CROSS BORDER RESOURCES, INC.
Form 10-K
April 01, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the year ended December 31, 2012

OR

o 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 000-52738

CROSS BORDER RESOURCES, INC.
(Exact Name of Registrant as Specified in Its Charter)

Nevada (State or Other Jurisdiction of Incorporation or Organization)	98-0555508 (I.R.S. Employer Identification No.)
2515 McKinney Avenue, Suite 900 Dallas, TX (Address of Principal Executive Offices)	75201 (Zip Code)
(Registrant's Telephone Number, Including Area Code)	(210) 226-6700
Securities registered pursuant to Section 12(b) of the Act:	None
Securities registered pursuant to Section 12(g) of the Act:	Common Stock, par value $.001 (Title of class)

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

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

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 requirement for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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. (Check one):

Large accelerated filer	o	Accelerated filer	o
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

As of June 30, 2012 (the last business day of the registrant's most recently completed second fiscal quarter), the aggregate market value of the registrant's common stock (based on a reported closing market price of $1.60 per share on the OTCBB) held by non-affiliates of the registrant was approximately $12,948,916. For purposes of this computation, all officers, directors and 10% beneficial owners of the registrant are deemed to be affiliates. Such determination should not be deemed to be an admission that such officers, directors or 10% beneficial owners are, in fact, affiliates of the registrant.

As of April 1, 2013, there were 16,301,946 shares of common stock, $.001 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

CROSS BORDER RESOURCES, INC.
FORM 10-K

TABLE OF CONTENTS

Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Statements that are not historical facts, including statements about our beliefs and expectations, are forward-looking statements. Forward-looking statements include statements preceded by, followed by or that include the words "may," "could," "would," "should," believe," "expect," anticipate," "plan," "estimate," "target," "project," "intend," similar expressions and the negative of such words and expressions, although not all forward-looking statements contain such words or expressions.

Forward-looking statements are only predictions and are not guarantees of performance. These statements generally relate to our plans, objectives and expectations for future operations and are based on management's current beliefs and assumptions, which in turn are based on its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. Although we believe that the plans, objectives and expectations reflected in or suggested by the forward-looking statements are reasonable, there can be no assurance that actual results will not differ materially from those expressed or implied in such forward-looking statements. Forward-looking statements also involve risks and uncertainties. Many of these risks and uncertainties are beyond our ability to control or predict and could cause results to differ materially from the results discussed in such forward-looking statements. Such risks and uncertainties include, but are not limited to, the following:

- our ability to raise additional capital to fund future capital expenditures;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop and produce our oil and natural gas properties;
- declines or volatility in the prices we receive for our oil and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- risks associated with drilling, including completion risks, cost overruns and the drilling of non-economic wells or dry holes;
- uncertainties associated with estimates of proved oil and natural gas reserves;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- risks and liabilities associated with acquired companies and properties;
- risks related to integration of acquired companies and properties;
- potential defects in title to our properties;
- cost and availability of drilling rigs, equipment, supplies, personnel and oilfield services;
- geological concentration of our reserves;

- environmental or other governmental regulations, including legislation of hydraulic fracture stimulation;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- exploration and development risks;
- management's ability to execute our plans to meet our goals;
- our ability to retain key members of our management team;
- weather conditions;
- actions or inactions of third-party operators of our properties;

- costs and liabilities associated with environmental, health and safety laws;
- our ability to find and retain highly skilled personnel;
- operating hazards attendant to the oil and natural gas business;
- competition in the oil and natural gas industry; and
- the other factors discussed under Item 1A. "Risk Factors" in this report.

Forward-looking statements speak only as of the date hereof. All such forward-looking statements and any subsequent written and oral forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this section and any other cautionary statements that may accompany such forward-looking statements. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements.

Glossary of Oil and Natural Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this Annual Report on Form 10-K.

"Bbl" One stock tank barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

"Boe" One barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil and 42 gallons of natural gas liquids to one Bbl of oil.

"Boe/d" Boe per day.

