W&T OFFSHORE INC
Form 10-K
March 04, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

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

(713) 626-8525

(Registrant s telephone number, including area code)

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

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

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

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

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 þ

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 þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

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

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

Large accelerated filer ¨ Accelerated filer þ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company. Yes ¨ No þ

The aggregate market value of the registrant s common stock held by non-affiliates was approximately $330,536,000 based on the closing sale price of $9.46 per share as reported by the New York Stock Exchange on June 30, 2010.

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

DOCUMENTS INCORPORATED BY REFERENCE

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

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

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PART I

Item 1. ***Business***

W&T Offshore, Inc. is a Texas corporation originally organized as a Nevada corporation in 1988, and successor by merger to W&T Oil Properties, Inc., a Louisiana corporation organized in 1983. We are an independent oil and natural gas producer, active in the acquisition, exploitation, exploration and development of oil and natural gas properties primarily in the Gulf of Mexico. This is an area where we have developed significant technical expertise and where high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid return on our invested capital. We have leveraged our historic experience in the conventional shelf (water depths of less than 500 feet) to develop higher impact capital projects in the Gulf of Mexico in both the deepwater (water depths in excess of 500 feet) and the deep shelf (well depths in excess of 15,000 feet and water depths of less than 500 feet). We have acquired rights to develop and exploit new prospects and acquired existing oil and natural gas properties in both the deepwater and the deep shelf, while at the same time continuing our focus on the conventional shelf. We have interests in leases covering approximately 0.9 million gross acres (0.6 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama and onshore. Approximately 82% of our total gross acreage is held-by-production.

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

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. (NSAI) our independent petroleum consultant, our total proved reserves at December 31, 2010 were 485.4 Bcfe. Approximately 81% of our reserves were classified as proved developed and 19% were classified as proved undeveloped. Classified by product, 53% of our reserves were natural gas and 47% were oil and natural gas liquids, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. We calculate that our total proved reserves had a present value of estimated future net revenues discounted at 10% (PV-10) of $1,891.3 million. Our PV-10 after considering future cash outflows related to asset retirement obligations (ARO) and without deducting future income taxes was $1,526.5 million and our standardized measure of discounted future cash flows was $1,179.1 million as of December 31, 2010. For additional information about our proved reserves and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, see Item 2 *Properties Proved Reserves*.

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

During the year 2010, we closed on two major acquisition transactions. On April 7, 2010, we entered into a Purchase and Sale Agreement (PSA) with Total E&P USA (Total) and on April 30, 2010, through our wholly-owned subsidiary, W&T Energy VI, LLC (Energy VI), we acquired all of Total s interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico for a purchase price of $150 million, subject to customary closing adjustments, with an effective date of January 1, 2010. In addition, we assumed the ARO for plugging and abandonment of the acquired interest estimated at $6.3 million. The properties acquired from Total are producing interests with future development potential, and include a 100% working interest in the Matterhorn field (Mississippi Canyon block 243) and a 64% working interest in the Virgo field (Viosca Knoll blocks 822 and 823). The purchase price was adjusted for, among other things, net revenue and operating expenses from the effective date to the closing date, resulting in a net payment of $115.0 million. This acquisition was funded with cash on hand.

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

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

Our exploration efforts historically have been in geographies in fairly close proximity to areas of known proved reserves, which we believe reduces our risks. Historically, we have financed our exploratory drilling with net cash provided by operating activities. The investment associated with drilling a well and future development of a project principally depends upon water depth, the depth of the well, the complexity of the geological formations involved and whether the well or project can be connected to existing infrastructure or will require additional investment in infrastructure. Deepwater and deep shelf drilling projects can be substantially more capital intensive than those on the conventional shelf and onshore. Certain risks are inherent in the oil and natural gas industry and our business, any one of which, if it occurs, can negatively impact our rate of return on shareholders equity. When projects are extremely capital intensive and involve substantial risk, we often seek participants to share the risk. The number of productive wells drilled on a gross basis was 5, 10, and 20 for the years 2010, 2009 and 2008, respectively.

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

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

Our total capital expenditure budget for 2011 is $310 million which excludes acquisitions. The budget includes $161 million of capital to drill and evaluate 14 wells including 10 exploration and four development wells. The 14 wells are comprised of five on the conventional shelf, one in the deepwater, two on the deep shelf of the Gulf of Mexico and six wells located onshore. The budget also includes amounts for well completions, facilities capital, recompletions, seismic and leasehold items. Our acquisition plans thus far in 2011 include acquiring the additional properties from Shell pursuant to the letter of intent which is discussed above. There may be additional acquisitions pursued or completed in 2011 should attractive opportunities arise. We anticipate funding our 2011 capital budget and acquisitions with internally generated cash flow, cash on hand and

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borrowings under our revolving loan facility. Our 2011 capital budget and acquisition plans are subject to change as conditions warrant and our budget is sufficiently flexible such that most any change can be made without penalty. We strive to be as flexible as possible and believe this strategy holds the best promise for value creation and growth and managing the volatility inherent in our business.

