CRIMSON EXPLORATION INC.
Form 10-K
March 15, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 001-12108

CRIMSON EXPLORATION INC.
(Exact name of Registrant as specified in its charter)

| | |
|---|---|
| Delaware | 20-3037840 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 717 Texas Avenue, Suite 2900, Houston, Texas | 77002 |
| (Address of principal executive offices) | (Zip Code) |

(713) 236-7400
(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, $0.001 par value per share | NASDAQ Global Market |

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 o No x

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange 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 requirements for the past 90 days.
Yes x No o

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 x No o

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. 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 definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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 aggregate market value of the Registrant's common stock held by non-affiliates of the Registrant was $99,420,433 based on the closing sales price of $4.59 of the Registrant's common stock. For purposes of this computation, all executive officers, directors and 10% beneficial owners of the Registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates.

On March 1, 2013, there were 46,063,822 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2013 Annual Meeting, expected to be filed within 120 days of our fiscal year-end, are incorporated by reference into Part III of this Form 10-K.

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CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in or incorporated by reference into this Annual Report on Form 10-K or other filings with the SEC and our public releases, including, but not limited to, information regarding the status and progress of our operating activities, the plans and objectives of our management, assumptions regarding our future performance and plans, and any financial guidance provided therein may constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from crude oil and natural gas properties, and also include those statements accompanied by or that otherwise include the words “may,” “could,” “believes,” “expects,” “anticipates,” “intends,” “estimates,” “projects,” “target,” “goal,” “plans,” “objective,” “potential,” “should,” or similar expressions or variations on such expressions that co the uncertainty of future events or outcomes. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties (some of which are beyond our control) that could cause or contribute to such differences include, without limitation, those discussed in the section entitled “Risk Factors” included in this Annual Report on Form 10-K.

Any of these factors and other factors contained in this Annual Report on Form 10-K could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward-looking statements contained in this Annual Report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. All forward-looking statements speak only as of the respective dates thereof.

We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

# PART I

## ITEM 1. BUSINESS

### Company Overview

We are an independent energy company engaged in the exploitation, exploration, development and acquisition of crude oil and natural gas properties. We have historically focused our operations in the onshore U.S. Gulf Coast, Texas and Colorado regions, which are generally characterized by high rates of return in known, prolific producing trends. We have shifted our strategic focus to include longer reserve life resource plays in Southeast Texas (the Woodbine oil plays), South Texas (the Eagle Ford Shale oil play and crude oil play in the Buda formation). We believe these plays provide significant long-term growth potential from multiple formations. Additionally, we have producing properties in the Denver Julesburg Basin ("DJ Basin") in Weld and Adams counties in Colorado, which we believe are prospective in the Niobrara Shale oil play. Until we see improvement in natural gas prices, we will focus our drilling activity predominantly on further developing our oil and liquids-rich assets.

We intend to grow reserves and production by developing our existing producing property base including, developing our oil/liquids resource potential in Southeast and South Texas, and by pursuing opportunistic acquisitions in areas where we have current operations and specific operating expertise. In 2012, we successfully transitioned from a predominantly natural gas weighted production profile to a current production profile of approximately 50 percent crude oil and natural gas liquids. We have developed a significant inventory of high quality drilling opportunities on our existing property base that should provide the opportunity for multiyear reserve growth. In 2013, we will continue to focus on our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous rig program planned for 2013. We also currently plan to drill one or more test wells in the crude oil play in the Buda formation in Zavala/Dimmit counties in South Texas. We will continue to monitor increasing industry activity in the James Lime play in East Texas and the oil weighted Niobrara Shale in the DJ Basin of Colorado to determine the future potential and strategy for optimizing value in each play prior to expending drilling capital. The results of drilling activity near our acreage will influence our strategy and activity level in these plays; and given success by nearby operators, we may adjust our capital budget to capitalize on opportunities on our acreage positions in these plays.

As of December 31, 2012, our proved reserves, as estimated by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum engineering firm, in accordance with reserve reporting guidelines mandated by the Securities and Exchange Commission ("SEC"), were 117.0 Bcfe, consisting of 61.9 Bcf of natural gas and 9.2 MMBbl of crude oil, condensate and natural gas liquids, with a PV-10 of $340.1 million, and a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $296.4 million. As of December 31, 2012, 53% of our proved reserves were natural gas, 54% were proved developed and 90% were attributed to wells and properties operated by us. Year-end PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure to PV-10 is provided under "Item 2. Properties - Proved Reserves".