"Btu" A British thermal unit is a measurement of the heat generating capacity of natural gas. One Btu is the heat required to raise the temperature of a one-pound mass of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

"completion" The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting of abandonment to the appropriate agency.

"condensate" A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"developed acreage" The number of acres that are allocated or assignable to productive wells or wells capable of production.

"development costs" Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, natural gas lines, and power lines, to the extent necessary in developing the proved reserves;

- drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

- acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

- provide improved recovery systems.

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

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

"exploration costs" Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells.

“exploratory well” A well drilled for the purpose of discovering new reserves in unproven areas.

“field” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“formation” A layer of rock which has distinct characteristics that differ from nearby rock.

“gross acres” The total acres in which a working interest is owned.

“Henry Hub” The pricing point for natural gas futures contracts traded on the NYMEX.

“horizontal well” A well that is drilled vertically to a certain depth and then drilled at a right angle within a specific interval.

“hydraulic fracturing” or “fracing” A process involving the injection of fluids, usually consisting mostly of water, but typically including small amounts of sand and other chemicals, in order to create fractures extending from the wellbore through the rock formation to enable oil or natural gas to move more easily through the rock pores to a production well.

“lease operating expenses” The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBoe” One thousand barrels of oil equivalent.

“Mcf” One thousand cubic feet of natural gas.

“Mcf/d” One thousand cubic feet of natural gas per day.

“MMBoe” One million barrels of oil equivalent.

“MMBtu” One million British thermal units.

“MMcf” One million cubic feet of natural gas.

“natural gas” Natural gas and natural gas liquids.

“net acres” The sum of the fractional working interests owned in gross acres.

“NYMEX” The New York Mercantile Exchange.

“oil” Oil and condensate.

“overriding royalty interest” An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

“PDP” Proved developed producing reserves.

6

“PDNP” Proved developed non-producing reserves.

“play” A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential natural gas and oil reserves.

“plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

“producing well” A well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

“production costs” Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and natural gas produced. Examples of production costs (sometimes called lifting costs) are:

- costs of labor to operate the wells and related equipment and facilities;
- repairs and maintenance;
- materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities;
- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and
- severance taxes.

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

“proved developed reserves” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“proved properties” Properties with proved reserves.

“proved reserves” Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, or LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, or HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

“proved undeveloped reserves” Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

“PUD” Proved undeveloped reserves.

“PV-10” When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.

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

“recompletion” The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

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

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

“sand” A geological term for a formation beneath the surface of the Earth from which hydrocarbons are produced. Its make-up is sufficiently homogenous to differentiate it from other formations.

“shale” Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

“spacing” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

“standardized measure” The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

“stratigraphic test well” A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production.

“undeveloped acreage” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

“vertical well” An oil or natural gas wellbore that is drilled from the surface to the depth of interest without directional deviation.

“wellbore” The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

“working interest” The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploitation, development, and operating costs on either a cash, penalty, or carried basis.

PART I

Item 1. Business

Our Company

We are an oil and gas exploration company. We currently own over 865,893 gross (approximately 293,843 net) mineral and lease acres in New Mexico and Texas. Approximately 25,000 of these net acres exist within the Permian Basin. A significant majority of our acreage consists of either owned mineral rights or leases held by production, allowing us to hold lease rental payments to under $5,000 annually. The majority of our acreage interests consists of non-operated working interests except for certain core San Andres properties which we operate.

Current development of our acreage is focused on our prospective Bone Spring acreage located in the heart of the 1st and 2nd Bone Spring play. This play encompasses approximately 4,390 square miles across both New Mexico and Texas. We currently own varying, non-operated working interests in both Eddy and Lea Counties, New Mexico, along with our working interest partners that include Cimarex, Apache, Oxy Permian, Occidental, Oxy USA and, Mewbourne; all having significant footprints within this play, and are adding to those footprints through lease and corporate acquisitions.