Business Strategy

We plan to continue to acquire and exploit oil and natural gas reserves on the Outer Continental Shelf (OCS), the area of our historical success and technical expertise, which we believe will yield rates of return sufficient to remain competitive in our industry. We believe attractive acquisition opportunities will continue to arise in the Gulf of Mexico as the major integrated oil companies and other large independent oil and gas exploration and production companies continue to divest properties to focus on larger and more capital-intensive projects that better match their long-term strategic goals. Because of ongoing market volatility, we also believe that other less well-capitalized producers may seek buyers for their properties both onshore and offshore, which could create opportunities for us.

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

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

We believe our financial approach has contributed to our success and has positioned us to capitalize on new opportunities. Historically, we have limited our annual capital spending for drilling activities to net cash provided by operating activities, and we have used capacity under our credit agreement for acquisitions and to balance working capital fluctuations.

Competition

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

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil and natural gas to third-party purchasers. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, in 2010 we sold over 10% of our production to each of Shell Trading (US) Co. and Conoco Phillips. See Item 8 *Financial Statements Note 1 Significant Accounting Policies Concentration of Credit Risk* for additional information about our sales to these customers. Due to the nature of oil and natural gas markets and because oil and natural gas are freely traded commodities and there are numerous purchasers in the Gulf of Mexico, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production.

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Regulation

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

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

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

Similarly, the natural gas pipeline industry may also be subject to state regulations which may change from time to time. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (Competition Bill) and H.B. 1920 (LUG Bill). The Competition Bill gives the Railroad Commission of Texas (RRC) the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. We note that the RRC is subject to a sunset condition. If the Texas Legislature does not continue the RRC, the RRC will be abolished effective September 1, 2011, and will begin a one-year wind-down process. The Sunset Advisory Commission has recommended certain organizational changes be made to the RRC. We cannot tell what, if any, changes will be

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made to the RRC as a result of the pending regular session or any called sessions of the Texas Legislature in 2011, but we do not believe that any such changes would affect our business in a way that would be materially different from the way such changes would affect our competitors.

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

In December 2007, the FERC issued rules (Order 704) requiring that any market participant, including a producer such as W&T, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation.

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

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

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. The price we receive from the sale of oil and natural gas liquids is affected by the cost of transporting those products to market. Interstate transportation rates for oil, natural gas liquids, and other products are regulated by the FERC. The FERC has established an indexing system for such transportation, which allows such pipelines to take an annual inflation-based rate increase.

In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. As it relates to intrastate crude oil, condensate and natural gas liquids pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally.

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

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits, bonds and pollution liability insurance for the drilling of wells, regulating the location of wells, the

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method of drilling, casing, operating, plugging and abandoning wells, and governing the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation of oil and gas resources, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing of such wells.

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

Federal leases. Most of our operations are conducted on federal oil and natural gas leases, which are administered by the BOEMRE pursuant to the OCSLA. These leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEMRE regulations and orders that are subject to interpretation and change by the BOEMRE. The BOEMRE has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines. See Item 1A, *Risk Factors*, for more information on new regulations.

To cover the various obligations of lessees on the OCS, the BOEMRE generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. The cost of these bonds or assurances can be substantial and there is no assurance that they can be obtained in all cases. We are currently exempt from supplemental bonding requirements by the BOEMRE. As many BOEMRE regulations are being reviewed, we may be subject to supplemental bonding requirements in the future. Under some circumstances, the BOEMRE may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations. See Item 1A, *Risk Factors BP s Deepwater Horizon explosion and ensuing oil spill could have broad adverse consequences affecting our operations in the Gulf of Mexico, some of which may be unforeseeable* for more information.

The BOEMRE also administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the BOEMRE.

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEMRE continues to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEMRE has periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, requirements will be issued by the BOEMRE for future hurricane seasons. New requirements, if any, could increase our operating costs.

Environmental regulations. We are subject to stringent federal, state and local environmental laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and producing operations, the amounts and types of materials that may be released into the environment, the discharge and disposal of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws

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often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. The remediation, reclamation and abandonment of wells, platforms and other facilities are significant costs to us. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

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

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

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

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

In December 2009, the U.S. Environmental Protection Agency (the EPA) determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse

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gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

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

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

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

The Safe Drinking Water Act (the SDWA) regulates, among other things, underground injection operations. Legislation has been proposed in Congress to make the injection of oil and gas well completion fluids

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

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

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

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

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

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

Naturally Occurring Radioactive Materials (NORM) may contaminate minerals, minerals extraction and processing equipment used in the oil and natural gas industry. The waste resulting from such contamination is

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regulated by federal and state laws. Standards have been developed for worker protection; treatment, storage and disposal of NORM and NORM waste; management of waste piles, containers and tanks; and limitations on the relinquishment of NORM contaminated land for unrestricted use under RCRA and state laws. We do not anticipate any material expenditures in connection with our compliance with RCRA and applicable state laws related to NORM waste.

