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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2009
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 000-21644

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: None

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.001 par value per share

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if smaller reporting company) 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 ☐ No ☒

As of June 30, 2009, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $12,936,996 based on the closing sales price of $4.00 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 9, 2010, there were 38,515,302 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2010 Annual Meeting, expected to be filed within 120 days of our fiscal year end, are incorporated by reference into Part III.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We make forward-looking statements throughout this Annual Report within the meaning of Section 27A of the Securities Act, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (*the "Exchange Act"*).

These forward-looking statements include, but are not limited to, statements regarding:

- estimates of proved reserve quantities and net present values of those reserves;
- reserve potential;
- business strategy;
- estimates of future commodity prices;
- amounts, timing and types of capital expenditures and operating expenses;
- expansion and growth of our business and operations;
- expansion and development trends of the oil and gas industry;
- acquisitions of natural gas and crude oil properties;
- production of crude oil and natural gas reserves;
- exploration prospects;
- wells to be drilled and drilling results;
- operating results and working capital; and
- future methods and types of financing.

Whenever you read a statement that is not simply a statement of historical fact (such as when we describe what we "believe," "expect" or "anticipate" will occur, and other similar statements), you must remember that our expectations may not be correct, even though we believe they are reasonable. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. We do not guarantee that the transactions and events described in this Annual Report will happen as described (or that they will happen at all). The forward-looking information contained in this Annual Report is generally located in the material provided under the headings "Business," "Risk Factors," and "Management's Discussion and Analysis of Financial Condition and Results of Operations" but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results and trends. For a discussion of risk factors affecting our business, see "Risk Factors."

PART I

ITEM 1. Business

Company Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of 824 gross drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91%.

As of December 31, 2009, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 97.5 Bcfe, net of 7.6 Bcfe of reserves sold in December 2009, consisting of 69.9 Bcf of natural gas and 4.6 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2009, 72% of our proved reserves were natural gas, 70% were proved developed and 86% were attributed to wells and properties operated by us. During the last three years, we have grown proved reserves from 46.4 Bcfe to 97.5 Bcfe. In addition, our average daily production increased from 7.3 MMcfe/d for the twelve months ended December 31, 2006 to 40.9 MMcfe/d for the twelve months ended December 31, 2009.

Our areas of primary focus include the following:

- *East Texas.* Our East Texas region includes approximately 17,300 gross (12,000 net) acres acquired in 2008 and 2009 in the highly prospective and active resource play in San Augustine and Sabine Counties, where we will focus primarily on the pursuit of the Haynesville Shale, Mid-Bossier Shale and James Lime formations. In October 2009, we participated in our first well in this area, a 52% working interest in the Devon Energy-operated Kardell #1H, a successful well in the Haynesville shale. While drilling this well, we also identified additional prospective formations, including the Pettet and Knowles Lime. During 2010, we intend to drill 7 gross (3.1 net) horizontal wells in this region.

- *Southeast Texas.* Our Southeast Texas region includes approximately 27,100 gross (15,100 net) acres in the Felicia field area in Liberty County, and in Madison and Grimes Counties. As of December 31, 2009, we owned and operated 26 gross (20 net) producing wells, representing approximately 39% of our average daily production for the twelve months of 2009. Our interests in non-operated producing wells in this area also contributed an additional 7% of our average daily production for the twelve months of 2009. During 2010, we plan to drill 4 gross (2.4 net) wells in this region in Liberty County.

- *South Texas.* Our South Texas region includes approximately 2,800 gross (1,200 net) acres in Bee County, which we believe to be prospective in the Austin Chalk and Eagle Ford Shale. Our conventional operations in this area include approximately 87,400 gross (51,600 net) acres predominantly in Brooks, Lavaca, DeWitt, Zapata, Webb and Matagorda Counties. As of December 31, 2009, we owned and operated 88 gross (69 net) producing wells, representing approximately 27% of our average daily production for the twelve months of 2009. Our interests in non-operated producing wells in the area also contributed an additional 15% of our average daily production for the twelve months of 2009. During 2010, we intend to drill 1 gross (0.4 net) horizontal well in this region to test the Eagle Ford shale.

We also own interests in the following areas:

- *Colorado and Other.* This region includes primarily producing assets and approximately 16,900 gross (11,900 net) acres in the Denver Julesburg Basin in Colorado (mostly in Adams County) and a minor crude oil property in Mississippi.

- *Southwest Louisiana.* Our Southwest Louisiana region, after the sale of substantially all of our operated and certain non-operated properties in the region in December 2009, includes approximately 3,700 gross (760 net) acres, primarily in the Fenton field area of Calcasieu Parish. In addition, we own a 15% working interest ownership in the 2007 exploratory well at West Cameron 432.

The following table sets forth certain information with respect to our estimated proved reserves as of December 31, 2009, as estimated by Netherland, Sewell & Associates, Inc., and net production and net acreage for the twelve months ended December 31, 2009. The following table also identifies potential drilling locations as of December 31, 2009:

Region	Estimated Proved Reserves as of December 31, 2009 (MMcfe)	% Natural Gas	% Proved Developed	Average Daily Production for the Twelve Months Ended December 31, 2009 (Mcfe/d)	Net acreage at December 31, 2009	Identified Potential Gross Drilling Locations at December 31, 2009(1)
Southeast Texas	27,108	55.6%	84.9%	15,927	15,111	26
South Texas	49,186	79.0%	57.2%	11,018	52,755	125
East Texas(2)	1,596	100.0%	100.0%	836	11,944	422
Colorado and Other	5,221	66.2%	45.2%	556	11,877	181
Southwest Louisiana(3)	—	—	—	2,857	759	—
Non-operated(3)(4)	14,378	75.6%	93.8%	9,714	—	70
Total	97,489	71.7%	70.3%	40,908	92,446	824

(1) Includes multiple drilling locations on acreage with multiple target formations.
(2) We recently completed our first well on our East Texas acreage, the Kardell #1H, as a horizontal Haynesville Shale producer, in which we own a 52% working interest. Drilling locations in this region were calculated assuming multiple independent potential formations and 120 acre spacing per potential horizontal East Texas location.
(3) On December 28, 2009, we closed on the sale of substantially all of our operated and certain non-operated Southwest Louisiana properties. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Southwest Louisiana Disposition."
(4) Our non-operated properties consist primarily of our 25% working interest in the Samano field in Starr and Hidalgo Counties in South Texas, our 28% working interest in certain fields in Liberty County in Southeast Texas and our 15% working interest in West Cameron 432.

We have significantly increased our proved reserves and production through acquisitions and drilling since our recapitalization in early 2005. In 2007, we tripled our reserve size through the acquisition from EXCO Resources, Inc. (*"EXCO"*) of producing properties in the South Texas, Southeast Texas and Southwest Louisiana regions, adding an aggregate of approximately 95 Bcfe to our net proved reserves at a cost of $2.50 per Mcfe of proved reserves as of the effective date. We added 21 Bcfe to our South Texas proved reserves through the Smith Production Inc. (*"Smith"*) acquisition in 2008 at an average cost of $2.82 per Mcfe of proved reserves as of the closing date. Our acquisitions are focused on areas in which we can leverage our geographic and geological expertise to exploit those drilling opportunities identified at the time of the acquisition and develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves. We intend to continue to pursue the acquisition of assets in our core areas, to continue to selectively expand our presence and exploit our positions in our East Texas and South Texas resource plays and to continue to develop exploratory opportunities through our internal prospect generation team.

During the latter half of 2008 and the full year 2009, we acquired approximately 12,000 net acres in San Augustine and Sabine Counties in East Texas, which we believe to be prospective in the Haynesville Shale, Mid-Bossier, and James Lime formations. We have identified 422 drilling locations on our acreage targeting these formations alone. Recent activity in the area indicates that the Pettet and Knowles Lime formations also appear prospective. We have separated our acreage into several joint development areas (*"JDAs"*) of varying sizes and are working with other industry players holding acreage positions in those areas to jointly develop our positions. Our "Bruin" prospect, on which our first well, the Kardell #1H was drilled, is one such JDA. We and Devon Energy Corporation, the operator, each contributed approximately 330 acres to the JDA in San Augustine County and drilled the Kardell #1H well. Given the success we have had on the Kardell #1H well, we will allocate a large portion of our drilling capital budget to develop this resource play further for the next several years.

Offices

We currently lease and sublease, through January 31, 2014, 54,939 square feet of executive and 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, 2009 was approximately $2.2 million. Effective January 1, 2010, we have subleased to a subtenant for approximately one year, 27,144 square feet of this space for a total rental of approximately $1.0 million.

Strategy

The key elements of our business strategy are:

- *Develop our East Texas resource play.* We have approximately 12,000 net acres in San Augustine and Sabine Counties of East Texas, which we believe is prospective in the Haynesville Shale, Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations. We commenced our first well (the Kardell #1H, 52% working interest) in this play in late June 2009 and completed that well in October 2009. We believe the Kardell #1H confirms the potential of our Bruin Prospect, which is comprised of approximately 3,000 net acres in San Augustine County, resulting in over 100 potential drilling locations in multiple formations. We are currently in the planning stages for several wells in this area and intend to further evaluate and exploit these multiple formations in 2010. We have an additional 8,944 net acres within Sabine and San Augustine Counties, and we expect to drill our initial well on that acreage in early 2010. We intend to allocate a substantial portion of our capital budget over the next several years to develop the significant potential that we believe exists on our East Texas acreage. We currently have budgeted for 2010 7 gross (3.1 net) wells that will target the Haynesville and Mid-Bossier Shales, while retaining future development opportunities in shallower formations.