History

We were originally formed on October 25, 2005 under the name “Language Enterprises Corp.” We subsequently changed our name to Doral Energy Corp. On July 29, 2008, we acquired a working interest in 66 producing oil fields and approximately 186 wells (the “Eddy County Properties”) in and around Eddy County, New Mexico. As a result of our acquisition of the Eddy County Properties, we changed our business focus to the acquisition, exploration, operation and development of oil and gas projects, and we ceased being a “shell company.” On August 4, 2008, we filed our Form 8-K that included the information that would be required if we were filing a general form for registration of securities on Form 10 as a smaller reporting company.

Effective January 3, 2011, we completed the acquisition of Pure Energy Group, Inc. as contemplated pursuant to the Pure Merger Agreement among our company, Doral Sub, Pure L.P. and Pure Sub, a wholly owned subsidiary of Pure L.P. Pursuant to the provisions of the Pure Merger Agreement, all of Pure L.P.’s oil and gas assets and liabilities were transferred to Pure Sub. Pure Sub was then merged with and into Doral Sub, with Doral Sub continuing as the surviving corporation. Upon completion of the Pure Merger, the outstanding shares of Pure Sub were converted into an aggregate of 9,981,536 shares of our common stock. Since the Pure Merger, Pure L.P. has distributed all of its shares of our common stock to the partners of Pure L.P. so that Pure L.P. is no longer a shareholder of our company.

Effective January 4, 2011, following closing of the Pure Merger, Doral Sub was merged with and into our company, with our company continuing as the surviving corporation. Upon completing the merger of Doral Sub with and into our company, we changed our name to “Cross Border Resources, Inc.”

Our Strengths

Large Acreage Position Consisting of Mineral Ownership and Leasehold Held by Production. Our acreage consists of more than 290,000 net mineral acres within the Permian Basin region of New Mexico and Southwest New Mexico. The majority of our acreage is made up of mineral ownership which carries no drilling commitments or leasehold obligations. We own minerals in both the Permian Basin region and Southwest New Mexico. Cross Border’s producing leasehold acreage is located entirely within the active Permian Basin region and is currently held by existing production. The combination of perpetual mineral ownership and unexpired leasehold held by production uniquely positions us as a strong Permian Basin exploration and production company with continued growth potential.

Existing Infrastructure. All of our producing Permian properties are located within established oil and natural gas producing areas or existing fields. We seek to enhance existing production in these properties by using engineering and geological expertise. These areas also have a fully developed transportation infrastructure, which allows us to transport our oil and natural gas to market without long-term delay or significant investment.

Our Properties

Currently, substantially all of our producing oil and natural gas properties are concentrated in the Permian Basin. The Permian Basin covers an area approximately 250 miles wide and 300 miles long in West Texas and Southeast New Mexico. The Permian Basin is one of the most prolific onshore oil and natural gas producing regions in the United States. It is characterized by an extensive production history, mature infrastructure, long reserve life and hydrocarbon potential in multiple producing formations.

Planned Operations

We plan to spend between $8 million and $12 million during fiscal 2013 to drill and complete wells, re-enter and complete wells, or improve infrastructure. Our main area of focus is the Tom Tom/Tomahawk Prospect, where we will begin work on the field alongside the execution of our remediation plan, described below. For fiscal 2013, this included the re-entry of 14 gross wells (11.7 net), drilling of 6 gross wells (5.2 net), and the improvement of field infrastructure. We will also spend capital in several non-operated prospect areas. Currently, we are committed to participating in the drilling of 12 gross wells (1.1 net) in fiscal 2013. We expect to finance these activities with cashflow generated from operations and availability under our line of credit with Independent Bank.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources than we do. The largest of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in our drilling and development operations, locating and acquiring prospective oil and natural gas properties and reserves and attracting and retaining highly skilled personnel. There is also competition between producers of oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the United States government; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Insurance

We currently maintain oil and gas commercial general liability protection relating to all of our oil and gas operations (including environmental and pollution claims) with a total limit of coverage in the amount of $2,000,000 (with no deductible) and excess liability protection with a total limit of $3,000,000 (with a deductible of $10,000).