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

Seasonality

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

Employees

As of December 31, 2010, we employed 305 people. We are not a party to any collective bargaining agreements and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other items with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at *www.wtoffshore.com.* These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Investor Relations, W&T Offshore, Inc., Nine Greenway Plaza, Suite 300, Houston, Texas 77046 or by calling (713) 297-8024. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at *www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. ***Risk Factors***

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

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

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

The price we receive for our oil and natural gas production directly affects our revenues, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and are subject to wide price

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fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and will likely continue to be volatile in the future. The prices we receive for our production and the volume of our production depend on numerous factors beyond our control. These factors include the following:

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

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but may also reduce the amount of oil and natural gas that we can produce economically. For example, the prices of oil and natural gas declined substantially during the second half of 2008 and impacted production volumes. Natural gas prices have been negatively affected by the domestic economy, high levels of stored natural gas and weather conditions affecting demand. There have been significant recent development activities in shale and other resource plays, which have the potential to yield a significant amount of natural gas production, and to a lesser extent oil production, in the United States. The potential increases in natural gas supplies resulting from the large-scale development of these unconventional resource reserves could continue to have an adverse impact on the price of natural gas. An environment of depressed oil and natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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

Accounting rules applicable to us require that we periodically review the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. Primarily as a result of the significant decline in both oil and natural gas

prices as of December 31, 2008, we recorded a ceiling test impairment at December 31, 2008 of $1.2 billion. Additionally, we recorded a ceiling test impairment at March 31, 2009 of $218.9 million primarily as a result of a further decline in natural gas prices as of March 31, 2009. We did not have any impairment write-down in 2010. Declines in oil and natural gas prices after December 31, 2010 may require us to record additional ceiling test impairments in the future. No assurance can be given that we will not experience a ceiling test impairment in future periods, which could have a material adverse effect on our results of operations in the period taken. As a result of lower oil and natural gas prices, we may also reduce our estimates of the reserves that may be economically recovered, which would reduce the total value of our proved reserves. See Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Impairment of oil and natural gas properties* and Item 8 *Financial Statements Note 1 Significant Accounting Policies* for a discussion of the ceiling test.

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

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

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

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

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

The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.

The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.

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The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.

The Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

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

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

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

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

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

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

Borrowings under the revolving portion of our Third Amended and Restated Credit Agreement, as amended (the Credit Agreement), are currently limited to $405.5 million. Availability is determined periodically at the discretion of our lenders and is based in part on oil and natural gas prices and in part on our proved reserves. Substantially all of our oil and natural gas properties are pledged as collateral under the Credit Agreement. The Credit Agreement limits our ability to incur additional indebtedness based on specified financial covenants, ratios or other criteria. Lower oil and natural gas prices in the future could result in a reduction in availability and also affect our ability to satisfy these covenants, ratios or other criteria and thus could reduce our ability to incur additional indebtedness and our ability to replace reserves.

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

We could be exposed to uninsured losses in the future. The occurrence of a significant accident or other event not covered in whole or in part by our insurance could have a material adverse impact on our financial condition and operations. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. Because third-party drilling contractors are used to drill our wells, we may not realize the full benefit of workmen s compensation laws in dealing with their employees. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. The insurance market may change dramatically in the future due to the major oil spill that occurred in 2010 as a result of a fire and explosion aboard BP s Deepwater Horizon. We are also exposed to the possibility that we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim.

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

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

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

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operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim.

Hedging transactions may limit our potential gains.

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

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery points assumed in the hedge arrangements; or
- the counterparties to the hedge contracts fail to perform under the terms of the contracts.

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

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

As of December 31, 2010, approximately 19% of our total proved reserves were undeveloped and approximately 32% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

While we have plans for exploiting and producing our proved reserves, there can be no assurance that all of those reserves will ultimately be developed or produced. We are not the operator with respect to approximately 10% of our proved developed non-producing reserves, so we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped and developed non-producing reserves will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

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

Our proved reserves increased in 2010 due to acquisitions but had declined in each of the prior three years. Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. By their nature, estimates of undeveloped reserves are less certain. Recovery of undeveloped reserves could require significant capital expenditures and successful drilling operations. Our future oil and natural gas reserves, production, and therefore our cash flow and net income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

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

Unless we conduct successful development, exploitation and exploration activities at sufficient levels or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves during the initial few years of production. The vast majority of our current operations are in the Gulf of Mexico. Production from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the United States. Our independent petroleum consultant estimates that, on average, 53% of our total proved reserves are depleted within three years. As a result, our need to replace reserves and production from new investments is relatively greater than that of producers who recover lower percentages of their reserves over a similar time period, such as those producers who have a portion of their reserves outside the Gulf of Mexico area. We may not be able to develop, exploit, find or acquire additional reserves in sufficient quantities to sustain our current production levels or to grow production beyond current levels. In addition, due to the significant time requirements involved with exploration and development activities, particularly for wells in the deepwater or wells not located near existing infrastructure, actual oil and natural gas production from new wells may not occur, if at all, for a considerable period of time following the commencement of any particular project.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures and acquisitions with cash on hand, cash provided by operations, securities offerings and bank borrowings. In order to finance future capital expenditures, we may need to alter or increase our capitalization substantially through the issuance of additional debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our financial risk profile.

