 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. In 2009, the Company experienced a net operating loss for tax purposes and as a result, the Section 199 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.

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,	
	2011	2010
Deferred tax liabilities:		
Property and equipment	$ 63,328	$ 2,370
Other	4,707	3,274
Total deferred tax liabilities	68,035	5,644
Deferred tax assets:		
Minimum tax credit	—	3,558
State net operating losses	4,626	4,176
Derivatives	1,096	4,622
Valuation allowance	(4,626)	(4,176)
Accrued cash-based bonus	5,390	4,022
Stock-based compensation	3,971	1,581
Other	704	464
Total deferred tax assets	11,161	14,247
Net deferred tax (liabilities) assets	$(56,874)	$ 8,603

During the year 2011, we made payments primarily for federal and state income taxes of approximately $35.7 million. We received refunds related to prior years of $0.4 million.

During the year 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 and made payments of $12.0 million for federal and state income taxes. 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.

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, 2011 (in thousands):

	Amount	Expiration Year
State net operating loss	$88,963	2020-2025

Valuation Allowance

As of December 31, 2011 and December 31, 2010, we had a valuation allowance related to state net operating losses. 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.

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, 2011, we had zero accrued interest related to uncertain tax positions. During 2011, we recognized $0.3 million of income tax benefit for the reversal of accrued interest and penalties.

Balances and changes in the uncertain tax positions are as follows (in thousands):

	December 31,	
	2011	2010
Balance at beginning of period	$ 3,558	$ —
Increase related to current-year tax positions	—	3,558
(Decreases) related to prior-year tax positions	(3,558)	—
Balance at end of period	$ —	$3,558

Years open to examination

The tax years from 2008 through 2011 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 (in thousands, except per share amounts):

	Year Ended December 31,		
	2011	2010	2009
Net income (loss)	$172,817	$117,892	$(187,919)
Less portion allocated to nonvested shares	3,211	1,178	—
Net income (loss) allocated to common shares	$169,606	$116,714	$(187,919)
Weighted average common shares outstanding	74,033	73,685	74,852
Basic and diluted earnings (loss) per common share	$ 2.29	$ 1.58	$ (2.51)
Shares excluded due to being anti-dilutive	1,873	1,540	1,347

15. Comprehensive Income (Loss)

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

	Year Ended December 31,		
	2011	2010	2009
Net income (loss)	$172,817	$117,892	$(187,919)
Amounts reclassified to income, net of income tax of $0 in 2011, $0 in 2010 and $346 in 2009 (1)	—	—	643
Comprehensive income (loss)	$172,817	$117,892	$(187,276)

(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.

16. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2011	2010	2009
Cash paid for interest, net of interest capitalized of $9,877 in 2011, $5,395 in 2010 and $6,662 in 2009	$39,772	$36,362	$37,286
Cash paid for income taxes	35,655	12,000	100
Cash paid for share-based compensation (1)	1,062	452	162
Cash tax benefit related to share-based compensation (2)	3,125	6,871	—

(1) The cash paid for share-based compensation is for dividends on unvested restricted stock and for dividend equivalents paid on RSUs. 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, tax deductions for dividends paid on unvested restricted stock and tax deductions related to dividend equivalents paid on RSUs. 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 2011, 2010 and 2009, we received refunds of federal income taxes paid in prior years totaling $0.4 million, $99.8 million and $22.3 million, respectively.

17. Commitments

We have operating lease agreements for office space and office equipment. The lease for the majority of our office space terminates in December 2022. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2011 are as follows (in millions): 2012 – $0.3; 2013 – $1.2; 2014 – $1.1; thereafter – $10.0.

Total rent expense was approximately $1.9 million, $2.0 million and $2.2 million during the years 2011, 2010 and 2009, respectively.

Pursuant to the Purchase and Sale Agreement with Total, we are required to fulfill security requirements through bonds or making payments to an escrow account. Additional security requirements are nil in 2012, $9.0 million in 2013, $9.0 million in 2014, $9.0 million in 2015 and $30.0 million in the 2016 to 2023 time period.