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. In addition, pollution and environmental risks generally are not fully insurable. A loss not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Employees

As of December 31, 2012, we had no employees. We engage the services of our Interim President and Chief Accounting Office on a consulting or contract basis. We engage additional part-time consultants on an as-needed basis. We also rely on the availability of internal staff of Red Mountain Resources, Inc. (“Red Mountain”), the majority holder of our common stock, to assist with our operations. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

Hydraulic Fracturing Policies and Procedures

We contract with third parties to conduct hydraulic fracturing as a means to maximize the productivity of our oil and natural gas wells in almost all of our wells. Hydraulic fracturing involves the injection of water, sand, gel and chemicals under pressure into formations to fracture the surrounding rock and stimulate production.

Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately 50% of the drilling and completion costs for our wells are associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completing our wells are treated and are built into and funded through our normal capital expenditures budget. A change to any federal and state laws and regulations governing hydraulic fracturing could impact these costs and adversely affect our business and financial results. See “Risk Factors — Federal and state legislative and regulatory initiatives as well as governmental reviews relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect our level of production.”

The protection of groundwater quality is important to us. Our policy and practice is to ensure our service providers follow all applicable guidelines and regulations in the areas where we have hydraulic fracturing operations. In addition, we send at least one engineer or an experienced consultant on our behalf to the well site to personally supervise each hydraulic fracture treatment.

We believe that the hydraulic fracturing operations on our properties are conducted in compliance with all state and federal regulations and in accordance with industry standard practices for groundwater protection. These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by applicable state regulatory agencies, and cementing the casing to create a permanent isolating barrier between the casing pipe and surrounding geological formations. The casing plus the cement are intended to prevent contact between the fracturing fluid and any aquifers during the hydraulic fracturing or other well operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval. Injection rates and pressures are monitored at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string.

The vast majority of hydraulic fracturing treatments are made up of water and sand or other kinds of man-made propping agents. Our service providers track and report chemical additives that are used in the fracturing operation as required by the applicable governmental agencies.

Hydraulic fracturing requires the use of a significant amount of water. All produced water, including fracture stimulation water, is disposed of in a way that does not impact surface waters. All produced water is disposed of in permitted and regulated disposal facilities.

Environmental Matters and Regulation

Our exploration, development and production operations are subject to various federal, state and local laws and regulations governing health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things: require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and natural gas drilling and production; restrict the way we handle or dispose of our wastes or of naturally occurring radioactive materials generated by our operations; cause us to incur significant capital expenditures to install pollution control or safety related equipment operating at our facilities; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; impose specific health and safety criteria addressing worker protection;

require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; impose obligations to reclaim and abandon well sites and pits and impose substantial liabilities on us for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

Additionally, the United States Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and their interpretations thereof, and any changes that result in more stringent and costly operational requirements or waste handling, disposal, cleanup and remediation requirements for the oil and natural gas industry could have a significant impact on our operating costs. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or new interpretations of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our financial condition and results of operations. We may be unable to pass on such increased compliance costs to our customers.

We have been notified by the Bureau of Land Management ("BLM") that environmental deficiencies exist on our Tom Tom Tomahawk field in Chaves and Roosevelt counties in New Mexico. We have submitted a plan to remediate such activities to the BLM and the plan has been accepted. Before work can commence, we have to perform certain procedures such as sampling the soil. For the year ended December 31, 2012, we recorded a non-cash charge of $2,100,000 which is management's best estimate of the costs to remediate the environmental deficiencies. This estimate could materially differ from actual expenditures. We cannot assure you that the passage of more stringent laws and regulations in the future will not have a further negative impact on our business, financial condition or results of operations.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business is subject and for which compliance may have a material adverse impact on our capital expenditures, financial condition or results of operations.

Comprehensive Environmental Response, Compensation and Liability Act

Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state statutes impose joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so–called potentially responsible parties ("PRPs"), include the current and past owners or operators of a site where the release occurred and anyone who transported or disposed or arranged for the transport or disposal of a hazardous substance found at the site. CERCLA also authorizes the Environmental Protection Agency (the "EPA") and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of our operations, we will generate, transport and dispose or arrange for the disposal of wastes that may fall within CERCLA's definition of hazardous substances. Comparable state statutes may not contain a similar exemption for petroleum. We may also be the owner or operator of sites on which hazardous substances have been released.