Future cash flows are subject to a number of variables, such as the level of production from existing wells, the prices of oil and natural gas, and our success in developing and producing new reserves. Any reductions in our capital expenditures to stay within internally generated cash flow (which could be adversely affected by declining commodity prices) and cash on hand will make replacing produced reserves more difficult. If our cash flow from operations and cash on hand are not sufficient to fund our capital expenditure budget, we may not be able to access additional debt, equity or other methods of financing on an economic or timely basis to replace our proved reserves.

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

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors have financial resources that allow them to obtain substantially greater technical expertise and personnel than we have. We actively compete with other companies in our industry when acquiring new leases or oil and natural gas properties. For example, new leases acquired from the BOEMRE are acquired through a sealed bid process and are generally awarded to the highest bidder. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay. On the acquisition opportunities made available to us, we compete with other companies in our industry for such

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properties through a private bidding process, direct negotiations or some combination thereof. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence.

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

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

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

We are required to record a liability for the present value of our ARO to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases to our estimated ARO in future periods. For example, because we operate in the Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimate of future ARO could differ dramatically from what we may ultimately incur as a result of damage from a hurricane.

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

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

As we carry out our drilling program, we may not serve as operator of all planned wells. We have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners and our limited ability to influence operations and associated costs of properties operated by others could prevent the realization of anticipated results in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

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

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

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

Our business involves a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;

natural disasters, such as tropical storms, hurricanes and other adverse weather conditions;

inability to obtain insurance at reasonable rates;

failure to receive payment on insurance claims in a timely manner, or for the full amount claimed;

pipe, cement, subsea well or pipeline failures;

casing collapses;

mechanical difficulties, such as lost or stuck oil field drilling and service tools;

abnormally pressured formations or rock compaction; and

environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, discharges of toxic gases or encountering naturally occurring radioactive materials.

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

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

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

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

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

- severe weather, including tropical storms and hurricanes;
- delays or decreases in production, the availability of equipment, facilities or services;
- changes in the status of pipelines that we depend on for transportation of our production to the marketplace;
- delays or decreases in the availability of capacity to transport, gather or process production; or

changes in the regulatory environment.

Because all our properties could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area. In 2009 and 2008, net production of approximately 8.7 Bcfe and 21.7 Bcfe, respectively, was deferred as a result of damage caused primarily by Hurricane Ike.

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

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

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

Our business strategy includes a continuing acquisition program, which may include acquisitions of exploration and production companies, producing properties and undeveloped leasehold interests. Our acquisition of oil and natural gas properties requires assessments of many factors that are inherently inexact and may be inaccurate, including the following:

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

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

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

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

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

customer or key employee loss from the acquired business;

increased administration of new personnel;

additional costs due to increased scope and complexity of our operations; and

potential disruption of our ongoing business.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological

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characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties in our primary operating region or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as with acquisitions within our primary operating region. We may not be successful in addressing these risks or any other problems encountered in connection with any acquisition we may make.

Estimates of our proved reserves depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in the estimates or underlying assumptions will materially affect the quantities of and present value of future net revenues from our proved reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of our reserves at December 31, 2010. See Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Oil and natural gas reserve quantities* for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in Item 1 *Business,* Item 2 *Properties* and Item 8 *Financial Statements Note 21 Supplemental Oil and Gas Disclosures*.

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

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

You should not assume that the present value of future net revenues from our proved oil and natural gas reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month unweighted first-day-of-the-month average price for each product and costs in effect on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

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

A prospect is a property in which we own an interest or have operating rights and have what our geoscientists believe, based on available seismic and geological information, to be indications of economic accumulation of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analysis we perform using data from other wells, more fully explored prospects and/or producing fields will accurately predict the characteristics and potential reserves associated with our drilling prospects. To the extent we drill additional wells in the deepwater

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and/or on the deep shelf, our drilling activities could become more expensive. In addition, the geological complexity of deepwater, deep shelf and various onshore formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, there can be no assurance that we will find commercial quantities of oil and natural gas and, therefore, there can be no assurance that we will achieve positive rates of return on our investments.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities, which in most cases are owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells because of a reduction in demand for our production or because of inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market. We have, in the past, been required to shut in wells when hurricanes have caused or threatened damage to pipelines and gathering stations. In September 2008, as a result of Hurricane Ike, two of our operated platforms and eight non-operated platforms were toppled and a number of platforms, third-party pipelines and processing facilities upon which we depend to deliver our production to the marketplace were damaged.

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

Currently, a portion of our oil and natural gas is processed for sale on platforms owned by parties with no economic interest in our wells and no other processing facilities would be available to process such oil and natural gas without significant investment by us. In addition, third-party platforms could be damaged or destroyed by hurricanes which could reduce or eliminate our ability to market our production. As of December 31, 2010, five fields, accounting for approximately 2.9 Bcfe (or 3%) of our 2010 production, are tied back or are planned to be tied back to separate, third-party owned platforms. There can be no assurance that the owners of such platforms will continue to process our oil and natural gas production. If any of these platform operators ceases to operate their processing equipment, we may be required to shut in the associated wells.