- *Develop our South Texas resource play.* We have approximately 2,800 gross (1,200 net) acres in Bee County, Texas which we believe is prospective in the Austin Chalk and Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009. It was completed as a vertical well in the first quarter of 2010. The well flowed 600 Mcf per day at 2,400 psi flowing tubing pressure on an 8/64" choke after a small fracture stimulation. The well is currently shut-in due to limited production facilities. Crimson is encouraged by the results from the Dubose #1 and the potential of a future Eagle Ford horizontal well, which we currently have planned for the second half of 2010.

- *Exploit our existing producing property base to generate cash flows.* We believe our multi-year drilling inventory of high return exploitation opportunities on our existing conventional producing properties provides us with a solid platform to continue growing our reserves and production for the next several years. We believe these projects, if successful, will allow us to fund a larger portion of our resource plays and exploration activities from cash flows from operations. In 2010, we intend to focus much of our exploitation drilling on our Liberty County acreage, located in Southeast Texas. We will be targeting the Yegua and Cook Mountain formations in which we experienced an 82% success rate on 11 wells drilled in 2008 and in which industry participants have recently experienced success on wells in the area. We own 3D seismic that covers substantially all of our Liberty County acreage, giving us a higher degree of confidence in the potential in this area. During 2010, we intend to drill 4 gross (2.4 net) wells in this area.

- *Explore in defined producing trends.* Our exploration activities consist primarily of step-out drilling in known, producing formations in our legacy areas of South and Southeast Texas. In 2007, we began acquiring seismic data to use in identifying new exploration prospects. Currently, we have a library of over 4,200 square miles of 3D seismic data and over 2,500 linear miles of 2D seismic data.

- *Make opportunistic acquisitions that meet our strategic and financial objectives.* We may continue to seek to acquire natural gas and crude oil properties, including both undeveloped and developed reserves in areas where we have specific operating expertise.

- *Reduce commodity exposure through hedging.* We employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. As of December 31, 2009, we had 11.6 Bcfe of equivalent production hedged, representing 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 250 MBbl and 124 MBbl of crude oil hedges in place for 2010 and 2011, respectively. The average floor prices of our natural gas and crude oil hedges in place are $7.71/MMBtu and $83.02/Bbl in 2010 and $7.32/MMBtu and $66.50/Bbl in 2011.

Our Employees

On March 9, 2010, we had 74 full time employees, of which 20 were field personnel. We have been able to attract a very talented team of industry professionals from our industry peers 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 and exploration drilling. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

Government Regulation and Industry Matters

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the Securities and Exchange Commission (*"SEC"*). Recently enacted and proposed changes in the laws and regulations affecting public companies, including the provisions of the Sarbanes-Oxley Act of 2002 and rules adopted by the SEC, have resulted in increased costs to us. The new rules 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 events 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 natural gas, crude oil and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of natural gas, crude oil 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 natural gas, crude oil 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 natural gas, crude oil and natural gas liquids, protect rights to produce natural gas, crude oil and natural gas liquids between owners in a common reservoir, control the amount of natural gas, crude oil 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 United States 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 Natural Gas, Crude Oil 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 natural gas, crude oil 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, or NGA, of 1938, the Federal Energy Regulatory Commission, or 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, or 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, or 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, or 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, or 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, or 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 Regulations

Various federal, state and local authorities regulate our operations with regard to air and water quality, release of substances and other environmental matters. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can 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, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. In addition, various laws and regulations require that well, pipeline, and facility sites be abandoned and reclaimed. 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, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

We generate wastes that may be subject to the federal Resource Conservation and Recovery Act, as amended, or the RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or the EPA, and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease 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, prior owners and operators of these properties may not have used similar practices, and 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 hydrocarbons or wastes was not under our control. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, as amended, or 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 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.

Our operations may be subject to the Clean Air Act, as amended, or the CAA, and comparable state and local requirements. Amendments to the CAA adopted in 1990 contain provisions that have resulted in the gradual imposition of pollution control requirements with respect to air emissions from our operations. The EPA and states developed and continue to develop regulations to implement these requirements. We may be required to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill, which would establish an economy-wide cap-and-trade program to reduce "greenhouse gas" emissions, including carbon dioxide and methane by 17 percent from 2005 levels by the year 2020 and 80 percent by the year 2050. The U.S. Senate is considering a number of comparable measures. One such measure, the Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been reported out of the Senate Committee on Energy and Natural Resources, but has not yet been considered by the full Senate and also includes a cap-and-trade system for controlling greenhouse gas emissions in the United States. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of these bills remains uncertain, and such bills would have to undergo reconciliation before being adopted as law. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce. In addition, at least 20 states have already taken legal measures to control emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. In California, for example, the California Global Warming Solutions Act of 2006 requires the California Air Resources Board to adopt regulations by 2012 that will achieve an overall reduction in greenhouse gas emissions from all sources in California of 25% by 2020.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of crude oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated producers of natural gas, crude oil and natural gas liquids, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the crude oil and natural gas we produce.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate carbon dioxide, or CO_2, emissions from automobiles as “air pollutants” under the CAA. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate “air pollutants” from those and other facilities. On April 17, 2009, the EPA released a “Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA’s proposed finding concludes that the atmospheric concentrations of several key greenhouse gases threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key greenhouse gases and hence to the threat of climate change. On September 15, 2009, the EPA proposed a rule in anticipation of finalizing its findings to reduce emissions of greenhouse gases from motor vehicles, which rule is expected to be adopted in March 2010. Additionally, while the EPA’s proposed findings do not specifically address stationary sources, those findings, if finalized, would be expected to support the establishment of future emission requirements by the EPA for stationary sources. On September 23, 2009, the EPA finalized a greenhouse gas reporting rule establishing a national greenhouse gas emissions collection and reporting program. The EPA rules will require covered entities to measure greenhouse gas emissions commencing in 2010 and submit reports commencing in 2011. On September 30, 2009, the EPA proposed new thresholds for greenhouse gas emissions that define when CAA permits under the New Source Review, or NSR, and Title V operating permits programs would be required. Under the Title V operating permits program, the EPA is proposing a major source emissions applicability threshold of 25,000 tons per year (tpy) of carbon dioxide CO_2e (carbon dioxide equivalency) for existing industrial facilities. Facilities with greenhouse gas emissions below this threshold would not be required to obtain an operating permit. Under the Prevention of Significant Deterioration, or PSD, portion of the NSR, the EPA is proposing a major stationary source threshold of 25,000 tpy CO_2e. This threshold level would be used to determine if a new facility or a major modification at an existing facility would trigger PSD permitting requirements. The EPA is also proposing a significance level between 10,000 and 25,000 tpy CO_2e. Existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit. The EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the greenhouse gas significance level. These proposals, along with new federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business and demand for the crude oil and natural gas we produce.

The U.S. Senate and House of Representatives are currently considering bills entitled, the “Fracturing Responsibility and Awareness of Chemicals Act,” or the FRAC Act, to amend the federal Safe Drinking Water Act, or the SDWA, to repeal an exemption from regulation for hydraulic fracturing. If enacted, the FRAC Act would amend the definition of “underground injection” in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Although the legislation is still being developed, we do not expect the FRAC Act to have a material effect on our business because we contract out all of our hydraulic fracturing work due to the specialized nature of the activity and the extensive capital investment required.

Federal regulations require certain owners or operators of facilities that store or otherwise handle crude oil to prepare and implement spill prevention, control, and countermeasure, or the SPCC, and response plans relating to the possible discharge of crude oil into surface waters. SPCC plans at our producing properties were developed and implemented in 1999. In December 2008, the EPA amended the SPCC rule. On November 5, 2009, the EPA signed a notice amending certain requirements of the SPCC regulations to address concerns from the regulatory community raised since the release of the December 2008 amendments. The new SPCC rule is expected to be effective January 14, 2010. Although the EPA has not yet issued a final notice containing the new rules, it is clear that there will be changes impacting oil production facilities. These changes should not have a material adverse effect on us. The Oil Pollution Act of 1990, as amended, or the OPA, contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Our operations are also subject to the federal Clean Water Act, as amended, or the CWA, and analogous state laws. In accordance with the CWA, the state of Louisiana has issued regulations prohibiting discharges of produced water in state coastal waters effective July 1, 1997. Like OPA, the CWA and analogous state laws relating to the control of water pollution provide varying civil and criminal penalties and liabilities for releases of petroleum or its derivatives into surface waters or into the ground.

CERCLA, also known as 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 also are subject to a variety of federal, state and local permitting and registration requirements relating to the protection of the environment. Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse effect on us.

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, 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 attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our crude oil and natural gas properties to secure our 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 10 — “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 two 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, 2009, 2008 and 2007, our top ten purchasers collectively represented approximately 72%, 71% and 73% of total revenues, respectively. Our three largest purchasers in 2009 accounted for 28%, 9% and 7% 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 crude oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in 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 crude oil and natural gas we produce. There is also competition between producers of crude oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the 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 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 9. "Directors and Executive Officers of the Registrant," which information is incorporated herein by reference.

ITEM 1A. Risk Factors

Risks Related to Our Business

Natural gas, crude oil 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 natural gas, crude oil 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 natural gas, crude oil and natural gas liquids prices have a significant impact on the value of our reserves and on our cash flow. In addition, periods of sustained lower prices may compel us to reduce our capital expenditures and budget for drilling. Prices for natural gas, crude oil and natural gas liquids may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, crude oil and natural gas liquids and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas, crude oil 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 natural gas, crude oil and natural gas liquids prices may not only decrease our revenues on a per share basis, but also may reduce the amount of natural gas, crude oil 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.