We have one drilling rig commitment with a term that exceeded one year as of December 31, 2011 and our drilling rig commitments meet the criteria of an operating lease. Future payments of all drilling rig commitments as of December 31, 2011 were $32.1 million in 2012, $1.7 million in 2013 and none beyond 2013.

18. Related Parties

During 2011, 2010, and 2009, there were certain transactions between us and companies that were controlled by our majority shareholder. The transactions were primarily for use of jet services and transactions related to insurance. Our majority shareholder owns a certain aircraft that the Company used and reimbursed him for such use and for his use. Jet services were charged to us at rates that were either equal to or below rates charges by non-related, third-party companies. Jet services transactions were approximately $1.1 million, $0.9 million and $0.1 million for the years 2011, 2010 and 2009, respectively. In addition, our majority shareholder has ownership interests in certain wells operated by us (such ownership interests pre-date our initial public offering). Revenues are disbursed and expenses are collected in accordance with ownership interest. Proportionate insurance premiums were paid to us and proportionate collections of insurance reimbursements attributable to damage on certain wells were disbursed.

19. Contingencies

The United States Attorney's Office for the Eastern District of Louisiana, along with the Criminal Investigation Division of the EPA, has been conducting a federal grand jury investigation of environmental compliance matters relating to surface discharges and reporting on four of our offshore platforms in the Gulf of Mexico. We are fully cooperating with the investigation which began in 2011 and is continuing in 2012. The United States Attorney's Office has informed us that they are continuing their investigation with the intent to seek a criminal disposition. The outcome of this investigation could have a material adverse effect upon us. We are not able at this time to estimate our potential exposure, if any, related to this matter.

On May 6, 2009, certain Cameron Parish land owners filed suit in the 38th Judicial District Court, Cameron Parish, Louisiana against the Company and Tracy W. Krohn as well as several other defendants unrelated to us. In their lawsuit, plaintiffs are alleging that property they own has been contaminated or otherwise damaged by the defendants' oil and gas exploration and production activities and are seeking compensatory and punitive damages. We cannot currently estimate our potential exposure, if any, related to this lawsuit. We are currently, and intend to continue, vigorously defending this litigation.

We have recorded a liability of $2.0 million in the fourth quarter of 2011, which is included in *Other liabilities* on the balance sheet and charged to *General and administrative expenses* ("G&A") in the statement of income (loss), for the loss contingencies of environmental matters that include the events described above and other minor environmental matters we are addressing.

In 2009, the Company recognized $5.3 million in allowable reductions of cash payments for royalties owed to the ONRR for transportation of their deepwater production through our subsea pipeline systems. In 2010, ONRR audited the calculations and support related to this usage fee, and in the third quarter of 2010, we were notified that ONRR 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 ONRR 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.

20. Selected Quarterly Financial Data – UNAUDITED

Unaudited quarterly financial data are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2011				
Revenues	$210,855	$252,922	$245,371	$261,899
Operating income	37,548	115,643	95,333	80,936
Net income	18,649	55,175	52,928	46,065
Basic and diluted earnings per common share (1)	0.25	0.73	0.70	0.61
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 and diluted earnings per common share (1)	0.57	0.37	0.36	0.27

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

21. Supplemental Guarantor Information

Our payment obligations under the Notes and the Credit Agreement (see Note 7) are fully and unconditionally guaranteed by certain of our wholly-owned subsidiaries, Energy VI, which includes the operations of the acquisitions closed in 2010 as described in Note 2, and W&T Energy VII, LLC, which does not have any active operations (together, the “Guarantor Subsidiaries”).