The following summary table sets forth certain information with respect to our proved reserves as of December 31, 2012, as estimated by NSAI, and net average daily production and net acreage for the twelve months ended December 31, 2012:

| Region | Estimated Proved Reserves (MMcfe) | % Crude Oil | % Natural Gas | % Natural Gas Liquids | % Proved Developed | Average Daily Production (Mcfe/d) | Net acreage |
|---|---|---|---|---|---|---|---|
| | 50,908 | 45% | 39% | 16% | 51% | 18,909 | 26,569 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Southeast Texas | | | | | | | |
| South Texas | 55,809 | 21% | 64% | 15% | 57% | 15,337 | 50,972 |
| East Texas | 3,964 | 12% | 70% | 18% | 52% | 3,348 | 4,793 |
| Colorado and Other | 6,368 | 30% | 56% | 14% | 56% | 1,001 | 12,290 |
| Total | 117,049 | 32% | 53% | 15% | 54% | 38,595 | 94,624 |

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Areas of geographic focus as of December 31, 2012 are shown on the map below:

Our areas of primary focus consist of:

- Southeast Texas. At December 31, 2012, our Southeast Texas region included approximately 44,000 gross (26,600 net) acres, proven reserves of 50.9 Bcfe, and 72 gross (38.3 net) producing wells. We have actively developed this area since 2008, primarily focusing on the Yegua and Cook Mountain sands in Liberty County until 2012. In 2012, we shifted our focus to the horizontal development of the Woodbine oil potential in Madison and Grimes counties, where there has recently been significant industry activity pursuing the Woodbine and Eagle Ford Shale oil plays near our leasehold positions. We will continue our focus on further developing our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous rig program planned for 2013. We currently have approximately 18,900 net acres and an inventory of approximately 498 potential drilling locations in Madison and Grimes counties, which includes our Woodbine, Eagle Ford Shale and Georgetown formations acreage. Drilling locations are based on 160 acre well spacing.

- South Texas. At December 31, 2012, our South Texas region included approximately 97,800 gross (51,000 net) acres, proven reserves of 55.8 Bcfe, and 272 gross (145.7 net) producing wells. Approximately 18,500 gross (8,600 net) acres are targeting the Eagle Ford Shale liquids play, over 90% of which is held by production. We began development of the Eagle Ford Shale in Bee County in 2010 and in Karnes and Zavala/Dimmit counties in 2011. In 2012, we successfully drilled 5 gross (3.4 net) producing wells targeting the Eagle Ford Shale. We currently plan to drill one or more test wells in the crude oil play in the Buda formation in Zavala/Dimmit counties in South Texas in 2013. Our estimated net proven Eagle Ford Shale reserves in this area of 13.6 Bcfe were comprised of 76% liquids with 14 gross (7.5 net) producing wells as of December 31, 2012.

The remaining 79,300 gross (42,400 net) acres in South Texas are located in our conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved conventional reserves in this area of 42.3 Bcfe were comprised of 77% gas with 258 gross (138.2 net) producing wells as of December 31, 2012.

- East Texas. At December 31, 2012, our East Texas region included approximately 7,500 gross (4,800 net) acres, proven reserves of 4.0 Bcfe comprised of 70% gas, and 8 gross (4.0 net) producing wells. Reflected as a negative revision to proved reserves in the December 31, 2012 reserve report were 91.7 Bcfe of reserves we still own but that were revised downward from proven reserves due to the low natural gas price environment. We actively developed the Haynesville and Mid-Bossier Shales in this area in 2009 through

2011 during a more favorable natural gas price environment. We will continue to monitor the drilling success by larger industry players as well as a midstream solution for processing liquids-rich gas from the James Lime formation in this area. Approximately 85% of our acreage in East Texas was held by production with the majority of the remaining leases expiring in 2013. Other than the aforementioned test wells, we have no plans to drill in the area in 2013 due to a challenging natural gas price environment.