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

We depend upon third-party pipelines that provide delivery options from our facilities. Because we do not own or operate these pipelines, their continued operation is not within our control. If any of these third-party pipelines become partially or fully unavailable to transport natural gas and oil, or if the gas quality specification for the natural gas pipelines changes so as to restrict our ability to transport natural gas on those pipelines, our revenues could be adversely affected. For example, damage caused primarily by Hurricane Ike to third-party pipelines and other facilities resulted in deferred net production of approximately 8.7 Bcfe and 21.7 Bcfe for the years 2009 and 2008, respectively. Another example is a third-party pipeline used by our Main Pass 108 field has been shut in since June 2010, which we believe has caused approximately 4.9 Bcfe of production to be deferred during 2010.

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

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

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

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

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

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

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

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

require the acquisition of a permit before drilling commences;

restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;

limit or prohibit exploration or drilling activities on certain lands lying within wilderness, wetlands and other protected areas or that may affect certain wildlife, including marine mammals; and

impose substantial liabilities for pollution resulting from our operations.

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

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

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

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

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

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

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

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse

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gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Please see *Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.*

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

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

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

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

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

To a large extent, we depend on the services of our senior management. The loss of the services of any of our senior management, including Tracy W. Krohn, our Founder, Chairman and Chief Executive Officer; Jamie L. Vazquez, our President; John D. Gibbons, our Senior Vice President, Chief Financial Officer and Chief Accounting Officer; Stephen L. Schroeder, our Senior Vice President and Chief Operating Officer, Jesus G. Melendrez, our Senior Vice President and Chief Commercial Officer, and Thomas F. Getten, our Vice President, General Counsel and Assistant Secretary, could have a negative impact on our operations. We do not maintain or plan to obtain any insurance against the loss of any of these individuals. Please read Part I *Executive Officers of the Registrant* included in this Annual Report on Form 10-K for more information regarding certain members of our management team.

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

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

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

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

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

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

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by any adverse changes in economic or other conditions. In recent years, market conditions resulting in downgrades to credit ratings of energy merchants affected the liquidity of several of our purchasers.

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Risks Related to Financings

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

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

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

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

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

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

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

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

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

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

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

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

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

Risks Related to Our Principal Shareholder, Tracy W. Krohn

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

Tracy W. Krohn controls 39,234,187 shares of our common stock, representing approximately 52.7% of our voting interests as of February 25, 2011. As a result, Mr. Krohn has the ability to control the outcome of virtually all matters requiring shareholder approval and other investors, by themselves, will not be able to affect the outcome of virtually any shareholder vote. Mr. Krohn, subject to any duty owed to our minority shareholders under Texas law, is able to control all matters affecting us, including:

- the composition of our board of directors and, through it, any determination with respect to our business direction and policies, including the appointment and removal of officers;
- the determination of incentive compensation, which may affect our ability to retain key employees;
- any determinations with respect to mergers or other business combinations;

our acquisition or disposition of assets;

our financing decisions and our capital raising activities;

our payment of dividends on our common stock; and

amendments to our amended and restated articles of incorporation or bylaws.

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

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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.

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Item 2. ***Properties***

Substantially all of our fields are located in the Gulf of Mexico. These fields are found in water depths ranging from less than ten feet up to 4,200 feet. The reservoirs in our fields are generally characterized as having high porosity and permeability, which typically result in high production rates. The following describes our ten largest fields as of December 31, 2010, based on quantities of proved reserves on a natural gas equivalent basis. At December 31, 2010, these fields accounted for approximately 77% of our proved reserves.

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

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

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

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

Ship Shoal 349 Field. Ship Shoal 349 field is located off the coast of Louisiana, approximately 235 miles southeast of New Orleans, in 375 feet of water. The field area covers Ship Shoal blocks 349 and 359, with a single production platform on Ship Shoal block 349. Phillips Petroleum discovered the field in 1993. We initially acquired a 25% working interest in the field from BP in 1999. In 2003, we acquired an additional 34% working interest through a transaction with ConocoPhillips that increased our working interest to approximately 59%, and we became the operator of the field in December 2004. In early 2008, we acquired the remaining working interest from Apache Corporation and we now own a 100% working interest in this field. Cumulative field production through 2010 is approximately 176 Bcfe gross. This field is a sub-salt development with five productive horizons below salt at depths ranging to 17,000 feet. As of December 31, 2010, 22 wells have been drilled, of which 13 have been successful. During 2010, we developed a reservoir simulation model to determine the most optimal future development plan. As a result, in 2011, we plan to drill two development wells. Total proved reserves associated with our interest in this field were 113.3 Bcfe at December 31, 2010.

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

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

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

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

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

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

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

The following is a description of the remainder of our top ten properties, measured by proved reserves at December 31, 2010, of which five are located on the conventional shelf, two are located in the deepwater and one is located on the deep shelf. We do not believe that individually any of these properties are of major significance (each has proved reserves which comprise less than 15% of the Company s total proved reserves, calculated on a natural gas equivalent basis).