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

Condensed Consolidating Balance Sheet as of December 31, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 4,512	$ —	$ —	$ 4,512
Receivables:				
Oil and natural gas sales	78,131	20,419	—	98,550
Joint interest and other	25,089	—	—	25,089
Insurance	715	—	—	715
Income taxes	74,183	—	(74,183)	—
Total receivables	178,118	20,419	(74,183)	124,354
Deferred income taxes	2,007	—	—	2,007
Prepaid expenses and other assets	30,315	—	—	30,315
Total current assets	214,952	20,419	(74,183)	161,188
Property and equipment – at cost:				
Oil and natural gas properties and equipment	5,689,535	269,481	—	5,959,016
Furniture, fixtures and other	19,500	—	—	19,500
Total property and equipment	5,709,035	269,481	—	5,978,516
Less accumulated depreciation, depletion and amortization	4,208,825	111,585	—	4,320,410
Net property and equipment	1,500,210	157,896	—	1,658,106
Restricted deposits for asset retirement obligations	33,462	—	—	33,462
Deferred income taxes	—	17,637	(17,637)	—
Other assets	372,572	275,181	(631,584)	16,169
Total assets	$2,121,196	$471,133	$(723,404)	$1,868,925
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 73,333	$ 2,538	$ —	$ 75,871
Undistributed oil and natural gas proceeds	33,391	341	—	33,732
Asset retirement obligations	138,185	—	—	138,185
Accrued liabilities	29,705	—	—	29,705
Income taxes	—	84,575	(74,183)	10,392
Total current liabilities	274,614	87,454	(74,183)	287,885
Long-term debt	717,000	—	—	717,000
Asset retirement obligations, less current portion	228,419	27,276	—	255,695
Deferred income taxes	76,518	—	(17,637)	58,881
Other liabilities	280,071	—	(275,181)	4,890
Commitments and contingencies				
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	386,920	231,759	(231,759)	386,920
Retained earnings	181,820	124,644	(124,644)	181,820
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	544,574	356,403	(356,403)	544,574
Total liabilities and shareholders' equity	$2,121,196	$471,133	$(723,404)	$1,868,925

Condensed Consolidating Balance Sheet as of December 31, 2010

	Parent Company	Guarantor Subsidiaries (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, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$697,899	$273,148	$ —	$971,047
Operating costs and expenses:				
Lease operating expenses	182,165	37,041	—	219,206
Production taxes	4,275	—	—	4,275
Gathering and transportation	12,676	4,244	—	16,920
Depreciation, depletion and amortization	214,740	84,275	—	299,015
Asset retirement obligation accretion	26,947	2,824	—	29,771
General and administrative expenses	71,714	2,582	—	74,296
Derivative (gain) loss	(1,896)	—	—	(1,896)
Total costs and expenses	510,621	130,966	—	641,587
Operating income	187,278	142,182	—	329,460
Earnings of affiliates	92,533	—	(92,533)	—
Interest expense:				
Incurred	52,393	—	—	52,393
Capitalized	(9,877)	—	—	(9,877)
Loss on extinguishment of debt	22,694	—	—	22,694
Interest income	84	—	—	84
Income before income tax expense	214,685	142,182	(92,533)	264,334
Income tax expense (benefit)	41,868	49,649	—	91,517
Net income	$172,817	$ 92,533	$(92,533)	$172,817

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

	Parent Company	Guarantor Subsidiaries (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 (gain) 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, 2011