We also own interests in the following areas:

- Colorado and Other. This region includes approximately 19,900 gross (12,300 net) acres in the DJ Basin in Colorado (mostly in Adams and Weld counties), small non-operating working interests in the Fenton field area of Calcasieu Parish, Louisiana and a minor crude oil property in Mississippi. There has been increasing activity since 2011 in the area of our Colorado acreage in pursuit of the Niobrara Shale oil formation. Substantially all of our 10,000 net acres in the Niobrara Shale are held by production and we plan to monitor the 2013 industry activity and results of our peers in the Niobrara Shale to develop our strategy for maximizing the value of our position in the area.

We intend to continue to evaluate potential acquisition opportunities in our core areas, to expand our presence in our Southeast and South Texas resource plays, to exploit our oil and liquids-rich positions, and to continue to develop exploitation opportunities on our conventional properties where commodity price-justified. Acquisition efforts will typically be focused on areas in which we can leverage our geographic and geological expertise to exploit identified drilling opportunities, and where we can develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves.

Capital expenditures for 2012 were $79.3 million, of which $63.5 million was used to drill 12 gross (7.9 net) wells and to sidetrack one (0.6 net) well with a combined success rate of 100%. The remaining $15.8 million was used to build facilities, acquire and extend leases, and complete wells drilled in prior years. Our 2013 capital budget is currently forecasted to be approximately $58.7 million, exclusive of acquisitions, if any.

Offices

We currently lease and sublease, through January 31, 2019, corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Rent, including parking related to this office space for the twelve months ended December 31, 2012 was approximately $2.4 million. Effective January 1, 2013, we subleased of this space to a third party for a total rental of approximately $85,000 per month from January 1, 2013 through January 31, 2014.

Strategy

The key elements of our business strategy are:

- Enhance our portfolio by allocating capital to our oil and liquids-rich opportunities. Beginning in 2011, we allocated substantially all of our capital resources to developing oil and liquids-rich opportunities to transition from a natural gas weighted production profile to a balanced production profile between oil/liquids and natural gas. In 2012, we have successfully transitioned from a 70% natural gas production profile in 2011 to a current production profile of approximately 50 percent crude oil and natural gas liquids. We will continue to pursue a drilling program that is designed to develop our multiple oil and liquids rich opportunities in established, active areas. Due to the challenging natural gas price environment and superior economics from oil production, we allocated our entire 2012 capital budget to oil and liquids-weighted opportunities, and plan to continue this strategy through 2013. We currently plan to develop the oil and natural gas liquids resource potential that we believe exists, from numerous formations, on our Madison and Grimes counties’ acreage in Southeast Texas and our Zavala/Dimmit counties’ acreage in South Texas. If warranted by market conditions, success in these areas and capital availability, we may further accelerate our drilling program in one or both areas. We currently do not plan to further develop our acreage position in the East Texas Haynesville/Mid-Bossier natural gas plays until the outlook for natural gas prices improves significantly.

- Pursue the development of the Woodbine horizontal oil redevelopment play in Madison and Grimes counties in Southeast Texas. We have approximately 26,900 gross (18,900 net) acres in Madison and

Grimes counties from which we have historically focused primarily on maximizing existing production from conventional wells. During 2012, we completed 7 gross (4.5 net) wells on our acreage, targeting the Woodbine. We plan to have a rig active in Madison and Grimes counties for all of 2013. Based on those results, we believe that large portions of our acreage position in the area may be prospective for horizontal redevelopment of the Woodbine, Eagle Ford, Georgetown, Lewisville and other formations.

- Develop South Texas. In 2012, we drilled 4 gross (2.9 net) wells in our Karnes and Zavala County areas, targeting the Eagle Ford Shale oil window and one gross (0.5 net) well in the Eagle Ford Shale gas/condensate window in Dimmit County. We currently plan to drill one or more test wells in the crude oil play in the Buda formation in Zavala/Dimmit counties in 2013. If availability of capital resources and nearby success warrant it, we may also resume development of our Eagle Ford Shale play.

- East Texas resource play. We believe that the further exploitation of our significant unproven resource potential in the Haynesville Shale, Mid-Bossier and James Lime formations, existing on our approximate 7,500 gross (4,800 net) acreage position in East Texas will provide long-term natural gas reserve and production growth in the future. Our interests in this area included 91.7 Bcfe of proved reserves as of December 31, 2012 that were declassified as proved in 2012 after becoming uneconomical due to the low natural gas price environment. We do not anticipate devoting significant drilling capital to this gas-oriented area until we see an improvement in the natural gas price environment and outlook as well as development of a midstream solution for processing liquids-rich James Lime gas. As of December 31, 2012, we had 8 gross (4.0 net) producing gas wells in this area.