Main Pass 108 Field. Main Pass 108 field consists of Main Pass blocks 94, 107, 108 and 109. This field is located off the coast of Louisiana approximately 50 miles east of Venice in 50 feet of water. We acquired our working interests in these blocks, which range from 33% to 100%, in a transaction with Kerr-McGee Oil and Gas Corporation. The field produces from a number of low relief, predominantly stratigraphically trapped sands. The productive interval ranges in age from Upper Miocene Big A through Middle Miocene Big Hum. As of December 31, 2010, 52 wells have been drilled in this field, of which 38 were successful. Cumulative field production through 2010 is approximately 283 Bcfe gross. During 2010, additional wells were successfully drilled, recompleted or workovers were performed to increase production and add reserves. However, the third party pipeline that is used to transport production from the field has been shut in since June 2010. We currently expect production from the field to resume in the first half of 2011.

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

Viosca Knoll 823 Field. (Virgo) Viosca Knoll 823 field is located off the coast of Louisiana, approximately 125 miles southeast of New Orleans, in 1,014 feet of water. The field area covers Viosca Knoll block 823 and Viosca Knoll block 822, with a single production platform on Viosca Knoll block 823. Total discovered the field in 1997. We acquired a 64% working interest in the field from Total in 2010. Cumulative field production through 2010 is approximately 115 Bcfe gross. This field is a supra-salt development with 17 productive horizons at depths ranging to 13,335 feet. As of December 31, 2010, 12 wells have been drilled, of which 10

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have been successful. During December 2010, production from this field, net to our interest, averaged 3.9 MMcf of natural gas per day and 170 Bbls of oil per day, or 4.9 MMcfe per day.

Brazos A-133 Field. Brazos A-133 field is located 85 miles east of Corpus Christi, Texas in 200 feet of water. The field was discovered in 1978 by Cities Service Oil Company with production commencing in the same year. There are five active platforms, three of which are production platforms. Cumulative field production through 2010 is approximately 849 Bcfe gross from the Middle Miocene Tex W and Big Hum sections. The bulk of the production is from the Big Hum CM-7 sand, which is a 4-way closure downthrown to the Corsair Fault and bisected by antithetic faults. The top of the CM-7 sand is at a subsea depth of 12,000 feet. Since its discovery, 22 wells have been drilled, of which 17 were successful. We own a 25% working interest that was obtained through a transaction with Kerr-McGee. During December 2010, production from this field, net to our interest, averaged 6.7 MMcf of natural gas per day and 18 Bbls of oil per day, or 6.8 MMcfe per day.

Main Pass 283 Field. Main Pass 283 field consists of Main Pass blocks 284, 279 and 283 and Viosca Knoll Block 734. This field is located off the coast of Louisiana approximately 75 miles east of Venice in 315 feet of water. We acquired our working interests in these blocks, which range from 50% to 100%, in a transaction with ConocoPhillips. The field produces from a number of low relief, predominantly stratigraphically trapped sands. The productive interval ranges in age from Upper Miocene Big A through Middle Miocene Cristellaria I. As of December 31, 2010, 12 wells have been drilled in this field, of which 10 were successful. Cumulative field production through 2010 is approximately 141 Bcfe gross. During December 2010, production from this field, net to our interest, averaged 10.2 MMcf of natural gas per day and 1,136 Bbls of oil per day, or 17.0 MMcfe per day.

West Delta 30 Field. West Delta 30 field is located approximately six miles off the coast of Louisiana in 40 feet of water. Our interests in this field are in West Delta Block 29, which straddles the eastern side of a major piercement salt dome with large accumulations of oil and natural gas sands found in traps along the salt flanks. In 1997, we entered into a farmout agreement with Chevron to further explore and develop potential reserves. Following a thorough 3-D seismic analysis, we have drilled a total of 17 exploration and development wells, all but one of which have been successful. Our working interests in these wells range from 75% to 100%. Cumulative field production through 2010 is approximately 703 Bcfe gross. During December 2010, production from this field, net to our interest, averaged 0.1 MMcf of natural gas per day and 262 Bbls of oil per day, or 1.7 MMcfe per day. We currently have rig interventions scheduled in 2011, which we expect will increase the production from this field.

Mobile 823 Field. Mobile 823 field is located off the coast of Alabama in approximately 60 feet of water. It is a natural gas field comprised of two OCS blocks, Mobile Blocks 822 and 823. The field was discovered by Mobil Oil Corporation in 1983, with initial production commencing in 1991. We acquired our 12.5% working interest in 2003 from ConocoPhillips. ExxonMobil currently operates the majority of the field. We operate one well, a Miocene Luce sand discovery drilled in 2006. Production is primarily from the Jurassic Norphlet sandstone at 21,500 feet, with minor production from Miocene sands at 3,000 to 7,000 feet. The trapping mechanism is a combination structural and stratigraphic trap. Cumulative field production through 2010 is approximately 797 Bcfe gross from eleven productive wells. The field has one processing platform and three independent structures. During December 2010, production from this field, net to our interest, averaged 3.7 MMcf of natural gas per day and 169 Bbls of oil per day, or 4.7 MMcfe per day.