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income (loss)	$ 172,817	$ 92,533	$ (92,533)	$ 172,817
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	241,687	87,099	—	328,786
Amortization of debt issuance costs	2,010	—	—	2,010
Loss on extinguishment of debt	22,694	—	—	22,694
Share-based compensation	9,710	—	—	9,710
Derivative (gain) loss	(1,896)	—	—	(1,896)
Cash payments on derivative settlements	(9,873)	—	—	(9,873)
Deferred income taxes	76,717	(14,882)	—	61,835
Earnings of affiliates	(92,533)	—	92,533	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	(27,709)	9,070	—	(18,639)
Joint interest and other receivables	375	—	—	375
Insurance receivables	20,771	—	—	20,771
Income taxes	(71,655)	64,531	—	(7,124)
Prepaid expenses and other assets	(8,003)	(228,020)	228,214	(7,809)
Asset retirement obligations	(59,958)	—	—	(59,958)
Accounts payable and accrued liabilities	8,589	(514)	(194)	7,881
Other liabilities	227,918	—	(228,020)	(102)
Net cash provided by operating activities	511,661	9,817	—	521,478
Investing activities:				
Acquisition of property interest in oil and natural gas properties	(437,247)	—	—	(437,247)
Investment in oil and natural gas properties and equipment	(277,147)	(4,632)	—	(281,779)
Investment in subsidiary	5,185	—	(5,185)	—
Purchases of furniture, fixtures, misc. sales and other	(3,645)	—	—	(3,645)
Net cash used in investing activities	(712,854)	(4,632)	(5,185)	(722,671)
Financing activities:				
Issuance of 8.5% Senior Notes	600,000	—	—	600,000
Repurchase of 8.25% Senior Notes	(450,000)	—	—	(450,000)
Borrowings of long-term debt – revolving bank credit facility	623,000	—	—	623,000
Repayments of long-term debt – revolving bank credit facility	(506,000)	—	—	(506,000)
Repurchase premium and debt issuance costs	(32,288)	—	—	(32,288)
Dividends to shareholders	(58,756)	—	—	(58,756)
Other	1,094	—	—	1,094
Investment from parent	—	(5,185)	5,185	—
Net cash provided by (used in) financing activities	177,050	(5,185)	5,185	177,050
Decrease in cash and cash equivalents	(24,143)	—	—	(24,143)
Cash and cash equivalents, beginning of period	28,655	—	—	28,655
Cash and cash equivalents, end of period	$ 4,512	$ —	$ —	$ 4,512

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

	Parent Company	Guarantor Subsidiaries (1)	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income (loss)	$ 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	1,338	—	—	1,338
Share-based compensation	5,533	—	—	5,533
Derivative (gain) 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 interest in oil and natural gas properties	—	(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 revolving bank credit facility	627,500	—	—	627,500
Repayments of revolving bank credit facility	(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)
Decrease 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.

22. Supplemental Oil and Gas Disclosures – UNAUDITED

Geographic Area of Operation

All of our proved reserves are located within the United States, with a majority of those reserves located in the Gulf of Mexico and a minority located in Texas. 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, NGLs and natural gas producing activities are as follows (in millions):

	December 31,		
	2011	2010	2009
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 5,775.4	$ 5,130.9	$ 4,637.2
Unproved oil and natural gas properties and equipment	183.6	94.7	95.5
Accumulated depreciation, depletion and amortization related to oil, NGLs and natural gas activities	(4,307.1)	(4,009.9)	(3,743.3)
Net capitalized costs related to producing activities	$ 1,651.9	$ 1,215.7	$ 989.4

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, 2011, by the year in which the costs were incurred (in millions):

	Total	2011	2010	2009	Prior to 2009
Costs excluded by year incurred:					
Acquisition costs	$125.7	$81.3	$ —	$ —	$44.4
Capitalized interest not subject to amortization	28.8	9.6	4.8	4.2	10.2
Total costs not subject to amortization	$154.5	$90.9	$ 4.8	$ 4.2	$54.6

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 (in millions):

	Year Ended December 31,		
	2011	2010	2009
Costs incurred (1):			
Proved property acquisitions	$369.9	$277.3	$ 17.5
Development	203.7	158.3	142.9
Exploration (2) (3)	92.7	70.8	101.6
Unproved property acquisitions (4)	95.1	19.7	12.2
Total costs incurred in oil and gas property acquisition, exploration and development activities	$761.4	$526.1	$274.2

(1) Includes additions (reductions) to our ARO of $32.8 million, $106.1 million and ($6.0) million during the years 2011, 2010 and 2009, respectively, associated with acquisitions, liabilities incurred and revisions of estimates. Refer to Note 5.
(2) Includes seismic costs of $8.0 million, $5.8 million and $6.6 million incurred during the years 2011, 2010 and 2009, respectively.
(3) Includes geological and geophysical costs charged to expense of $6.8 million, $4.3 million and $4.1 million during the years 2011, 2010 and 2009, respectively.
(4) The amounts for 2011, 2010 and 2009 include capitalized interest associated with properties classified as unproved at December 31, 2011, 2010 and 2009, respectively.