- Colorado Niobrara Shale. Our activities in Colorado have historically been limited to the production of small amounts of oil and gas from the DJ Basin in Weld and Adams counties. Recent industry activity in the area has proven that the application of horizontal drilling technology for oil in the shallower Niobrara Shale may provide attractive return possibilities. We believe that the Niobrara Shale is prospective on at least part of our acreage. We plan to limit our activity in 2013 to monitoring the increased activity by larger industry players in the Niobrara Shale. We will evaluate their results to develop a strategy for maximizing the value of our position.

- Exploit our existing producing conventional property base to generate cash flows. We believe our multi-year drilling inventory of exploitation opportunities on our existing conventional producing properties provides us with a solid, dependable platform for future reserve and production growth. We own 3D seismic data that covers substantially all of our Liberty County acreage in South Texas, giving us a higher degree of confidence in the potential in this area. Due to our focus on our resource plays, activity on our conventional asset base in 2012 was limited to production enhancing workover activity. As a result of our desire to more extensively develop our positions in the Woodbine and Eagle Ford Shale plays, we have not currently allocated any additional drilling capital to further develop this area in 2013. We do plan to continue to allocate limited capital resources to our existing property base for production enhancing workover activity in 2013

- Pursue accretive, opportunistic acquisitions that meet our strategic and financial objectives. We intend to continue evaluating opportunistic acquisitions of crude oil and natural gas properties, including both undeveloped and developed reserves, in areas where we currently have a presence and specific operating expertise.

- Reduce commodity price exposure through hedging. We utilize commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We use a series of swaps and costless collars to accomplish our commodity hedging strategy. As of March 2013, we have 7.9 Bcfe of equivalent production hedged between January 1, 2013 and December 31, 2014. For 2013 production we have 0.3 MBbl of crude oil hedges at an average Brent floor price of $107.44/Bbl, 0.2 MBbl of crude oil hedges at an average WTI floor price of $101.25/Bbl and 3.5 Bcf of natural gas hedges at an average floor price of $3.40/MMBtu. For 2014 production, we have 0.1 MBbl of crude oil hedges at an average Brent floor price of $102.10/Bbl and 1.0 Bcf of natural gas hedges at an average floor price of $3.63/MMBtu.

Our Employees

On March 1, 2013, we had 69 full time employees, of which 20 were field personnel. We have been able to attract and retain a talented team of industry professionals that have been successful in achieving significant growth and success in the past. As such, we are well-positioned to adequately manage and develop our existing assets and also to increase our proved reserves and production through exploitation of our existing asset base, as well as the continuing identification and development of new growth opportunities. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

Available Information

We file annual, quarterly and other reports and other information with the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). You may read and copy any reports, statements or other information filed by us at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's web site at http://www.sec.gov.

We make available free of charge on our internet website at www.crimsonexploration.com our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and any amendments to those reports, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Information contained on our website is not incorporated by reference into this Form 10-K and you should not consider such information as part of this report or other information regarding issuers that file electronically with the SEC.

Seasonal Nature of Business

The demand for oil and natural gas fluctuates depending on the time of year. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies, and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand.

Government Regulation and Industry Matters

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the SEC. These rules and regulations could make it more difficult for us to obtain certain types of insurance, including director and officer liability insurance, and we may be forced to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. The impact of these rules and regulations could also make it more difficult for us to attract and retain qualified persons to serve on our board of directors, our board committees or as executive officers.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the release of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; or require remedial measures to mitigate pollution from current or former operations. Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil, and criminal penalties. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed or reinterpreted, and any such changes or interpretations could have an adverse effect on our business.

Industry Regulations

The availability of a ready market for crude oil, natural gas and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of crude oil, natural gas, and natural gas liquids production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of crude oil, natural gas and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of crude oil, natural gas, and natural gas liquids, protect rights to produce crude oil, natural gas and natural gas liquids between owners in a common reservoir, control the amount of crude oil, natural gas and natural gas liquids produced by assigning allowable rates of production, and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted.

The following discussion summarizes the regulation of the U.S. oil and gas industry. We believe that we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although there can be no assurance that this is or will remain the case. Moreover, such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Crude oil, Natural gas and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in and the unitization or pooling of crude oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws which establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of crude oil, natural gas and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act of 1938 (the "NGA"), the Federal Energy Regulatory Commission (the "FERC") regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the “Decontrol Act”) deregulated natural gas prices for all “first sales” of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC’s jurisdiction over natural gas transportation.