East Cameron 321 Field. East Cameron 321 field is located approximately 97 miles off the Louisiana coastline in 225 feet of water. Two production facilities, the A and B platforms, are located on the block. This field has multiple sands that are productive in faulted, structural traps. As of December 31, 2010, 75 wells have been drilled of which 57 have been successful. Cumulative field production through 2010 is approximately 552 Bcfe gross. We own a 100% working interest in the field and are the operator of the field. During December 2010, production from this field, net to our interest, averaged 1.9 MMcf of natural gas per day and 1,520 Bbls of oil per day, or 11.0 MMcfe per day.

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Proved Reserves

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

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

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

(1) One billion cubic feet equivalent (Bcfe) and one million barrel equivalent (MMBoe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. Similarly, the price per barrel for oil and natural gas liquids may differ significantly from the price per Boe for natural gas.

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

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

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

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

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

Changes in Proved Reserves

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

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2010 included in this Annual Report on Form 10-K was prepared by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The scope and results of their procedures are summarized in a letter included as an exhibit to this Annual Report on Form 10-K. The primary technical person at NSAI responsible for overseeing the preparation of the reserves estimates presented herein has B.S. and M.S. degrees in Civil Engineering and has been a Registered Professional Engineer in the State of Texas for 22 years and a member of the Society of Petroleum Engineers for over 26 years. He has over 33 years total experience in the oil and gas industry, with over 19 years of reservoir engineering experience. His areas of experience are the continental shelf and deepwater Gulf of Mexico, San Juan Basin, onshore and offshore Mexico, offshore Africa, and unconventional gas sources worldwide. NSAI has

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informed us that he meets or exceeds the education, training, and experience requirements set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

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

Reserve Technologies

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

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

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered.

Reporting of Oil and Natural Gas Production and Reserves

We produce natural gas liquids as part of the processing of our natural gas. The extraction of natural gas liquids in the processing of natural gas reduces the volume of natural gas available for sale. In our December 31, 2010 reserve report prepared by our independent petroleum consultant, natural gas liquids represented approximately 5% of our total proved reserves. Natural gas liquids are products sold by the gallon. Therefore, in reporting reserve and production amounts of natural gas liquids, we include natural gas liquids in the oil category using a ratio of 42 gallons/barrel. Prices for natural gas liquids in 2010 were approximately 44% lower on average than prices for equivalent volumes of oil. Natural gas liquids accounted for 17% of our combined reported production for oil, condensate and natural gas liquids combined. We report our average oil prices realized after taking into account the effect of the lower prices received for sales of natural gas liquids. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of natural gas liquids.

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Development of Proved Undeveloped Reserves

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

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

Acreage

The following summarizes gross and net developed and undeveloped acreage at December 31, 2010. Net acreage is our percentage ownership of gross acreage. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	611,195	370,292	97,988	84,879	709,183	455,171
Deepwater	85,952	50,470	51,840	43,200	137,792	93,670
Total Offshore	697,147	420,762	149,828	128,079	846,975	548,841
Onshore			6,628	4,644	6,628	4,644
Total	697,147	420,762	156,456	132,723	853,603	553,485

Approximately 82% of our total gross acreage is held-by-production, which permits us to maintain all of our exploration, exploitation and development rights (including deep rights below currently producing zones) to the leased area as long as production continues. We have the right to propose future exploration and development projects, including deep exploration projects, on the majority of our acreage.

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

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

Production

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

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Production History

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

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

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

Refer to the descriptions of our ten largest fields earlier in Item 2 *Properties* for historical information about our produced oil and natural gas volumes from our Ship Shoal 349 field and Viosca Knoll 783 field over the past three fiscal years, which have proved reserves comprising 15% or more of our total proved reserves. Also refer to Item 6 *Selected Financial Data - Historical Reserve and Operating Information* for additional historical operating data.

Productive Wells

The following presents our ownership interest at December 31, 2010 in our productive oil and natural gas wells, including wells that were temporarily shut-in on that date primarily because of two pipeline outages impacting several fields, including our Main Pass 108 field. A net well is our percentage working interest of a gross well.

	Oil Wells (1)		Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	99	86.5	116	96.6	215	183.1
Non-operated	60	21.2	90	18.3	150	39.5
	159	107.7	206	114.9	365	222.6

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

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

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

Drilling Activity

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

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The level of our investment in oil and gas properties changes from time to time depending on numerous factors, including the prices of oil and natural gas, acquisition opportunities and the results of our exploration and development activities. For the year ended December 31, 2010, our capital expenditures for oil and natural gas properties and equipment of $415.7 million included $60.2 million for exploration activities, $77.2 million for development activities and $41.3 million for seismic, capitalized interest and other leasehold costs.

Development Drilling

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Gross Wells:			
Productive	1	2	2
Non-productive		1	
	1	3	2
Net Wells:			
Productive	0.1	1.7	1.7
Non-productive		0.5	
	0.1	2.2	1.7

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

Exploration Drilling

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

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

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

Current Drilling Activity

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

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Item 3. ***Legal Proceedings***

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

Executive Officers of the Registrant

The following lists our executive officers:

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

Ages as of February 18, 2011.