Our East Texas leases must be drilled before expiration, generally within three years, in order to hold the leases by production. In the highly competitive market for Haynesville Shale acreage, failure to drill sufficient wells timely to hold this acreage will result in a substantial renewal cost, or if renewal is not feasible, loss of lease investment and prospective drilling opportunities in the Haynesville Shale, as well as in the Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations.

Our East Texas leases have three year terms which require that an initial producing well be drilled prior to expiration date or the lease will terminate. Most of our leases in this area were signed in late 2008. Generally, once an initial well is drilled and completed as a producer, the lease is extended for the duration of production subject to payment of royalties and additional wells may be drilled on that lease. During 2010, we intend to devote approximately 68% of our capital expenditure budget to this region. The leases in this area are extremely fragmented and much of the leased acreage is not contiguous. In many cases, contiguous leases owned by us are not large enough to accommodate horizontal drilling to the Haynesville Shale, which usually involves a horizontal lateral of between 4,000 to 5,000 feet within lease lines. In other cases, leases may be from fractional interest land owners and may not comprise a sufficient aggregate percentage working interest to make such a well economical. As a result, in order to realize the drilling opportunities in the Haynesville Shale, Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations, we and other similarly situated major lease owners and operators in East Texas will need to cooperate and negotiate joint drilling operations to drill initial wells prior to lease expirations. These negotiations may include the right to act as operator for jointly owned wells. If we do not reach agreements with other major lease owners and operators to drill wells prior to lease expirations, or if we are unable to drill timely sufficient wells to hold our acreage, we will lose the drilling opportunities and investment in the expiring leases unless we can successfully negotiate to renew the leases. We may not be able to renew the expired leases, or if renewed, the cost of releasing could be substantial, particularly if development in this area proves successful.

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 resource play, are more uncertain than drilling results in areas that are more developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. To the extent we are 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 natural gas, crude oil and natural gas liquids price declines, 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.

The results of our planned drilling in our East Texas and South Texas resource plays, which are newly emerging plays with limited drilling and production history, are subject to more uncertainties than our drilling program in our more established areas of operation in the onshore South Texas and U.S. Gulf Coast regions and may not meet our expectations for reserves or production.

In October 2009, we completed drilling our first well in the Haynesville Shale in East Texas, for which we were not operator, and in late January 2010, we completed a vertical test well in Bee County, South Texas in the Eagle Ford Shale. The presence of the Haynesville Shale in the East Texas area where we own leases was determined after the activity in the north Louisiana portion of the Haynesville Shale play and, therefore is not yet as defined. Part of our drilling strategy to maximize recoveries from the Haynesville Shale involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our direct experience with horizontal drilling of these shale plays is limited. 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, the results of our future drilling in the emerging shale plays are more uncertain than drilling results in our more established areas of operation with established reserves and production history.

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

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

Our development and exploration operations, including on our East Texas 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 properties and a decline in our natural gas, crude oil 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 natural gas, crude oil and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our 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 natural gas, crude oil and natural gas liquids we are able to produce from existing wells;
- the prices at which natural gas, crude oil 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 natural gas, crude oil 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 or to further develop and exploit our current properties, or for 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 revolving credit agreement, we may be unable to obtain financing otherwise available under our 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 natural gas, crude oil and natural gas liquids reserves.

The impairment of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry specifically, with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparty. We have exposure to these financial institutions in the form of derivative transactions in connection with our hedges. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. In addition, if any lender under our credit agreement is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender’s commitment under our credit agreement.

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, 2009, we had outstanding debt of $191.0 million under our credit agreements. 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 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. Even if new financing were then available, it may not be on terms that are acceptable to us. See "—Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements" and "—Our development and exploration operations, including on our East Texas 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 properties and a decline in our natural gas, crude oil and natural gas liquids reserves."

Changes to current laws may affect our ability to take certain deductions.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could negatively affect our financial condition and results of operations.

Recent changes in the financial and credit markets may impact economic growth and natural gas, crude oil and natural gas liquids prices may continue to be adversely affected by general economic conditions.

Based on a number of economic indicators, global economic activity slowed substantially in recent years. A continued slowing of global economic growth or lack of significant improvement in the global economy (and, in particular, in the United States) will likely reduce demand for natural gas, crude oil and natural gas liquids, which in turn could likely result in lower prices for natural gas, crude oil and natural gas liquids. NYMEX settlement prices for natural gas and crude oil prices dropped dramatically from record levels of approximately $13 per MMbtu and $145 per barrel, respectively, in July 2008 to below $3 per MMbtu in August 2009 and below $34 per barrel in December 2008. While prices have improved from those low levels, a reduction in demand for, and the resulting lower prices of, natural gas, crude oil and natural gas liquids could adversely affect our results of operations.

Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements.

Recent market events and conditions, including unprecedented disruptions in the credit and financial markets and the deterioration of economic conditions in the U.S. and internationally have had a significant material adverse impact on a number of financial institutions and have limited access to capital and credit for many companies. These disruptions could, among other things, make it more difficult for us to obtain, or increase our cost of obtaining, capital and financing for our operations. Access to additional capital may not be available on terms acceptable to us or at all. Difficulties in obtaining capital and financing or increased costs for obtaining capital and financing for our operations would have an adverse effect on our ability to fund our working capital and other capital requirements.

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 three 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 natural gas, crude oil 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.

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

The process of estimating natural gas, crude oil 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 natural gas, crude oil 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 natural gas, crude oil 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, natural gas, crude oil and natural gas liquids prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, crude oil 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. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas, crude oil and natural gas liquids prices and other factors, many of which are beyond our control.

Approximately 30% of our total estimated proved reserves at December 31, 2009 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 natural gas, crude oil 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 natural gas, crude oil 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 natural gas, crude oil 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, 2009 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2009. For crude oil and natural gas liquids volumes, the average West Texas Intermediate posted price was $57.65 per barrel. For natural gas volumes, the average Henry Hub spot price was $3.87 per MMBtu. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of December 31, 2009 would have decreased from $176.4 million to $174.4 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV-10 as of December 31, 2009, would have decreased from $176.4 million to $172.4 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. PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure of Discounted Net Cash Flows 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 natural gas, crude oil 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 and including 1,130 square miles of 3D data in the Lobo trend in South Texas that our internal prospect generation team uses to develop drilling opportunities in these areas. 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 natural gas, crude oil 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 natural gas, crude oil 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, pipeline ruptures and discharges of toxic gases;
- 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;
- 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 natural gas, crude oil 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 natural gas, crude oil 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 natural gas, crude oil and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

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 significant 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 operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory natural gas, crude oil and natural gas liquids transportation arrangements may hinder our access to natural gas, crude oil and natural gas liquids markets or delay our production. The availability of a ready market for our natural gas, crude oil and natural gas liquids production depends on a number of factors, including the demand for and supply of natural gas, crude oil and natural gas liquids and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our natural gas, crude oil and natural gas liquids may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

Unless we replace our natural gas, crude oil and natural gas liquids reserves, our reserves and production will decline, which would adversely affect our cash flows, our ability to raise capital and the value of our common stock.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing natural gas, crude oil and natural gas liquids reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our common stock and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

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

When the prices of natural gas, crude oil and natural gas liquids increase, we typically encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operation and financial condition.

Our hedging activities could result in financial losses or reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas, crude oil and natural gas liquids, as well as interest rates, we currently, and may in the future, enter into derivative arrangements for a significant portion of our natural gas, crude oil and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. As of December 31, 2009, we had 11.6 Bcfe of equivalent production hedged representing 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 250 MBbl and 124 MBbl of crude oil hedges in place for 2010 and 2011, respectively. We typically use a combination of swaps and costless collars. The average floor price of our natural gas and crude oil hedges in place is $7.71/MMBtu and $83.02/Bbl in 2010 and $7.32/MMBtu and $66.50/Bbl in 2011. As of December 31, 2009, we had entered into interest rate swap agreements with a total notional amount of $200.0 million related to our indebtedness. Under our interest rate swap agreements, we receive interest at a floating rate equal to one-month LIBOR and pay interest at a fixed rate of 1.50% for $50.0 million and pay interest at 2.90% for $150.0 million.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of our interest rate swap agreements, we may fail to benefit when rates fall, to the extent we have agreed to pay interest at a fixed rate, or face a greater degree of exposure when rates increase, to the extent we have agreed to pay interest at a floating rate. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Competition in the oil and gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing natural gas, crude oil and natural gas liquids, and securing equipment and trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

We depend on our senior management team and other key personnel. Accordingly, the loss of any of these individuals could adversely affect our business, financial condition and the results of operations and future growth.

Our success is largely dependent on the skills, experience and efforts of our people. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial conditions and results of operations and future growth. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

We are subject to complex federal, state, local and other law and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For instance, we may be unable to obtain all necessary permits, approvals and certificates for proposed projects. Alternatively, we may have to incur substantial expenditures to obtain, maintain or renew authorizations to conduct existing projects. If a project is unable to function as planned due to changing requirements or public opposition, we may suffer expensive delays, extended periods of non-operation or significant loss of value in a project. All such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local regulations as interpreted and enforced by governmental agencies and other bodies vested with much authority relating to the exploration for, and the development, production, transportation and marketing of, natural gas, crude oil and natural gas liquids. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on us.

We are subject to complex existing and pending environmental laws and regulations that could give rise to substantial liabilities or otherwise adversely affect our cost, manner or feasibility of doing business.