Under the provisions of the Energy Policy Act of 2005 (the “2005 Act”), the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission (the "CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. To the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC's regulations or an interstate pipeline's tariff could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978 (the "NGPA"), the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required pipelines, among other things, to perform "open access" transportation of gas for others, "unbundle" their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC's other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, we cannot predict whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas. Again, we do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the "FTC") prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of up to $1 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of crude oil transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In March 2006, to implement the second of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPI plus 1.3 percent) should be the oil pricing index for the five-year period beginning July 1, 2006. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

Environmental and Occupational Health and Safety Matters

Our crude oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment, or otherwise relating to environmental protection. Numerous governmental authorities, including the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may require the acquisition of a permit to conduct drilling and other regulated activities, restrict the types, quantities and concentration of various substances that may be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from current or former operations; impose specific health and safety criteria addressing worker protection; and impose substantial liabilities for pollution resulting from production and drilling 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. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue in the future, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that results in more stringent and costly well drilling, construction, completion or water management activities, waste handling, storage, transport, disposal or remediation requirements, our business and prospects could be materially and adversely affected.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as ("CERCLA") or the "Superfund" law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These potentially responsible persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also generate wastes that are subject to the federal Resource Conservation and Recovery Act, as amended (the "RCRA"), and comparable state statutes. The RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of nonhazardous and hazardous wastes, and the EPA and various state agencies stringently enforce the approved methods of management and disposal of these wastes. While the RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of crude oil and natural gas from regulation as hazardous wastes, we can provide no assurance that this exemption will be preserved in the future. Repeal or modification of this exclusion or similar exemptions under state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the natural gas and oil industry in general. In any event, these excluded wastes are subject to regulation as nonhazardous wastes.

We currently own, lease or operate numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have used good operating and waste disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for recycling or disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. These properties and the petroleum hydrocarbons or wastes disposed thereon may be subject to the CERCLA, RCRA and analogous state laws as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, which may impose strict, joint and several liability, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The Clean Air Act, as amended (the "CAA"), and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of crude oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Based on findings made by the EPA in December 2009 that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay or ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, which include the majority of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has, from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products.  Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.  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 assets and operations.

The Federal Water Pollution Control Act, as amended (the "Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. Any such discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure plan 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 permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990, as amended (the "OPA"), amends the Clean Water Act and contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under the OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemical additives under pressure into targeted subsurface formations to stimulate production. We routinely use hydraulic fracturing techniques in many of our completion programs. Hydraulic fracturing typically is regulated by state oil and gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (the "SDWA") over hydraulic fracturing involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states, including Texas, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior have evaluated or, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SWDA or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our hydraulic fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party pollution claims in accordance with, and subject to the terms of such policies.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the federal Bureau of Land Management ("BLM"), are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the BLM, 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. Currently, we have minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects.

Environmental laws such as the Endangered Species Act, as amended ("ESA"), may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits taking of endangered species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. 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. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Title to Properties

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, and liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed independent third party attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our natural gas and crude oil properties to secure our senior secured revolving credit agreement and second lien credit agreement. These mortgages and the credit agreements contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 9 - “Debt" for further information.

Marketing

We sell a significant portion of our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to three years and crude oil production to purchasers under sales agreements with primary terms of up to one year. The sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments, while the sale prices for crude oil are tied to industry standard posted prices subject to negotiated price adjustments.

Our purchasers are engaged in the natural gas and crude oil business throughout the world. Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. For the years ended December 31, 2012, 2011 and 2010, our top ten purchasers collectively represented approximately 88%, 83% and 80% of total revenues, respectively. Our four largest purchasers in 2012 accounted for 31% (Sunoco, Inc.), 20% (Valero Marketing & Supply Co.), 14% (DCP Midstream, LP) and 10% (Shell Trading (U.S.) Company) of total revenues, respectively. This concentration of purchasers may increase our overall exposure to credit risk, and our purchasers will likely be similarly affected by changes in economic and industry conditions. Our financial condition and results of operations could be materially adversely affected if one or more of our significant purchasers fails to pay us or ceases to acquire our production on terms that are favorable to us or at all. However, we believe our current purchasers could be replaced by other purchasers under contracts with similar terms and conditions.