Solid and Hazardous Waste Handling

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of solid and hazardous waste. Although oil and natural gas waste generally is exempt from regulations as hazardous waste under RCRA, we will generate waste as a routine part of our operations that may be subject to RCRA and not all state and local laws contain a comparable exemption. Further, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non–hazardous waste or categorize some non–hazardous waste as hazardous in the future. Any such change could result in an increase in our costs to manage and dispose of waste, which could have a material adverse effect on our financial condition and results of operations.

It is also possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials, or NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contract with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Clean Water Act

The Clean Water Act and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, and fill materials into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of certain permits issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure (“SPCC”) requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the United States Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non–compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, we may be liable for penalties and costs of remediation.

The Oil Pollution Act of 1990 (“OPA 90”) and its regulations impose requirements on “responsible parties” related to the prevention of oil spills and liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” under the OPA 90 may include the owner or operator of an onshore facility. The OPA 90 subjects responsible parties to strict, joint and several financial liability for removal costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. It also imposes other requirements on responsible parties, such as the preparation of an oil spill contingency plan. Failure to comply with the OPA 90 may subject a responsible party to civil or criminal enforcement action. We may conduct operations on acreage located near, or that affects, navigable waters subject to the OPA 90. We believe that compliance with applicable requirements under the OPA 90 will not have a material and adverse effect on us.

Safe Drinking Water Act

The Safe Drinking Water Act (the “SDWA”) regulates, among other things, underground injection operations. Hydraulic fracturing continues to be under intense regulatory scrutiny both at the federal level and at the state level. In past legislative sessions, the United States Congress considered two companion bills that if passed would have imposed on our hydraulic fracturing operations significantly more stringent 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 our competition to copy our operations and 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, we could incur substantial compliance costs and the requirements could negatively impact our ability to conduct fracturing activities on our assets.

Many states have considered or adopted legislation or regulations requiring the disclosure of the chemicals used in hydraulic fracturing. Texas has adopted such a program, which is administered by the Railroad Commission of Texas. The Wyoming Oil and Gas Conservation Commission also passed a rule requiring disclosure of hydraulic fracturing fluid. In addition, a number of states in which we plan to conduct, are currently conducting, or may in the future conduct, hydraulic fracturing operations regulatory reviews hydraulic fracturing and new regulations from such reviews could restrict or limit our access to shale formations or could delay our operations or make them more costly.

The BLM has proposed a comprehensive rule regulating hydraulic fracturing on federal and certain tribal lands. The rules impose disclosure requirements on the use of hydraulic fracturing chemicals. These proposed rules also require

BLM approval prior to hydraulic fracturing. BLM also would require operators to meet other substantive requirements relating to well integrity and recordkeeping.

14

The EPA recently issued draft guidance under the SDWA, providing direction about how it will address the use of diesel in hydraulic fracturing activities. The draft guidance provides a definition of diesel fuels and discusses how the EPA's Underground Injection Control rules will be applied to hydraulic fracturing. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. Interim results of the study are expected in 2012, with final results expected in 2014. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This additional regulatory scrutiny could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Air Emissions

Our operations are subject to federal, state and local regulations for the control of emissions from sources of air pollution under the Clean Air Act ("CAA") and analogous state and local programs. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction and also impose various monitoring and reporting requirements. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous or toxic air pollutants may require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to forego construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA signed final rules under the CAA regarding emissions from oil and natural gas operations. The EPA rule subjects oil and natural gas operations to regulation under the New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAPS"), programs under the CAA, and imposes new and amended requirements under both programs. The new rules, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and natural gas operations, imposing requirements on those operations. The EPA also imposed NSPS standards for completions of hydraulically fractured natural gas wells, requiring the use of reduced emission completion techniques. The adopted rules allow in most circumstances, until January 1, 2015, facilities to combust natural gas that would escape during completion activities as an alternative to the reduced emission completion techniques. The NESHAPS proposal includes maximum achievable control technology standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. These new requirements may result in increased operating and compliance costs, increased regulatory burdens and delays in our operations. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Climate Change Legislation

In response to certain scientific studies suggesting that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") are contributing to the warming of the Earth's atmosphere and other climatic changes, the United States Congress has considered legislation to reduce such emissions. To date, the United States Congress has failed to enact a comprehensive GHG program. Some states, either individually or on a regional level, have considered or enacted legal measures to reduce GHG emissions. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, it is possible that smaller sources of emissions could become subject to GHG emission limitations. The cost of complying with these programs could be significant.