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

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

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

John D. Gibbons joined the Company in February 2007 as Senior Vice President and Chief Financial Officer. In September 2007, he assumed the additional position of Chief Accounting Officer. Prior to joining the Company, Mr. Gibbons was Senior Vice President and Chief Financial Officer of Westlake Chemical Corporation from March 2006 to February 2007. Prior to joining Westlake, Mr. Gibbons was with Valero Energy Corporation for 23 years, holding positions of increasing responsibility ending as Executive Vice President and Chief Financial Officer.

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

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

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

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PART II

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

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

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

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

Dividends

Under the Credit Agreement as amended, we are allowed to pay annual dividends or make share repurchases of up to $60 million per year if we are not in default. In addition, the indenture governing the 8.25% Senior Notes (the Senior Notes) contains restrictions on the payment of dividends unless we meet the restricted payment tests in the indenture. See Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources* and Item 8 *Financial Statements Note 7 Long-Term Debt* for more information regarding our Credit Agreement and the indenture governing the Senior Notes.

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

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

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

With the exception of any special cash dividends, we currently expect that comparable cash dividends will continue to be paid in the future, subject to periodic reviews of the Company s performance by our board of

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

Stock Performance Graph

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

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

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Issuer Purchases of Equity Securities

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

The following table sets forth information about shares delivered by employees during the quarter ended December 31, 2010 to satisfy tax withholding obligations on the vesting of restricted shares.

Period		Total Number of Shares Delivered	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2010	October 31, 2010	N/A	N/A	N/A	N/A
November 1, 2010	November 30, 2010	N/A	N/A	N/A	N/A
December 1, 2010	December 31, 2010	142,268	$ 16.95	N/A	N/A

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

SELECTED HISTORICAL FINANCIAL INFORMATION

The selected historical financial information set forth below should be read in conjunction with Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations* and with Item 8 *Financial Statements*.

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

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

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

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

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

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

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

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

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

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

(9) Consists primarily of interest income.

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

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HISTORICAL RESERVE AND OPERATING INFORMATION

The following presents summary information regarding our estimated net proved oil and natural gas reserves and our historical operating data for the years shown below. All calculations of estimated proved reserves have been made in accordance with the rules and regulations of the SEC and give no effect to federal or state income taxes. For additional information regarding our estimated proved reserves, please read Item 1 *Business* and Item 2 *Properties.* The selected historical operating data set forth below should be read in conjunction with Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations* and with Item 8 *Financial Statements*.

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

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

(2) One billion cubic feet equivalent (Bcfe), one million cubic feet equivalent (MMcfe) and one thousand cubic feet equivalent (Mcfe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas.

(3) Approximately 29.6 Bcfe of reserves were shut-in at December 31, 2010 due to two pipeline outages impacting several fields, including our Main Pass 108 field. Approximately 1.7 Bcfe and 53.9 Bcfe of reserves were shut-in at December 31, 2009 and 2008, respectively, because of damage caused by Hurricane Ike in September 2008. Approximately 20.2 Bcfe of reserves were shut-in at December 31, 2006 because of Hurricanes Katrina and Rita in 2005. Also, approximately 5.7 Bcfe of reserves were shut-in at December 31, 2006 because of damage to the High Island Pipeline System which occurred in December 2006.

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

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

(1) One billion cubic feet equivalent (Bcfe), one million cubic feet equivalent (MMcfe) and one thousand cubic feet equivalent (Mcfe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas.

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

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

The following discussion and analysis should be read in conjunction with Item 8 *Financial Statements*. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this annual report.

Overview

We are an independent oil and natural gas producer focused primarily in the Gulf of Mexico. We have grown through acquisitions, exploitation and exploration and currently hold working interests in approximately 67 producing fields in federal and state waters. We operate wells accounting for approximately 73% of our average daily production. In recent years, we have acquired interests in acreage and wells in the deepwater (more than 500 feet of water) on the outer continental shelf. We have interests in leases covering approximately

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0.9 million gross acres (0.6 million net acres) spanning primarily across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama and minor holdings onshore. We own interests in approximately 267 structures, 159 of which are located in fields that we operate.

In managing our business, we are concerned primarily with maximizing return on shareholders equity. To accomplish this primary goal, we focus on profitably increasing production and reserves. We strive to grow our reserves through acquisitions and our drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to continue to add reserves post-acquisition.

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

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

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

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

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil and natural gas production and the price that we receive for such production. In 2010, our production volume was comprised of approximately 49% oil, condensate and natural gas liquids and 51% natural gas, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. During 2010, we sold an average of approximately 122 MMcf of natural gas per day and approximately 19,000 Bbls of oil per day, or a combined rate of 238 MMcfe per

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day. Most of the production that was affected by Hurricane Ike in 2008 and 2009 was restored by 2010. One major field, Main Pass 108, has had production curtailed since June 2010 due to the third-party pipeline outage and we anticipate production from the field to resume in the first half of 2011.

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

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