Competition

The oil and gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market natural gas and crude oil, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, and obtaining purchasers and transporters for the natural gas and crude oil we produce. There is also competition between producers of natural gas and crude oil 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 government of the United States; 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 natural gas and crude oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Insurance Matters

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. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Executive Officers

See Item 10. "Directors and Executive Officers of the Registrant," which information is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Crude oil, natural gas and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth.

Our revenue, cash flow from operations and future growth depend upon the prices and demand for crude oil, natural gas and natural gas liquids. The markets for these commodities are very volatile. Even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in crude oil, natural gas and natural gas liquids prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas remained low in 2012 when compared with average prices in prior years. In addition, periods of sustained lower prices may compel us to reduce our capital expenditures and budget for drilling. Prices for crude oil, natural gas and natural gas liquids may fluctuate widely in response to relatively minor changes in the supply of and demand for crude oil, natural gas and natural gas liquids and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of crude oil, natural gas and natural gas liquids;
- the price of foreign imports;
- worldwide economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- availability of pipeline infrastructure, treating, transportation and refining capacity;
- domestic and foreign governmental regulations and taxes; and
- the price and availability of alternative fuels.

Lower crude oil, natural gas and natural gas liquids prices may not only decrease our revenues on a per share basis, but also may reduce the amount of crude oil, natural gas and natural gas liquids that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. A reduction in our reserves could have other adverse consequences including a possible downward redetermination of the availability of borrowings under our senior secured revolving credit agreement, which would restrict our liquidity. Additionally, further or continued declines in prices could result in non-cash charges to earnings due to impairment write downs. Any such write-down could have a material adverse effect on our results of operations in the period taken.

Part of our strategy involves drilling in new or emerging plays; therefore, our drilling results in these areas are not certain.

The results of our drilling in new or emerging plays, such as in our East Texas and South Texas resource plays and the horizontal redevelopment of the Woodbine and other formations in Southeast Texas, are more uncertain than drilling results in areas that are more developed and with longer production history. Since new or emerging plays and new formations have limited production history, we are less able to use past drilling results in those areas to help predict our future drilling results. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. We may be unable to execute our expected drilling program in these areas because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services or otherwise, and/or crude oil, natural gas and natural gas liquids price declines. To the extent we are unable to execute our expected drilling program in these areas, our return on investment may not be as attractive as we anticipate and our common stock price may decrease. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

Initial production rates in shale plays tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Our future cash flows are subject to a number of variables, including the level of production from existing wells. Initial production rates in shale plays tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates. As a result, we generally must locate and develop or acquire new crude oil or natural gas reserves to offset declines in these initial production rates. If we are unable to do so, these declines in initial production rates may result in a decrease in our overall production and revenue over time.

Our development and exploration operations, including on our resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of undeveloped acreage and a decline in our crude oil, natural gas and natural gas liquids reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of crude oil, natural gas and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our senior secured revolving credit agreement. Our cash flow from operations and access to capital is subject to a number of variables, including:

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

If our revenues decrease as a result of lower crude oil, natural gas and natural gas liquids prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, to further develop and exploit our current properties, or to conduct exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our credit agreements contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base is redetermined resulting in a lower borrowing base under our senior secured revolving credit agreement, we may be unable to obtain financing otherwise available under our senior secured revolving credit agreement. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital resources.”

Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our crude oil, natural gas and natural gas liquids reserves.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

As of December 31, 2012, we had $244.1 million outstanding in principal amount, excluding a $4.7 million discount, of long-term debt. Our substantial level of indebtedness increases the possibility that we may be unable to pay, when due, the principal of, interest on, or other amounts due in respect of our indebtedness. Our substantial indebtedness, combined with our other financial obligations and contractual commitments, could have other important consequences, including the following:

- funds available for our operations and general corporate purposes or for capital expenditures will be reduced as a result of the dedication of a portion of our consolidated cash flow from operations to the payment of the principal and interest on our indebtedness;

- we may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;
- certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates;
- our degree of leverage could make us more vulnerable to downturns in general economic conditions;
- our ability to plan for, or react to, changes in our business and the industry in which we operate may be limited; and
- our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, investments, debt service requirements and other general corporate requirements may be reduced.