Recent and future environmental laws and regulations, including additional federal, regional and state restrictions on greenhouse gas (*"GHG"*) emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil, natural gas and natural gas liquids we produce. The U.S. Environmental Protection Agency (*"EPA"*) has issued a notice of finding and determination that emission of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. To this end, EPA has recently issued a mandatory GHG reporting rule that will require operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. The rule will require covered entities to measure GHG emissions commencing in 2010 and submit reports commencing in 2011. In addition, EPA has proposed a stationary source GHG permitting rule that would establish "significance levels" for major GHGs that would trigger review and permitting requirements. Similarly, the House of Representatives has approved the "American Clean Energy and Security Act of 2009," or "ACESA," that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs, and the Senate is currently considering similar legislation. At the state level, more than one-third of the states, including California, have begun taking actions either individually or through multi-state regional initiatives to control and/or reduce emissions of GHGs. The State of California has adopted legislation that caps California's greenhouse gas emissions at 1990 levels by 2020, and the California Air Resources Board is currently developing mandatory reporting regulations and early action measures to reduce GHG emissions prior to January 1, 2012. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce. It is not possible, at this time, to estimate accurately how these regulations would impact our business.

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

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale formations. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills, which are currently pending in the Energy and Commerce Committee and the Environmental and Public Works Committee of the House of Representatives and Senate, respectively, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, this legislation, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Our operations expose us to potentially substantial costs and liabilities with respect to environmental, health and safety matters.

We may incur substantial costs and liabilities as a result of environmental, health and safety requirements applicable to our crude oil and natural gas operations and other activities. These costs and liabilities could arise under a wide range of federal, state and local environmental, health and safety laws and regulations that cover, among other things, emissions into the air and water, habitat and endangered species protection, the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground injection wells, and wetlands protection. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with environmental, health and safety laws or regulations may result in assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining or limiting our current or future operations. Compliance with these laws and regulations also increases the cost of our operations and may prevent or delay the commencement or continuance of a given operation.

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health, or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations. See “Item 1. Business—Environmental Regulations.”

If we are unable to successfully prevent or address material weaknesses in our internal control over financial reporting, or any other control deficiencies, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. For example, for the quarter ended March 31, 2007, our management concluded that our historical documentation of related tax positions could have resulted in a material misstatement to our annual or interim financial statements and, accordingly, concluded that this deficiency was a material weakness. Although this material weakness was subsequently remedied, if we are unable to successfully prevent or address these and other material weaknesses in our internal control systems, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC's expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The Chairman of the CFTC has announced that the CFTC intends to conduct hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all over-the-counter (*"OTC"*) derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivative contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Risks Related to an Investment in Our Common Stock

One stockholder holds a significant number of our shares, which will limit your ability to influence corporate activities and may adversely affect the market price of our common stock, and that stockholder's interests may conflict with the interests of our other stockholders.

Of the approximately 38.5 million shares of our common stock outstanding at December 31, 2009, 15.5 million shares are held by OCM GW Holdings, LLC (*"Oaktree Holdings"*). As a result, Oaktree Holdings owns or controls outstanding common stock representing, in the aggregate, an approximate 40.3% voting interest in us. As a result of this stock ownership, Oaktree Holdings will possess significant influence over matters requiring approval by our stockholders, including the adoption of amendments to our certificate of incorporation and bylaws and significant corporate transactions. Such ownership and control may also have the effect of delaying or preventing a future change of control, impeding a merger, consolidation, takeover or other business combination or discouraging a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company.

Oaktree Holdings and its affiliates engage, from time to time in the ordinary course of their respective businesses, in the trading securities of, and investing in, energy companies. As a result, conflicts may arise between the interests of Oaktree Holdings, on the one hand, and the interests of our other stockholders, on the other hand. Oaktree Holdings may, from time to time, compete directly or indirectly with us or prevent us from taking advantage of corporate opportunities. Oaktree Holdings may also pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us.

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock price may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;

- conditions that impact demand for natural gas, crude oil and natural gas liquids;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;
- general market, economic and political conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us or members of our management team; and
- natural disasters, terrorist attacks and acts of war.

In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Also, the provisions of our revolving credit agreement and second lien credit agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of December 31, 2009, we had approximately 2.0 million options to purchase shares of our common stock outstanding, of which 1.2 million were vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our certificate of incorporation and bylaws may make it more difficult for, or prevent a third party from, acquiring control of us without the approval of our board of directors. These provisions:

- permit us to issue, without any further vote or action by the stockholders, additional shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

- require special meetings of the stockholders to be called by the Chairman of the Board, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;
- require business at special meetings to be limited to the stated purpose or purposes of that meeting;

- require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;

- require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and

- permit directors to fill vacancies in our board of directors.

The foregoing factors, as well as the significant common stock ownership by Oaktree Holdings, could discourage potential acquisition proposals and could delay or prevent a change of control.

We are subject to the Delaware business combination law.

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a “business combination” with an “interested stockholder” for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a “business combination” as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an “interested stockholder” as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation’s voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law.

We have "blank check" preferred stock.

Our certificate of incorporation authorizes the board of directors to issue preferred stock without further stockholder action in one or more series and to designate the dividend rate, voting rights and other rights preferences and restrictions. The issuance of preferred stock could have an adverse impact on holders of common stock. Preferred stock is senior to common stock. Additionally, preferred stock could be issued with dividend rights senior to the rights of holders of common stock. Finally, preferred stock could be issued as part of a "poison pill," which could have the effect of deterring offers to acquire our company.

The holders of our common stock do not have cumulative voting rights, preemptive rights or rights to convert their common stock to other securities.

We are authorized to issue 200.0 million shares of common stock, $0.001 par value per share. As of December 31, 2009, there were 38.5 million shares of common stock issued and outstanding. Since the holders of our common stock do not have cumulative voting rights, the holders of a majority of the shares of common stock present, in person or by proxy, will be able to elect all of the members of our board of directors. The holders of shares of our common stock do not have preemptive rights or rights to convert their common stock into other securities.

ITEM 2. Properties

As of December 31, 2009, we operated a majority of our producing wells and held an average 52% working interest. Gross wells are the total wells in which we own a working interest. Net wells are the sum of the fractional working interests we own in gross wells. Substantially all of our properties are located onshore in Texas. As of December 31, 2009, our properties were located in the following regions: East Texas, Southeast Texas, South Texas, Southwest Louisiana and Colorado and Other, although we separately classify all of our non-operated properties in our Non-Operated region. Given our success in 2009 with the first well on our East Texas acreage, the Kardell #1H, we intend to allocate a substantial portion of our drilling capital budget in the next several years to the development of the significant potential that we believe exists in this area.

Proved Reserves

Estimates of proved reserves at December 31, 2009, 2008, and 2007 were prepared by Netherland, Sewell & Associates, Inc. (Netherland, Sewell), our independent consulting petroleum engineers in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The scope and results of their procedures are summarized in a letter which is included as an exhibit to this Annual Report on Form 10-K. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The estimated proved reserves were reviewed by our Corporate Reservoir Engineering group and by certain members of our senior management team. We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates.

The following tables reflect our estimated proved reserves at December 31 for each of the preceding three years. The 2009 information reflects the disposition of substantially all of our Southwest Louisiana properties, resulting in the disposition of 7,631 MMcfe in 2009. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Southwest Louisiana Disposition.”

	2009	2008	2007
Crude Oil (MBbl)			
Developed	1,274	1,616	2,266
Undeveloped	690	948	637
Total	1,964	2,564	2,903
Natural Gas (MMcf)			
Developed	49,075	66,712	67,997
Undeveloped	20,785	29,457	23,242
Total	69,860	96,169	91,239
Natural Gas Liquids (MBbl)			
Developed	1,977	2,423	2,684
Undeveloped	664	976	906
Total	2,641	3,399	3,590
Total MMcfe			
Developed	68,581	90,946	97,697
Undeveloped	28,908	41,001	32,500
Total	97,489	131,947	130,197
Proved developed reserves percentage	70%	69%	75%
PV-10 (in millions)	$ 176.4	$ 291.0	$ 531.4
Estimated reserve life (in years)	7.1	6.9	9.8
Prices utilized in estimates:			
Natural gas ($/MMBtu)	$ 3.87	$ 5.71	$ 6.80
Crude oil ($/Bbl)	$ 57.65	$ 41.00	$ 92.50

Under new SEC rules, prices used in determining our proved reserves as of December 31, 2009 are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prior to the new rules, natural gas prices were based on the Henry Hub spot price at year end and crude oil prices were based upon the West Texas Intermediate posted price at year end. All prices, under both sets of rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves. Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of the new 12-month average pricing rules at December 31, 2009 resulted in proved reserves of approximately 97,489 MMcfe and PV-10 of $176.4 million. Use of the old year-end pricing rules would have resulted in proved reserves of approximately 114,633 MMcfe at December 31, 2009 and PV-10 of $305.0 million.

PV-10

PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and productions costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity. The following table provides a reconciliation of our Standardized Measure to PV-10:

	December 31,		
	2009	**2008**	**2007**
		(in millions)	
Standardized measure of discounted net cash flows	$ 176.4	$ 260.9	$ 399.5
Present value of future income taxes discounted at 10%	—	30.1	131.9
PV-10	$ 176.4	$ 291.0	$ 531.4

The following table reflects our estimated proved reserves by category as of December 31, 2009.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV-10
						(In millions)
Proved developed producing	812	35,198	1,413	48,551	49.8%	$ 101.7
Proved developed non-producing	462	13,877	564	20,031	20.5%	38.8
Proved undeveloped	690	20,785	664	28,907	29.7%	35.9
Total	1,964	69,860	2,641	97,489	100.0%	$ 176.4

Our estimated net proved reserves as of December 31, 2009, were approximately 71.7% natural gas, 16.2% natural gas liquids and 12.1% crude oil and condensate.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 7.1 years based on our proved reserves as of December 31, 2009 and production for the twelve months ended December 31, 2009, excluding the production associated with the Southwest Louisiana properties that were sold in December 2009. During 2009, 3 gross (1.65 net) operated wells and 3 gross (0.87 net) non-operated wells were drilled, all of which were successes. We also drilled one gross (0.52 net) non-operated well in our East Texas acreage, which was a success. In 2010, we currently expect to drill 12 gross (5.9 net) wells. Also, as of December 31, 2009, we had identified 41 proved undeveloped drilling locations and 783 other unproved drilling locations.