The EPA published finding that emissions of GHGs presented an endangerment to public health and the environment. These findings by the EPA allowed the agency to proceed through a rule-making process with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the CAA.

Consequently, the EPA adopted two sets of regulations that would require a reduction in emissions of GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources. On June 3, 2010, the EPA published its final rule to address permitting of GHG emissions from stationary sources under the prevention of significant deterioration (“PSD”) and Title V permitting programs. The final rule tailors the PSD and Title V permitting programs to apply to qualifying stationary sources of GHG emissions in a multi-step process, beginning January 2, 2011, with the largest sources first subject to permitting. In addition, the EPA has adopted a rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States. On November 8, 2010, the EPA finalized its regulations to expand its final rule on GHG emissions reporting to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis beginning in 2012 for emissions occurring in 2011. While we believe that we will be able to substantially comply with such reporting requirements without any material adverse effect to our financial condition, since such reporting requirements with respect to GHG emissions are new in the oil and natural gas industry, there can be no assurance that our reports will initially be in substantial compliance or that such requirements will not develop into more stringent and costly obligations that may have a significant impact on our operating costs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Any one of these climate change regulatory and legislative initiatives could have a material 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 GHGs 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 a material adverse effect on our business and results of operations.

OSHA and Other Laws and Regulations on Employee Health and Safety

To the extent not preempted by other applicable laws, we are subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state statutes, where applicable. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right–to–know regulations under the Title III of CERCLA and similar state statutes, where applicable, require us to organize and maintain information about hazardous materials used or, as applicable, produced in our operations and that this information be provided to employees, state and local government authorities and, where applicable, citizens. OSHA may enforce workplace safety regulations through issuance of citations for violations of its standards, which include, but are not limited to, those regarding hazard communication, personal protective equipment, general environmental controls, and materials handling and storage. We believe that we are in substantial compliance with these requirements where applicable and with other applicable OSHA and comparable requirements.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act ("NEPA") which requires federal agencies, including the U.S. Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Endangered Species Act

The Endangered Species Act, as amended (the "ESA"), and analogous state statutes restrict activities that may affect endangered and threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability.

Failure to comply with applicable laws and regulations can result in substantial penalties and possibly cessation of drilling and production operations. The regulatory burden on the industry increases the cost of doing business and affects profitability. We believe that we are in substantial compliance with existing requirements and such compliance will not have a material adverse effect on our financial condition, cash flows or results of operations. Nevertheless, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Drilling and Production

Our operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The states and some counties and municipalities in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled; and
- the plugging and abandonment of wells.

State laws, including Texas, regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction.

In addition, 11 states have enacted surface damage statutes ("SDAs"). These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners and users. Most also contain bonding requirements and specific expenses for exploration and producing activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

We do not control the availability of transportation and processing facilities used in the marketing of our production. For example, we may have to shut-in a productive natural gas well because of a lack of available natural gas gathering or transportation facilities.

If we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, the Bureau of Ocean Energy Management, Regulation and Enforcement or other appropriate federal or state agencies.