Depreciation, depletion, amortization and accretion expense

The following table presents our depreciation, depletion, amortization and accretion expense per million cubic feet equivalent ("Mcfe") of products sold.

	Year Ended December 31,		
	2011	2010	2009
Depreciation, depletion, amortization and accretion per Mcfe	$3.24	$3.38	$3.61

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 may not be comparable to the data for 2009, 2010 and 2011. 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 2009, the following items were affected by the change in the rules. The initial application of these rules resulted in the removal of 3.9 million barrels of oil equivalent ("MMBoe") (23.2 billion cubic feet equivalent ("Bcfe")) in the year 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. 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 (MMBbls) (1)	NGLs (MMBbls) (1)	Natural Gas (Bcf) (1)	Oil Equivalent (MMBoe) (2)	Natural Gas Equivalent (Bcfe) (2)
Proved reserves as of December 31, 2008	40.0	3.9	227.9	81.9	491.1
Revisions of previous estimates (3)	(2.1)	—	(13.0)	(4.3)	(25.4)
Extensions and discoveries (4)	1.2	0.3	14.5	3.9	23.4
Purchase of minerals in place	—	—	0.4	0.1	0.7
Sales of reserves (5)	(1.8)	(0.1)	(12.4)	(4.0)	(24.0)
Production	(6.1)	(1.1)	(51.6)	(15.8)	(94.8)
Proved reserves as of December 31, 2009	31.2	3.0	165.8	61.8	371.0
Revisions of previous estimates (6)	(0.2)	1.2	14.6	3.4	20.2
Extensions and discoveries (7)	1.2	0.5	19.1	4.9	29.2
Purchase of minerals in place (8)	7.7	0.7	101.5	25.3	152.0
Production	(5.9)	(1.2)	(44.7)	(14.5)	(87.0)
Proved reserves as of December 31, 2010	34.0	4.2	256.3	80.9	485.4
Revisions of previous estimates (9)	0.8	5.5	13.5	8.6	51.1
Extensions and discoveries (10)	2.0	0.4	17.7	5.3	32.0
Purchase of minerals in place (11)	20.7	8.9	55.9	39.0	234.1
Production	(6.1)	(1.9)	(53.7)	(16.9)	(101.5)
Proved reserves as of December 31, 2011	51.4	17.1	289.7	116.9	701.1
Year-end proved developed reserves:					
2011	23.4	11.0	251.4	76.4	458.2
2010	23.6	3.4	229.1	65.2	391.3
2009	21.3	2.4	141.3	47.3	283.5
Year-end proved undeveloped reserves:					
2011	28.0	6.1	38.3	40.5	242.9
2010	10.4	0.8	27.2	15.7	94.1
2009	9.9	0.6	24.5	14.5	87.5

(1) Estimated reserves as of December 31, 2011, 2010 and 2009 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. Estimated of reserves as of December 31, 2008 were based on end-of-year prices.

(2) Bcfe and MMBoe are determined using the ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil, condensate or NGLs (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and NGLs may differ significantly from the price per Mcf for natural gas. Similarly, the price per Bbl for oil for may differ significantly from the price per Bbl for NGLs.

(3) Revisions for 2009 included decreases attributable to revised 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. Also included in the revisions of previous estimates for 2009 are negative revisions of 4.7 Bcfe due to performance.

(4) 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.

(5) 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.

(6) Includes revisions due to price of 17.5 Bcfe.

(7) 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.