Proved Developed Reserves

From December 31, 2008 to 2009, total proved developed reserves decreased from 90.9 Bcfe to 68.6 Bcfe. Of the decrease in proved developed reserves, 14.9 Bcfe was a result of 2009 production, 4.0 Bcfe was the result of negative price revisions, 2.0 Bcfe was the result of negative performance revisions and 3.3 Bcfe was attributable to the sale of our producing properties in Southwest Louisiana. We expect to recover substantially all of the reserves lost to price changes with improvement in future pricing assumptions. Offsetting the decrease in reserves were new proved developed reserves added of 2.1 Bcfe from drilling.

Proved Undeveloped Reserves

From December 31, 2008 to 2009, total proved undeveloped reserves decreased from 41.0 Bcfe to 28.9 Bcfe. Of the decrease in proved undeveloped reserves, 7.1 Bcfe was the result of negative price revisions, 4.4 Bcfe was attributable to the sale of our producing properties in Southwest Louisiana and 0.6 Bcfe related to other reserve revisions. We expect to recover substantially all of the reserves lost to price changes with improvement in future pricing assumptions.

Due to the low natural gas price environment in 2009 and limited capital availability, we did not actively pursue development of any of our undeveloped locations in 2009. Our 2010 plans include development of one or more undeveloped locations. All of our undeveloped locations have been added within the last five years, almost half of which were added in May 2007 with our acquisition of Gulf Coast assets from EXCO. Our financial resources allow us the flexibility to drill all of the remaining undeveloped locations within a five year period from the time the locations were acquired.

Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth as of December 31 for each of the preceding three years, the estimated future net cash flow from and standardized measure of discounted future net cash flows of our proved reserves, which were prepared in accordance with the rules and regulations of the SEC and the Financial Accounting Standards Board. Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of crude oil, natural gas and natural gas liquids production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. Future income taxes were estimated using future cash inflows, future tax depletion expense on existing producing properties and available net operating loss carryforwards that existed at year end. We cannot assure you that the proved reserves will all be developed within the periods used in the calculations or that those prices and costs will remain constant. A standardized measure of discounted future net cash flows is not required to be presented for interim financial presentation dates.

	2009	2008	2007
Future cash inflows	$ 475,007,800	$ 749,121,400	$ 1,125,374,500
Future production and development costs:			
Production	156,581,500	214,969,100	258,028,900
Development	55,021,500	86,068,300	65,779,100
Future cash flows before income taxes	263,404,800	448,084,000	801,566,500
Future income taxes	—	(46,695,950)	(198,920,968)
Future net cash flows after income taxes	263,404,800	401,388,050	602,645,532
10% annual discount for estimated timing of cash flows	(86,982,100)	(140,485,818)	(203,122,453)
Standardized measure of discounted future net cash flows	$ 176,422,700	$ 260,902,233	$ 399,523,079

Under new SEC rules, prices used in determining our proved reserves as of December 31, 2009 are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prior to the new rules, natural gas prices were based on the Henry Hub spot price at year end and crude oil prices were based upon the West Texas Intermediate posted price at year end. All prices are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

Significant Properties

Summary information on our properties by region with proved reserves is provided below as of December 31, 2009.

Regions	Productive Wells: Gross Productive Wells	Productive Wells: Net Productive Wells	Proved Reserves: Crude Oil	Proved Reserves: Natural Gas	Proved Reserves: Natural Gas Liquids	Proved Reserves: Total	PV-10 [(1)]: Amount
			(MBbl)	(MMcf)	(MBbl)	(MMcfe)	($000)
Southeast Texas	26.0	19.7	1,005	15,079	1,000	27,108	$ 73,749
South Texas	88.0	69.1	431	38,860	1,290	49,186	65,481
East Texas	1.0	0.5	—	1,596	—	1,596	2,688
Colorado & Other	19.0	13.7	294	3,456	—	5,221	5,301
Non-Operated [(2)]	163.0	40.2	234	10,869	351	14,378	29,204
Total	297.0	143.2	1,964	69,860	2,641	97,489	$ 176,423

(1) Under new SEC rules, prices used in determining our proved reserves as of December 31, 2009 are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prior to the new rules, natural gas prices were based on the Henry Hub spot price at year end and crude oil prices were based upon the West Texas Intermediate posted price at year end. All prices are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

(2) On December 28, 2009, we closed on the sale of substantially all of our operated and certain non-operated Southwest Louisiana properties. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Southwest Louisiana Disposition."

Production, Price and Cost History

The following table sets forth information associated with our proved reserves regarding production volumes of crude oil, natural gas and natural gas liquids and certain price and cost information as of December 31 for each of the preceding three years. In addition, the following table includes all fields that represent 15% or more of proved reserves within our one geographical area, the United States of America:

	2009	2008	2007
Production volumes			
Natural gas (Mcf):			
Cage Ranch Field	1,148,559	1,102,049	489,086
Felicia Field	3,858,557	6,394,598	3,735,673
Speaks Field	1,280,718	1,184,088	741,283
Other US	4,126,607	4,454,774	4,101,735
Total natural gas (Mcf)	10,414,441	13,135,509	9,067,777
Crude oil (Bbl):			
Cage Ranch Field	23,912	16,559	9,482
Felicia Field	137,545	228,281	127,996
Speaks Field	6,077	8,301	7,591
Other US	159,173	245,002	263,795
Total crude oil (Bbl)	326,707	498,143	408,864
Natural gas liquids (Bbl):			
Cage Ranch Field	60,959	51,508	25,114
Felicia Field	250,936	345,726	205,970
Speaks Field	14,839	25,251	162
Other US	99,361	93,867	54,661
Total natural gas liquids (Bbl)	426,095	516,352	285,907
Total (Mcfe)	14,931,253	19,222,479	13,236,403
Average sales price (1)			
Natural gas per mcf:			
Cage Ranch Field	$ 4.13	$ 8.65	$ 6.30
Felicia Field	4.04	9.12	6.86
Speaks Field	3.81	7.89	6.26
Other US	3.92	8.99	6.86
Total natural gas per mcf	3.97	8.92	6.78
Crude oil per barrel:			
Cage Ranch Field	$ 49.45	$ 90.87	$ 79.70
Felicia Field	54.20	104.01	77.52
Speaks Field	50.75	106.14	80.53
Other US	60.77	98.97	72.48
Total crude oil per barrel	56.99	101.13	74.38
Natural gas liquids per barrel:			
Cage Ranch Field	$ 29.52	$ 49.97	$ 48.93
Felicia Field	27.86	53.89	52.00
Speaks Field	15.33	47.07	61.17
Other US	40.33	53.37	42.52
Total natural gas liquids per barrel	30.57	53.07	49.92
Average sales price per Mcfe	$ 7.49	$ 9.66	$ 8.25
Average production costs per Mcfe (2)			
Cage Ranch Field	$ 1.81	$ 2.40	$ 2.65
Felicia Field	0.75	0.60	0.89
Speaks Field	1.40	1.51	1.37
Other US	1.37	1.42	0.67
Average production costs per Mcfe	1.16	1.08	0.91

(1) Average sales prices are shown exclusive of the settled amounts of our natural gas, crude oil and natural gas liquids hedge contracts.
(2) Average production cost includes natural gas, crude oil and natural gas liquids operating costs and expense workovers, and excludes production and ad valorem taxes.

Productive Wells

The following table shows the number of producing wells we owned by location at December 31, 2009:

	Crude Oil		Natural Gas	
	Gross Wells	Net Wells	Gross Wells	Net Wells
Southeast Texas	6	5.25	20	14.41
South Texas	1	0.59	87	68.51
East Texas	—	—	1	0.52
Colorado & Other	13	8.86	6	4.82
Non-operated [(1)]	15	2.80	148	37.45
Total	35	17.50	262	125.71

(1) On December 28, 2009, we closed on the sale of substantially all of our operated and certain non-operated Southwest Louisiana properties. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Southwest Louisiana Disposition."

In addition, as of December 31, 2009, we had 118 inactive wells and 18 salt water disposal wells.

Developed and Undeveloped Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of natural gas, crude oil and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres. The following table shows the approximate developed and undeveloped acreage that we have an interest in, by location, at December 31, 2009.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Southeast Texas	23,283	12,818	3,865	2,293
South Texas	74,523	39,866	15,646	12,889
East Texas	512	362	16,739	11,582
Colorado & Other	7,370	5,185	9,560	6,692
Southwest Louisiana [(1)]	3,672	759	—	—
Total	109,360	58,990	45,810	33,456

(1) On December 28, 2009, we closed on the sale of substantially all of our operated and certain non-operated Southwest Louisiana properties. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Southwest Louisiana Disposition."

Drilling Results

The following table shows the results of the wells drilled and completed for operated and non-operated properties for each of the last three fiscal years ended December 31, 2009. No crude oil wells were drilled during this time period.

	2009	2008	2007
Gross Gas Wells			
Development	5	20	9
Exploratory	2	5	8
Dry	—	2	4
Total	7	27	21
Net Gas Wells			
Development	2.13	10.74	1.07
Exploratory	0.90	1.05	1.65
Dry	—	0.80	0.72
Total	3.03	12.59	3.44

At December 31, 2009, we had one exploratory well in progress.