Transportation of Oil

Sales of oil are not currently regulated and are made at negotiated prices. Nevertheless, the United States Congress could reenact price controls in the future.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an annual increase or decrease in the cost of transporting oil to the purchaser, effective July 1 of each year. The FERC reviews the indexing methodology every five years. In its latest order on the methodology, issued in December 2010, the FERC concluded that an index level of the Producer Price Index for Finished Goods plus 2.65 percent should be established for the five-year period commencing July 1, 2011.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When shipper nominations exceed full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 (the "NGA"), the Natural Gas Policy Act of 1978 (the "NGPA"), and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, the United State Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission (the "CFTC"). See "—Other Federal Laws and Regulations Affecting Our Industry—Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to the FERC on May 1 of each year for the previous calendar year. Currently, Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. See "—Other Federal Laws and Regulations Affecting Our Industry—FERC Market Transparency Rules."

Gathering services, which occur upstream of jurisdictional transmission services, are regulated by the states. In addition, intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by the FERC. The basis for regulation of intrastate natural gas transportation and gathering the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline and gathering pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

State Natural Gas Regulation

Various states, including Texas, regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (the "EPAct 2005"). The EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by the FERC, and furthermore provides the FERC with additional civil penalty authority. The EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. On January 19, 2006, the FERC issued Order No. 670, a rule that implements the anti-manipulation provision of the EPAct 2005 and makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC: (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of the FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

FERC Market Transparency Rules

On April 19, 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting. In 2011, a federal appellate court determined that FERC does not have legal authority to impose reporting requirements on wholly-intrastate pipelines.

Additional proposals and proceedings that might affect the natural gas industry are pending before the United State Congress, the FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Item 1A. Risk Factors

Risks Related to Our Business

We may not have sufficient capital to operate our business as presently contemplated.

The oil and natural gas industry is capital intensive. We make and expect to continue to make significant capital expenditures in our business for the exploration, development, production and acquisition of oil and natural gas reserves. Improvement in commodity prices may result in an increase in our actual capital expenditures.

We plan to spend between $8 million and $12 million during fiscal 2013 to drill and complete wells, re-enter and complete wells, or improve infrastructure. Our main area of focus is the Tom Tom/Tomahawk Prospect, where we will begin work on the field alongside the execution of our remediation plan. For fiscal 2013, this included the re-entry of 14 gross wells (11.7 net), drilling of 6 gross wells (5.2 net), and the improvement of field infrastructure. We will also spend capital in several non-operated prospect areas. Currently, we are committed to participating in the drilling of 12 gross wells (1.1 net) in fiscal 2013. We expect to finance these activities with cashflow generated from operations and availability under our line of credit with Independent Bank.

Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold;
- our ability to acquire, locate and produce new reserves; and
- the ability of our banks to lend.

Debt financing could lead to:

- a substantial portion of operating cash flow being dedicated to the payment of principal and interest;
- us being more vulnerable to competitive pressures and economic downturns; and
- restrictions on our operations, including our ability to pay dividends.

If sufficient capital resources are not available, we might be forced to cease operations entirely, curtail developmental and exploratory drilling and other activities or be forced to sell some assets on an untimely or unfavorable basis, which would have a material adverse effect on our business, financial condition and results of operations.

Our outstanding debt contains covenants restricting certain actions we may take.

Our credit agreement with Independent Bank contains various restricting certain actions we may take, including, but not limited to, incurring additional indebtedness, entering into any merger, selling any of our assets, making certain investments and paying dividends. The credit agreement also contains various financial covenants requiring us to maintain a certain ratio of debt compared to EBITDAX (as defined in the credit agreement). These restrictions and covenants may adversely effect our operations.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

Growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

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

The price we receive for our oil and natural gas will heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the price and quantity of imports of foreign oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and other state-controlled oil companies relating to oil and natural gas price and production control;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals;
- the availability of refining capacity;

- price and availability of transportation and pipeline systems with adequate capacity;
- weather conditions and natural disasters;
- governmental regulations;

21

- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors’ supplies of oil and natural gas;
- energy conservation and environmental measures;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels and energy sources; and
- domestic and international drilling activity.

Declines in oil and natural gas prices may materially adversely affect our financial condition, liquidity, and ability to finance planned capital expenditures and results of operations and may reduce the amount of oil and natural gas that we can produce economically. This could have a material adverse effect on our liquidity and financial condition.