In addition, our senior secured revolving credit agreement and second lien credit agreement contain a number of significant covenants that place limitations on our activities and operations, including those relating to:

- creation of liens;
- hedging;
- mergers, acquisitions, asset sales or dispositions;
- payments of dividends;
- incurrence of additional indebtedness; and
- certain leases and investments outside of the ordinary course of business.

Our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could also result in a default under our credit agreements. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital resources” for further information regarding future compliance with these covenants.

In addition, our borrowing base on our senior secured revolving credit agreement could be reduced by our lenders and limit our availability of future borrowings, or require us to pay back current borrowings in excess of the new borrowing base. If we were required to pay back all or a portion of our debt, even if new financing were then available, it may not be on terms that are acceptable to us. See “—Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our crude oil, natural gas and natural gas liquids reserves.”

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 in the past 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 incentives currently available to oil and natural gas exploration and production companies. These proposed changes would 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 certain U.S. 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 these or any other similar changes in U.S. Federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our preferred stock or our common stock.

Slower economic recovery in the U.S. and other countries may materially adversely impact our operations results.

The U.S. and other economies are recovering from a global financial crisis and recession which began in 2008. Growth has resumed, but has been modest and at an unsteady rate. There are likely to be significant long-term effects resulting from the financial crisis and recession, including a future global economic growth rate that is slower than what was experienced in the years leading up to the crisis, and more volatility may occur before a sustainable, yet lower, growth rate is achieved.

Global economic growth drives demand for energy from all sources, including crude oil, natural gas and natural gas liquids. NYMEX settlement prices for natural gas and crude oil prices dropped dramatically in 2009 from record levels in July 2008. While prices of crude oil and natural gas liquids have improved, and we hedged natural gas and crude oil prices on a portion of our forecasted production from proved developed producing reserves for up to two years forward, a reduction in demand for, and the resulting lower prices of, crude oil, natural gas and natural gas liquids could adversely affect our financial condition and results of operations.

We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

We have incurred net losses in four of the last five fiscal years. We cannot assure you that our current level of operating results will continue or improve. Our activities could require additional debt or equity financing. Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of crude oil, natural gas and natural gas liquids, rates of production, timing of capital expenditures and drilling success. Negative changes in these variables could have a material adverse effect on our business, financial condition, results of operations and the market value of our common stock.

We may not be able to fully realize the value of our net operating loss carryforwards for Federal income tax purposes.

As of December 31, 2012, we had federal net operating loss (“NOL”) carryforwards of approximately $110.7 million, which are available to reduce our future federal taxable income and related income tax liability. Our federal NOL carryforwards of $110.7 million have a valuation allowance of $38.0 million reducing the amount to $72.7 million. Based upon the level of historical taxable income and our projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of the majority of these NOL carryforwards to reduce future Federal net income tax obligations. Future net losses could affect our ability to realize during the appropriate carryforward periods our available net operating loss carryforwards for Federal income tax purposes and the value of the related deferred tax asset. Our ability to use our available net operating loss carryforwards could be limited if we do not generate sufficient taxable income in future periods and the amount of the related deferred tax asset ultimately realizable could be further reduced in the future if our estimates of future taxable income during the carryforward periods are reduced.

We currently expect we will not be able to utilize NOL carryforwards of approximately $8.8 million, or $3.1 million tax adjusted, due to prior occurrences of an “ownership change”, as determined under Section 382 of the Internal Revenue Code, as amended, and have included this amount in our total valuation allowance of $38.0 million. If we were to experience a further “ownership change,” as determined under Section 382, our ability to offset taxable income arising after the ownership change with NOL carryforwards arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOL carryforwards we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the highest long-term tax-exempt rate during the three months prior to the date of the ownership change. The long-term tax-exempt rate is a rate published each month by the Internal Revenue Service. The application of this limitation could prevent full utilization of our pre-change NOL carryforwards arising prior to their expiration. It is possible that additional issuances of our common stock within the next few years, or the sale of our common stock by our larger shareholders, could cause us to experience another ownership change, in which case any NOLs existing at the time of the change would be limited in the manner described above.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions or data could materially reduce the estimated quantities and present value of our reserves.