Costs Incurred

The following table shows the costs incurred in our crude oil and gas producing activities for the past three years ended December 31, 2009:

	2009	2008	2007
Property Acquisitions:			
Proved	$ (493,532)	$ 60,765,315	$ 238,036,360
Unproved	1,833,949	57,203,337	30,407,525
Development Costs	11,398,237	86,685,192	30,814,788
Exploration Costs	11,815,450	2,520,389	13,405,017
Total	$ 24,554,104	$ 207,174,233	$ 312,663,690

These costs include crude oil and gas property acquisition, exploration and development activities regardless of whether the costs were capitalized or charged to expense, including lease rental expenses and geological and geophysical expenses and changes to the long-lived asset related to our asset retirement obligation.

Property Dispositions

The following table shows crude oil and gas property dispositions for the past three years ended December 31, 2009:

	2009	2008	2007
Oil and gas properties	$ 42,995,459	$ 21,765,688	$ —
Accumulated DD&A	(23,158,221)	(1,659,588)	—
Oil and gas properties, net	$ 19,837,238	$ 20,106,100	$ —

The dispositions resulted in a net loss of $6.8 million and a net gain of $15.2 million for 2009 and 2008, respectively.

ITEM 3. Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations or from disputes with vendors in the normal course of business. During the second quarter of 2009, holders of oil and gas leases in East Texas (Haynesville Shale) filed two causes of action against us alleging breach of contract for not paying lease bonuses on certain oil and gas leases taken by our leasing agent. The damages alleged are approximately $2.4 million and we have received approximately $300,000 in written demands from other holders of leases in this area that we believe may contemplate legal proceedings. We are vigorously defending these lawsuits, and believe we have meritorious defenses. We do not believe that these claims will have a material adverse effect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

PART II

ITEM 5. MARKET FOR OUR COMMON STOCK

Until December 16, 2009 our common stock was traded on the Over-the-Counter Bulletin Board (the "OTCBB") under the symbol "CXPO.OB." Effective December 17, 2009, our common stock began trading on the NASDAQ Global Market under the symbol "CXPO."

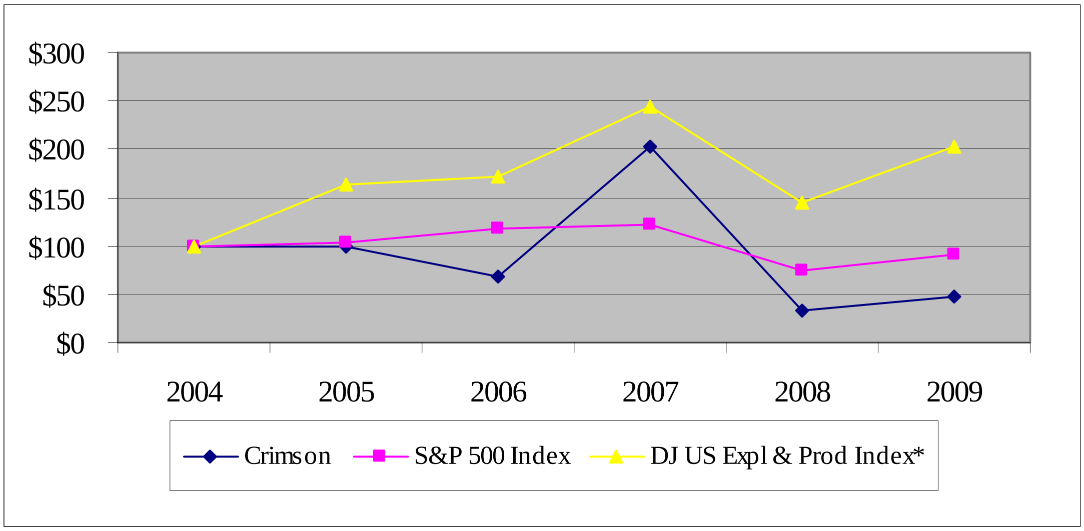
The following table sets forth the range of high and low bid quotation prices per share of our common stock as reported by the OTCBB, except for the fourth quarter 2009 which was reported by NASDAQ. The quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

	High	Low
2009		
First Quarter	$ 4.60	$ 0.80
Second Quarter	4.65	1.75
Third Quarter	4.30	2.26
Fourth Quarter	8.25	3.57
2008		
First Quarter	$ 18.50	$ 9.10
Second Quarter	17.50	8.20
Third Quarter	16.20	7.23
Fourth Quarter	7.43	2.85
2007		
First Quarter	$ 6.20	$ 5.25
Second Quarter	7.55	5.25
Third Quarter	8.35	7.15
Fourth Quarter	19.35	7.65

Stock Performance Chart

The following chart compares the yearly percentage change in the cumulative total stockholder return on our Common Stock during the five years ended December 31, 2009 with the cumulative total return of the Standard and Poor's 500 Stock Index and of the Dow Jones U.S. Exploration and Production Index. The comparison assumes $100 was invested on December 31, 2004 in our Common Stock and in each of the foregoing indices and assumes reinvestment of dividends. We paid no dividends on our Common Stock during such five-year period.

Comparison of Five-Year Cumulative Total Return Among Crimson Exploration, S&P 500 Index and the Dow Jones U.S. Exploration and Production Index



	Crimson	S&P 500 Index	DJ US Expl & Prod Index
December 31, 2004	$ 100.00	$ 100.00	$ 100.00
December 31, 2005	$ 98.90	$ 103.00	$ 164.11
December 31, 2006	$ 68.68	$ 117.03	$ 171.73
December 31, 2007	$ 202.20	$ 121.16	$ 244.91
December 31, 2008	$ 34.07	$ 74.53	$ 145.40
December 31, 2009	$ 48.13	$ 92.01	$ 202.12

General

The following descriptions are summaries of material terms of our common stock, preferred stock, certificate of incorporation and bylaws. This summary is qualified by reference to our certificate of incorporation, bylaws and the designations of our preferred stock, which are filed as exhibits to this Annual Report on Form 10-K, and by the provisions of applicable law.

Common Stock

We are authorized to issue up to 200.0 million shares of Common Stock, par value $0.001 per share. As of March 9, 2010, there were 38.5 million shares of Common Stock issued and outstanding and held by approximately 275 record holders. On December 22, 2009, all shares of preferred stock, including accumulated dividends, were converted into Common Stock in conjunction with our equity offering. Fidelity Transfer Company, 8915 South 700 East #102, Sandy, Utah 84070, (801) 562-1300 is our current transfer agent for our Common Stock. We will be changing our transfer agent for our Common Stock on April 1, 2010 to Continental Stock Transfer & Trust Company, 17 Battery Place, New York, NY 10004.

Holders of Common Stock are entitled to one vote for each share held on record on each matter submitted to a vote of stockholders and, in the event of liquidation, to share ratably in the distribution of assets remaining after payment of liabilities (including preferential distribution and dividend rights of holders of preferred stock). Holders of Common Stock have no cumulative rights. The holders of a plurality of the outstanding shares of the Common Stock have the ability to elect all of the directors.

Holders of Common Stock have no preemptive or other rights to subscribe for shares. Holders of Common Stock are entitled to such dividends as may be declared by the Board out of funds legally available therefor. We have never paid cash dividends on the Common Stock and do not anticipate paying any cash dividends in the foreseeable future.

Preferred Stock

Our board of directors is authorized, without further stockholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series. Any preferred stock that might be issued would be senior to our Common Stock regarding liquidation. The holders of the preferred stock do not have voting rights or preemptive rights, nor are they subject to the benefits of any retirement or sinking fund. We are authorized to issue up to 10.0 million shares of preferred stock. On December 22, 2009, all outstanding shares, and accumulated dividends, of preferred stock that had not previously converted were converted into Common Stock in conjunction with our public offering of Common Stock.

Share-Based Compensation

At December 31, 2009, we had outstanding employee stock options, under our 2004 Stock Option and Compensation Plan, to purchase 16,000 (all vested) shares of Common Stock. On February 28, 2005, we established our 2005 Stock Incentive Plan (*"2005 Plan"*) and authorized the issuance of up to approximately 2.9 million shares of Common Stock pursuant to awards under the plan. In the third quarter 2008, our Board of Directors and a majority of our stockholders approved an amendment and restatement of our 2005 Stock Incentive Plan that provided for an increase in the number of shares of Common Stock available for award under our 2005 Stock Incentive Plan to approximately 3.9 million shares. We also issued 250,000 shares of restricted Common Stock to our executive officers outside of these plans. Approximately 2.0 million (1.2 million vested) stock options and 1.5 million (0.2 million vested) restricted shares were outstanding at December 31, 2009. Option awards outstanding under both plans have exercise prices ranging from $2.40 to $16.55 per share. In 2009 and 2008, respectively, 127,243 and 85,318 shares of restricted Common Stock vested, of which 40,921 and 20,625 shares were withheld by us to satisfy the employees' tax liability resulting from the vesting of these shares, as provided for in the restricted stock agreement, with the remaining shares being released to the employees and associated directors. At December 31, 2009, we had approximately 0.6 million shares of Common Stock available for future grant under the 2005 Plan.

Recent Sales of Unregistered Securities

As shown in the table below, during 2009, 2008 and 2007 we issued Common Stock not registered under the Securities Act of 1933 (*the "Act"*), as amended, in transactions we believe are exempt under Section 4(2) of the Act due to the limited number of persons involved and their relationship with us or in the case of conversions, exempt under Section 3(a)(9) of the Act. No underwriters were used, and no underwriting discounts or commissions were paid in connection with the sales.