Properties that we acquire may not produce as projected, and we may be unable to accurately predict reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

We may acquire additional interests in oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards and liabilities, potential tax and Employee Retirement Income Security Act liabilities, and other liabilities and other similar factors. Generally, it is not feasible for us to review in detail every individual property involved in an acquisition, and our review efforts are normally focused on the higher-valued properties. Even a detailed review of properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not inspect every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable and may be limited by floors and caps on such indemnity. In addition, we may acquire oil and natural gas properties that contain commercially productive reserves which are less than predicted. Any of these factors could have a material adverse effect on our results of operations and reserve growth.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

We cannot control the development of the properties we do not operate, which may adversely affect our production, revenues and results of operations.

We do not operate the majority of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of our drilling and development activities on those properties depend upon a number of factors outside of our control, including:

- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of suitable technology.

As a result of any of the above or an operator's failure to act in ways that are in our best interest, our allocated production revenues and results of operations could be adversely affected.

Drilling for and producing oil and natural gas are speculative activities and involve numerous risks and substantial and uncertain costs that could adversely affect us.

Our future financial condition and results of operations will depend on the success of our acquisition, exploitation, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially productive oil or natural gas reserves. Our decisions to acquire, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as flooding;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems;

- limitations in the market for oil and natural gas; and
- costs and availability of drilling rigs, equipment, supplies, personnel and oilfield services.

Even if drilled, our completed wells may not produce reserves of oil or natural gas that are commercially productive or that meet our earlier estimates of economically recoverable reserves. A productive well may become uneconomic if water or other deleterious substances are encountered, which impair or prevent the production of oil and/or natural gas from the well. Our overall drilling success rate or our drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially harm our operations and financial condition by reducing our available cash and resources.

Reserve estimates depend on many assumptions that may turn out to be inaccurate.

Any material inaccuracies in our reserve estimates or underlying assumptions could materially affect the quantities and present values of our reserves. This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves and PV-10 and standardized measure of our proved oil and natural gas reserves. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves and amount of PV-10 and standardized measure that we may report. The process of preparing these estimates requires the projection of production rates and timing of development expenditures and analysis of available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities of reserves and amount of PV-10 and standardized measure that we may report. In addition, we may adjust estimates of proved reserves and amount of PV-10 and standardized measure to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Moreover, there can be no assurance that our reserves will ultimately be produced or that our proved undeveloped reserves will be developed within the periods anticipated. Any significant variance in the assumptions could materially affect the estimated quantity our reserves and amount of PV-10 and standardized measure.

Investors should not assume that the PV-10 of our proved reserves is the current market value of our estimated oil and natural gas reserves. PV-10 is based on prices and costs in effect on the date of the estimate. Actual future prices, costs, and the volume of produced reserves may differ materially from those used in the PV-10 estimate.

Approximately 33.9% of our total estimated proved reserves as of December 31, 2012 were classified as proved undeveloped and may not be ultimately developed or produced.

As of December 31, 2012, approximately 33.9% of our total estimated proved reserves were undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The future drilling of proved undeveloped reserves is highly dependent upon our ability to fund our capital expenditures, which we estimate will be approximately $8.0 million to $12.0 million for 2013. We cannot be sure that these estimated costs are accurate, and we may be unable to obtain sufficient capital. Further, our drilling efforts may be delayed or unsuccessful, and actual reserves may prove to be less than current reserve estimates, which could have a material adverse effect on our financial condition, future cash flows and results of operations.

If we are unable to find purchasers of our natural gas, it could harm our profitability.

There generally are only a limited number of natural gas transmission companies with existing pipelines in the vicinity of a natural gas well or wells. In the event that producing natural gas properties are not subject to purchase contracts or that any such contracts terminate and other parties do not purchase our natural gas production, there is no assurance that we will be able to enter into purchase contracts with any transmission companies or other purchasers of natural gas and there can be no assurance regarding the price which such purchasers would be willing to pay for such natural gas. There presently exists an oversupply of natural gas in the marketplace, the extent and duration of which is not known. Such oversupply may result in reductions of purchases by principal natural gas pipeline purchasers.