(8) Primarily due to the properties acquired from Total (Matterhorn and Virgo fields) and the properties acquired from Shell (Tahoe, Southeast Tahoe and Droshky fields).

(9) Includes revision of 6.3 Bcfe due to an increase in average prices, 16.5 Bcfe for a change in NGLs marketing arrangements that allow us to recover a greater percentage of our NGLs from the gas stream, 11.3 Bcfe increase due to additional compression at our Tahoe field that allows us to reduce the drawdown pressure that increases production and ultimate recoveries, and 10.6 Bcfe at Fairway for revisions to reserve estimates from the acquisition date to year end.

(10) Includes discoveries of 13.9 Bcfe at Main Pass 98 and 8.0 Bcfe at Ship Shoal 349/359 and extensions of 3.7 Bcfe at Main Pass 108.

(11) Primarily due to the properties acquired from Opal (the Yellow Rose Properties) and the properties acquired from Shell (the Fairway Properties).

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 December 31, 2011, 2010 and 2009 and period-end commodity prices for December 31, 2008 (beginning of 2009). All prices are adjusted by lease for quality, transportation fees, energy content and regional price differentials. Due to the lack of a benchmark price for NGLs, a ratio is computed for each field of the NGLs realized price compared to the oil realized price. Then, this ratio is applied to the oil price using FASB/SEC guidance. The average commodity prices weighted by field production related to the proved reserves are as follows:

	December 31,			
	2011	2010	2009	2008
Oil – per barrel	$97.36	$76.28	$55.87	$38.85
NGLs – per barrel	51.30	44.92	33.36	25.90
Natural gas – per Mcf	4.11	4.57	3.80	6.17

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 2012 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,		
	2011	2010	2009
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 7,077,206	$ 3,953,655	$2,474,260
Future costs:			
Production	(1,862,488)	(1,011,552)	(604,794)
Development	(543,017)	(243,570)	(212,835)
Dismantlement and abandonment	(513,620)	(520,490)	(496,540)
Income taxes	(1,126,573)	(495,696)	(186,101)
Future net cash inflows before 10% discount	3,031,508	1,682,347	973,990
10% annual discount factor	(1,025,131)	(503,275)	(313,594)
	$ 2,006,377	$ 1,179,072	$ 660,396

	Year Ended December 31,		
	2011	2010	2009
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 1,179,072	$ 660,396	$ 761,682
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(729,574)	(521,551)	(386,331)
Net changes in price, net of future production costs	634,174	367,575	(34,841)
Extensions and discoveries, net of future production and development costs	219,924	143,612	98,087
Changes in estimated future development costs	(4,572)	(59,124)	144,590
Previously estimated development costs incurred	173,911	97,188	224,802
Revisions of quantity estimates	204,988	94,735	(86,600)
Accretion of discount	135,791	68,862	78,789
Net change in income taxes	(398,204)	(221,226)	(32,394)
Purchases of reserves in-place	483,286	624,302	(9,927)
Sales of reserves in-place	—	—	(205,691)
Changes in production rates due to timing and other	107,581	(75,697)	108,230
Net increase (decrease) in standardized measure	827,305	518,676	(101,286)
Standardized measure, end of year	$ 2,006,377	$ 1,179,072	$ 660,396