Date	Class	Holder(s)	Underlying Shares	Exercise/ Conversion Price	Consideration
12/22/2009	Common Stock	Existing Stockholders	11,800,735	$ 5.00	Series G Preferred Stock Conversion
12/22/2009	Common Stock	Existing Stockholders	300,001	$ 3.50	Series H Preferred Stock Conversion
7/11/2008	Common Stock	Existing Stockholders	14,286	$ 9.00	Series H Preferred Stock Conversion
2/7/2008	Common Stock	Existing Stockholder	34,821	$ 9.00	Series G Preferred Stock Conversion
12/20/2007	Common Stock	Existing Stockholder	50,000	$ 80.00	Series D Preferred Stock Conversion
10/05/2007	Common Stock	Accredited Investors	2,818	NA	Director Compensation
9/28/2007	Common Stock	Accredited Investors	250,000	NA	Compensation to Company’s Executive Officers
5/29/2007	Common Stock	Existing Stockholder	428,572	$ 3.50	Series H Preferred Stock Conversion
5/29/2007	Common Stock	Existing Stockholder	291,247	$ 9.00	Series E Preferred Stock Conversion
5/8/2007	Common Stock	Accredited Investor	750,000	NA	EXCO Acquisition

We withheld the following shares of Common Stock to satisfy tax withholding obligations during the fourth quarter 2009 from the distributions described below. These shares may be deemed to be "issuer purchases" of shares that are required to be disclosed pursuant to this item.

Period	Total Number of Shares Purchased [(1)]	Average price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [(1)]	Maximum Number (or Approximate Dollar Value) of Shares That May Be Purchased Under the Plan or Programs
October 1-31, 2009	208	$ 3.70	208	(1)
November 1-30, 2009	—	—	—	(1)
December 1-31, 2009	—	—	—	(1)
Total	208		208	

(1) Shares were withheld from employees to satisfy certain tax withholding obligations due in connection with grants of stock under our 2005 Stock Incentive Plan. The 2005 Stock Incentive Plan provides from the withholding of shares to satisfy tax obligations.

ITEM 6. Selected Financial Data

The following table sets forth our selected consolidated financial data for the last five years ended as of December 31. This data should be read in conjunction with our Consolidated Financial Statements and the accompanying notes in "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this Form 10-K.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
Statement of Operations Data					
Operating revenues	$112,447,646	$186,768,273	$109,543,208	$ 21,659,481	$ 17,682,808
Income (loss) from operations [(1)]	(387,836)	46,095,294	33,616,299	(2,458,685)	637,823
Net income (loss)	(34,069,990)	46,203,218	(430,517)	1,858,944	(3,543,239)
Dividends on preferred stock	(4,522,645)	(4,234,050)	(4,453,872)	(3,648,925)	(3,562,472)
Net income (loss) available to common stockholders	(38,592,635)	41,969,168	(4,884,389)	(1,789,981)	(7,105,711)
Net income (loss), per share					
Basic	$ (4.91)	$ 7.81	$ (1.13)	$ (0.55)	$ (2.66)
Diluted	$ (4.91)	$ 4.46	$ (1.13)	$ (0.55)	$ (2.66)
Weighted average shares outstanding					
Basic	7,861,054	5,371,377	4,330,282	3,231,000	2,673,882
Diluted	7,861,054	10,360,348	4,330,282	3,231,000	2,673,882

(1) Non-cash equity-based compensation charges were $2.4 million, $5.4 million and $4.7 million, in 2009, 2008 and 2007, respectively.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
Balance Sheet Data					
Current assets	$ 24,710,943	$ 46,347,553	$ 36,481,565	$ 4,231,983	$ 5,825,078
Total assets	424,804,034	511,545,789	398,935,074	84,702,722	63,114,949
Current liabilities	33,486,034	83,989,610	48,879,245	10,932,155	6,855,735
Noncurrent liabilities	208,587,112	305,933,376	280,402,748	12,444,784	3,453,952
Stockholders' equity	182,730,888	121,622,803	69,653,081	61,325,783	52,805,262

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

You should read the following discussion of our results of operations and financial condition with the "Selected Historical Consolidated Financial Data" and the historical financial statements and related notes included elsewhere in this Annual Report. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in the "Risk Factors" section of this Annual Report. Actual results may differ materially from those contained in any forward-looking statements.

Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

In late 2008 and 2009, we acquired approximately 12,000 net acres in East Texas where we completed our first well, the Kardell #1H, in October 2009, which targeted the Haynesville Shale. In addition to the Haynesville Shale, we believe this acreage is equally prospective in the Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations where industry participants have drilled successful wells on adjacent acreage.

In 2007, we acquired approximately 2,800 gross (1,200 net) acres in South Texas, which we believe is prospective in the Austin Chalk and the Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009. It was completed as a vertical well in the first quarter of 2010. The well flowed 600 Mcf per day at 2,400 psi flowing tubing pressure on an 8/64" choke after a small fracture stimulation. The well is currently shut-in due to limited production facilities. Crimson is encouraged by the results from the Dubose #1 and the potential of a future Eagle Ford horizontal well, which we currently have planned for the second half of 2010.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of 824 gross drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91%.

As of December 31, 2009, our proved reserves, as estimated by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., in accordance with new reserve reporting guidelines mandated by the SEC, were 97.5 Bcfe, consisting of 69.9 Bcf of natural gas and 4.6 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2009, 72% of our proved reserves were natural gas, 70% were proved developed and 86% were attributed to wells and properties operated by us. During the last three years, we have grown proved reserves from 46.4 Bcfe to 97.5 Bcfe. In addition, our average daily production increased from 7.3 MMcfe/d for the twelve months ended December 31, 2006 to 40.9 MMcfe/d for the twelve months ended December 31, 2009.

Recent Developments

Equity Offering

On December 22, 2009, we closed on a public offering of 20.0 million shares of Common Stock at $5.00 per share. Cash proceeds, net of underwriting fees, of $94.0 million from this offering were used to repay $84.0 million in outstanding indebtedness under our revolving credit agreement and our $10.0 million unsecured promissory note. Also, on December 17, 2009, we began trading our Common Stock on The NASDAQ Global Market under the ticker symbol “CXPO”.

Amendments to Revolving Credit Agreement

Effective December 7, 2009, we entered into an amendment to our revolving credit agreement that, among other things, amended certain of our financial covenants to improve our financial flexibility and redetermined our borrowing base at January 1, 2010 to $105.0 million. See “—Liquidity and Capital Resources—Capital resources—Revolving Credit Agreement.”

Southwest Louisiana Disposition

On December 28, 2009, we closed on a definitive agreement to sell operated and non-operated working interests in various producing wells, related production equipment and associated acreage primarily in Cameron, Calcasieu and Jefferson Davis parishes in Southwest Louisiana, with an effective date of October 1, 2009. The final total consideration paid by the buyer of $7.8 million was based on existing wells and undeveloped acreage owned by us at the time of the closing. The assets include substantially all of our Southwest Louisiana properties, representing approximately 7.6 Bcfe of proved reserves as of September 30, 2009, with average daily production of approximately 3.1 Mmcfe/d for the year ended December 31, 2009. The net proceeds of $7.3 million, after adjustment of $0.5 million for revenues and expenses incurred during the period from the effective date through the date of sale, were primarily used to repay amounts outstanding under our senior revolving credit agreement. Our net book value of these assets was $18.8 million and the estimated plug and abandon liabilities assumed by the buyer on these assets were $5.3 million, which resulted in a loss of $6.2 million. The agreement provides for up to an additional $2.4 million in gross proceeds for the sale of additional properties for which various consents are still being solicited. We have 180 days from the closing date to obtain these consents. The sale of these non-core assets represents a strategic exit from operations in Southwest Louisiana.

East Texas Acreage Acquisition

In the second half of 2008 and the full year 2009, we obtained natural gas and crude oil leases from mineral interest owners covering approximately 17,300 gross (12,000 net) acres in the natural gas resource play in East Texas specifically in San Augustine and Sabine Counties. We commenced our first well (the Kardell #1H), in which we owned a 52% working interest, in this play in late June 2009 and completed that well in October 2009. The well had a measured depth of approximately 18,350 feet and was a successful test of the Haynesville Shale formation. We plan to continue to pursue an active drilling program in this area for the next several years, targeting primarily the Haynesville Shale, Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations. We financed the acquisition of this acreage with cash flows from operations and from borrowings available under our revolving credit agreement.

Results of Operations

The following is a discussion of our consolidated results of operations, financial condition and capital resources. You should read this discussion in conjunction with our Consolidated Financial Statements and the Notes thereto contained elsewhere in this Form 10-K.

Comparative results of operations for the periods indicated are discussed below.

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

Revenues

	2009	2008	Change	Percent Change
		(in millions, except percentages)		
Product Revenues:				
Natural gas sales	$ 71.5	$ 116.4	$ (44.9)	-38.6%
Crude oil sales	27.3	41.9	(14.6)	-34.8%
Natural gas liquids sales	13.0	27.4	(14.4)	-52.6%
Product revenues	$ 111.8	$ 185.7	$ (73.9)	-39.8%

Natural Gas, Crude Oil And Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, declined to $111.8 million in 2009 compared to $185.7 million in 2008. The decrease in net revenues was primarily due to a decrease in production and realized commodity prices.

	2009	2008	Change	Percent Change
Sales volumes:				
Natural gas (Mcf)	10,414,441	13,135,509	(2,721,068)	-20.7%
Crude oil (Bbl)	326,707	498,143	(171,436)	-34.4%
Natural gas liquids (Bbl)	426,095	516,352	(90,257)	-17.5%
Natural gas equivalents (Mcfe)	14,931,253	19,222,479	(4,291,226)	-22.3%

Sales volumes decreased to 14.9 Bcfe in 2009 from 19.2 Bcfe in 2008. On a daily basis we produced an average of 40,908 Mcfe in 2009 compared to an average of 52,520 Mcfe in 2008. Production volumes decreased primarily due to natural field decline and limited production-enhancing capital expenditure activity in 2009.