The process of estimating crude oil, natural gas and natural gas liquids reserves is complex. It requires interpretations of available technical data and many estimates, including estimates based upon assumptions relating to economic factors. Any significant inaccuracies in these interpretations or estimates could materially reduce the estimated quantities and present value of reserves shown in this Annual Report. See "Item 1. Business" for information about our crude oil, natural gas and natural gas liquids reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as crude oil, natural gas and natural gas liquids prices, drilling and operating expenses, the amount and timing of capital expenditures, taxes and the availability of funds.

Actual future production, crude oil, natural gas and natural gas liquids prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil, natural gas and natural gas liquids reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report. A decrease in commodity prices can result in significant downward reserve revisions as some reserves are no longer economically producible. Other reserves may reduce PV-10 reserve value despite positive current cash flows, because discounted cash flows might be less than the 10% discount utilized in such measures. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil, natural gas and natural gas liquids prices and other factors, many of which are beyond our control.

Approximately 46% of our total estimated proved reserves at December 31, 2012 were proved undeveloped reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our crude oil, natural gas and natural gas liquids reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated.

The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated crude oil, natural gas and natural gas liquids reserves.

You should not assume that the present value of future net revenues from our proved reserves referred to in this Annual Report is the current market value of our estimated crude oil, natural gas and natural gas liquids reserves. In accordance with the requirements of the SEC, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2012 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2012. For crude oil and natural gas liquids volumes, the average West Texas Intermediate posted price was $91.21 per barrel. For natural gas volumes, the average Henry Hub spot price was $2.76 per MMBtu. The following sensitivity analyses for crude oil and natural gas do not include the volatility reducing effects of our derivative hedging instruments in place at December 31, 2012. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of December 31, 2012 would have decreased from $340.1 million to $335.4 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV-10 as of December 31, 2012, would have decreased from $340.1 million to $336.4 million. Any adjustments to the estimates of proved reserves or decreases in the price of crude oil or natural gas may decrease the value of our common stock. A reconciliation of our Standardized Measure to PV-10 is provided under "Item 2. Properties — Proved Reserves".

Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of crude oil, natural gas and natural gas liquids. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. For example, we have over 4,200 square miles of 3D data in the South Texas and Gulf Coast regions. However, even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

Drilling for and producing crude oil, natural gas and natural gas liquids are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for crude oil, natural gas and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- explosions and blowouts;
- pipe or cement failures;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages of skilled personnel;
- shortages or delivery delays of equipment and services or of water used in hydraulic fracturing activities;
- compliance with environmental and other regulatory requirements;
- natural disasters; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume operations; and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We carry limited environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Our acquisition strategy may subject us to greater risks.

The successful acquisition of properties requires an assessment of recoverable reserves, future crude oil, natural gas and natural gas liquids prices, operating costs, potential environmental and other liabilities, and other factors beyond our control. Such assessments are necessarily inexact and their accuracy uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, costs and liabilities, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to assess their capabilities or deficiencies fully. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

We may be unable to successfully integrate the properties and assets we acquire with our existing operations.

Integration of the properties and assets we acquire may be a complex, time consuming and costly process. Failure to timely and successfully integrate these assets and properties with our operations may have a material adverse effect on our business, financial condition and result of operations. The difficulties of integrating these assets and properties present numerous risks, including:

- acquisitions may prove unprofitable and fail to generate anticipated cash flows;
- we may need to (i) recruit additional personnel and we cannot be certain that any of our recruiting efforts will succeed and (ii) expand corporate infrastructure to facilitate the integration of our operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses or distract our management; and
- our management's attention may be diverted from other business concerns.

We are also exposed to risks that are commonly associated with acquisitions of this type, such as unanticipated liabilities and costs, some of which may be material. As a result, the anticipated benefits of acquiring assets and properties may not be fully realized, if at all.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing crude oil, natural gas and natural gas liquids properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing crude oil, natural gas and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

We may incur substantial impairment of proved properties.

If management's estimates of the recoverable proved reserves on a property are revised downward or if oil and/or natural gas prices decline, we may be required to record additional non-cash impairment write-downs in the future, which would result in a negative impact to our financial results. Furthermore, any sustained decline in oil and/or natural gas prices may require us to make further impairments. We review our proved oil and gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and natural gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value. For the years ended December 31, 2012, 2011 and 2010, we recorded impairments related to proved oil and gas properties of $114.4 million, zero and $0.5 million, respectively.

Management's assumptions used in calculating oil and gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as management's views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate a portion of the properties in which we own an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these properties. The failure of an operator of our wells to adequately perform oper