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, 2011 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, 2011, is set forth in *"Management's Report on Internal Control over Financial Reporting"* included in Part II, Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2011, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included in Part II, Item 8 of this 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, 2011 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 following Item 3 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, effective October 1, 2005, among Kerr-McGee Oil & Gas Corporation, Kerr-McGee Oil & Gas (Shelf) LLC, W&T Offshore, Inc., and W&T Energy V, LLC. (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, effective January 1, 2010, between Total E&P USA Inc. and W&T Offshore, Inc. (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, dated November 3, 2010, between Shell Offshore, Inc., as Seller, and W&T Offshore, Inc. and W&T Energy VI, LLC, as Purchasers. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, filed November 9, 2010)
2.4	Purchase and Sale Agreement, dated April 21, 2011 between Opal Resources, LLC, Opal Resources Operating Company LLC and W&T Offshore, Inc. (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed May 13, 2011)
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))
4.4	Purchase Agreement, dated June 3, 2011, by and among W&T Offshore, Inc., W&T Energy VI, LLC and W&T Energy VII, LLC, and Morgan Stanley & Co. LLC, as representative of the Initial Purchasers. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed June 8, 2011)
4.5	Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 16, 2011)
4.6	Form of 8.5% Senior Notes due 2019. (included in Exhibit 4.4)
4.7	Registration Rights Agreement, dated June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Morgan Stanley & Co. LLC, as representative of the Initial Purchasers. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed June 15, 2011)
10.1**	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors.
10.2*	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))
10.3*	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)
10.4*	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)
10.5*	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)
10.6*	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)

Exhibit Number	Description
10.7*	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)
10.8*	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)
10.9*	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)
10.10*	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)
10.11*	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)
10.12*	Employment Agreement by and between W&T Offshore, Inc. and Jesus G. Melendrez. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 19, 2011)
10.13*	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Jesus G. Melendrez. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed January 19, 2011)
10.14	Fourth Amended and Restated Credit Agreement, dated May 5, 2011, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 6, 2011)
10.15*	Form of the Executive Annual Incentive Award Agreement for Fiscal Year 2011. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011)
12.1**	Ratio of Earnings to Fixed Charges
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.
101.INS**	XBRL Instance Document.

Exhibit Number	Description
101.SCH**	XBRL Schema Document.
101.CAL**	XBRL Calculation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document.
101.LAB**	XBRL Label Linkbase Document.
101.PRE**	XBRL Presentation Linkbase Document.

* 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.

BOEM. Bureau of Ocean Energy Management. The agency is responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

BOEMRE. Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service), was the federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf. The BOEMRE was split into three separate entities: the Office of Natural Resources Revenue; the Bureau of Ocean Energy Management; and the Bureau of Safety and Environmental Enforcement.

BSEE. Bureau of Safety and Environmental Enforcement. The agency is responsible for enforcement of safety and environmental regulations. Previously, this function was managed by the Bureau of Ocean Energy Management, Regulation and Enforcement.

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 and water depths of less than 500 feet.

Deepwater. Water depths greater than 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.

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.

MMBoe. One million barrels of oil equivalent.

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.

NGLs. Natural gas liquids. These are created during the processing of natural gas.

Oil. Crude oil and condensate.

OCS. Outer continental shelf.

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

ONRR. Office of Natural Resources Revenue. The agency assumed the functions of the former Minerals Revenue Management Program, which had been renamed to the Bureau of Ocean Energy Management, Regulation and Enforcement.

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 February 27, 2012.

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 February 27, 2012.

/s/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ JOHN D. GIBBONS **John D. Gibbons**	Senior Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)
/s/ VIRGINIA BOULET **Virginia Boulet**	Director
/s/ SAMIR G. GIBARA **Samir G. Gibara**	Director
/s/ ROBERT I. ISRAEL **Robert I. Israel**	Director
/s/ STUART B. KATZ **Stuart B. Katz**	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, Inc. 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 we have developed significant technical expertise. We recently diversified our operations by expanding onshore into the Permian Basin and into East Texas. We have grown through acquisitions and exploration, hold working interests in approximately 60 producing or capable of producing offshore fields in federal and state waters, and have approximately 173,000 net acres under lease onshore. A substantial majority of our daily production is derived from wells we operate offshore.

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 23, 2012, there were 229 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 Company's 2012 Annual Meeting of Shareholders will be held at 8 a.m. Central Time on May 8, 2012, at the Houston City Club, One City Club Drive, Houston, Texas 77046.

FORM 10-K & QUARTERLY REPORTS/INVESTOR CONTACT

A copy of the W&T Offshore, Inc. Form 10-K for fiscal 2011, 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

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