	2009	2008	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 3.97	$ 8.92	$ (4.95)	-55.5%
Crude oil (Bbl)	56.99	101.13	(44.14)	-43.6%
Natural gas liquids (Bbl)	30.57	53.07	(22.50)	-42.4%
Natural gas equivalents (Mcfe)	4.89	10.14	(5.25)	-51.8%

	2009	2008	Change	Percent Change
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 6.86	$ 8.86	$ (2.00)	-22.6%
Crude oil (Bbl)	83.51	84.03	(0.52)	-0.6%
Natural gas liquids (Bbl)	30.57	53.07	(22.50)	-42.4%
Natural gas equivalents (Mcfe)	7.49	9.66	(2.17)	-22.5%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $8.7 million on our crude oil hedges and $30.1 million on our natural gas hedges in 2009, compared to realized losses of $8.5 million for crude oil hedges and realized gains of $0.8 million for natural gas hedges in 2008.

Operating Overhead and Other Income. Revenues representing overhead cost reimbursements billed to working interest partners on operated properties decreased to $0.6 million in 2009 compared to $1.1 million in 2008 due to the one-time catch up in the third quarter 2008 on overhead billings.

Costs and Expenses

	2009	2008	Change	Percent Change
Certain Operating Expenses:		(in millions, except percentages)		
Lease operating expenses	$ 17.4	$ 20.8	$ (3.4)	-16.3%
Production and ad valorem taxes	7.1	16.3	(9.2)	-56.4%
Exploration expenses	3.8	10.0	(6.2)	-62.0%
General and administrative (1)	16.4	17.0	(0.6)	-3.5%
Operating expenses (cash)	44.7	64.1	(19.4)	-30.3%
Depreciation, depletion & amortization	53.3	50.5	2.8	5.5%
Share-based compensation (1)	2.4	5.4	(3.0)	-55.6%
Certain operating expenses (2)	$ 100.4	$ 120.0	$ (19.6)	-16.3%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations
(2) Exclusive of impairment and abandonment of proved properties and sales of assets

	2009	2008	Change	Percent Change
Selected Costs ($ per Mcfe):		(in millions, except percentages)		
Lease operating expenses	$ 1.16	$ 1.08	$ 0.08	7.4%
Production and ad valorem taxes	0.48	0.85	(0.37)	-43.5%
Exploration expenses	0.25	0.52	(0.27)	-51.9%
General and administrative (1)	1.10	0.88	0.14	25.0%
Operating expenses (cash)	2.99	3.33	(0.42)	-10.2%
Depreciation, depletion & amortization	3.57	2.63	0.94	35.7%
Share-based compensation (1)	0.16	0.28	(0.12)	-42.9%
Selected costs	$ 6.72	$ 6.24	$ 0.40	7.7%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations

Lease Operating Expenses. Lease operating expenses for 2009 were $17.4 million, compared to $20.8 million in 2008, a decrease resulting from the implementation of cost reduction initiatives during 2009 and generally lower costs of goods and services in the industry.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2009 were $7.1 million, compared to $16.3 million in 2008, a decrease resulting from lower production and lower prices in 2009.

Exploration Expenses. Total exploration expenses were $3.8 million in 2009 compared to $10.0 million in 2008. The decrease in exploration expenses was primarily due to abandonment expenses of unproved properties which were $1.1 million in 2009, compared to $7.4 million in 2008 resulting from the release and abandonment of the undeveloped leasehold position that we acquired from Core Natural Resources in Culberson County, Texas.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense for 2009 was $53.3 million compared to $50.5 million in 2008, due to a higher DD&A rate resulting predominately from the effect of negative price-related reserve revisions offset by lower production in 2009.

Impairment and Abandonment of Proved Properties. Impairment and abandonment of proved properties non-cash expense for 2009 was $5.7 million compared to $36.0 million in 2008. In 2009 we incurred $1.5 million in non-cash impairment expense in South Texas and $1.1 million in Southwest Louisiana and abandoned $2.5 million related to our Alwan Field in South Texas. In 2008, we incurred $10.2 million in non-cash impairment expense for our Grand Lake Field in Southwest Louisiana and $25.8 million for our Madisonville Field in Southeast Texas.

General and Administrative ("G&A") Expenses. Our G&A expenses were $18.8 million for 2009 compared to $22.4 million in 2008. The reduction in G&A expenses is primarily a result of the implementation of cost reduction initiatives during 2009 and the decrease in non-cash stock expense of $2.4 million ($0.16 per Mcfe) in 2009 compared with $5.4 million ($0.28 per Mcfe) for 2008.

Loss (Gain) on Sale of Assets. Loss on the sale of assets for 2009 was $6.8 million compared to a gain on sale of assets of $15.2 million in 2008. The net loss on the sale of assets was primarily the result of the sale of our non-core Southwest Louisiana properties. The gain on the sale of assets in 2008 was primarily due to the disposition of our interest in the Barnett Shale Play in the first quarter 2008, which resulted in a gain of $15.6 million.

Interest Expense. Interest expense was $23.2 million for 2009, up from $21.1 million in 2008. Total interest expense increased primarily due to a higher debt balance on our revolving credit agreement and higher interest rates on our second lien credit agreement. Total interest expense capitalized for 2009 and 2008 was $25,000 and $0.9 million, respectively.

Other Financing Costs. Other financing costs were $3.3 million for 2009 compared with $1.5 million for 2008. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and of commitment fees related to the unused portion of the credit agreements. In 2009 we also fully amortized the $1.7 million in debt issuance costs associated with the $10.0 million bridge loan that was paid off in December 2009.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swaps. This non-cash unrealized loss was $23.9 million for 2009 compared with a non-cash unrealized gain of $49.4 million for 2008. Unrealized gain or loss will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges, and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $50.8 million for 2009 compared to net income before taxes of $72.9 million in 2008. After adjusting for permanent tax differences, we recorded income tax benefit of $16.7 million for 2009, of which $0.1 million was current tax expense and $16.6 million was deferred. We recorded income tax expense of $26.7 million for 2008 of which $0.6 million was current and $26.1 million was deferred. Our effective tax rates differ from the statutory rate of 35% primarily because of state and local taxes and the tax effects of permanent book-tax differences.

Dividends on Preferred Stock. Dividends on preferred stock were $4.5 million in 2009 compared with $4.2 million in 2008. All of the Series G and H Preferred Stock, including accrued dividends, were converted to Common Stock in December 2009 in conjunction with our Common Stock offering. Dividends in 2009 included $4.4 million on the Series G Preferred Stock and $0.1 million on the Series H Preferred Stock.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues

	2008	2007	Change	Percent Change
		(in millions, except percentages)		
Product Revenues:				
Natural gas sales	$ 116.4	$ 67.9	$ 48.5	71.4%
Crude oil sales	41.9	27.0	14.9	55.2%
Natural gas liquids sales	27.4	14.3	13.1	91.6%
Total operating revenues	$ 185.7	$ 109.2	$ 76.5	70.1%

Natural Gas, Crude Oil And Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, increased to $185.7 million in 2008 compared to $109.2 million in 2007. The increase in net revenues was primarily due to the effect of the STGC Properties acquisition in May 2007, which significantly increased our production volumes.

	2008	2007	Change	Percent Change
Sales volumes:				
Natural gas (Mcf)	13,135,509	9,067,777	4,067,732	44.9%
Crude oil (Bbl)	498,143	408,864	89,279	21.8%
Natural gas liquids (Bbl)	516,352	285,907	230,445	80.6%
Natural gas equivalents (Mcfe)	19,222,479	13,236,403	5,986,076	45.2%

Sales volumes increased to 19.2 Bcfe in 2008 from 13.2 Bcfe in 2007 primarily due to the full-year effect in 2008 of the May 2007 acquisition of the STGC Properties and the seven-month effect of the May 2008 Smith acquisition, offset by approximately 425,000 Mcfe of production and natural gas liquids not processed in the third and fourth quarters of 2008 due to Hurricanes Gustav and Ike. On a daily basis we produced an average of 52,520 Mcfe in 2008 compared to an average of 36,264 Mcfe in 2007.

	2008	2007	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 8.92	$ 6.78	$ 2.14	31.6%
Crude oil (Bbl)	101.13	74.38	26.75	36.0%
Natural gas liquids (Bbl)	53.07	49.92	3.15	6.3%
Natural gas equivalents (Mcfe)	10.14	8.02	2.12	26.4%

	2008	2007	Change	Percent Change
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 8.86	$ 7.48	$ 1.38	18.4%
Crude oil (Bbl)	84.03	66.09	17.94	27.1%
Natural gas liquids (Bbl)	53.07	49.92	3.15	6.3%
Natural gas equivalents (Mcfe)	9.66	8.25	1.41	17.1%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized losses of $8.5 million on our crude oil hedges and $0.8 million on our natural gas hedges in 2008, compared to realized losses of $3.4 million for crude oil hedges and realized gains of $6.4 million for natural gas hedges in 2007.

Operating Overhead and Other Income. Revenues from working interest partners increased to $1.1 million in 2008 compared to $0.4 million in 2007 due to the increase in administrative overhead fees charged to our partners on the operated acquired properties and the one-time catch up in the third quarter 2008 on overhead billings due to the increase in COPAS rates.

Costs and Expenses

	2008	2007	Change	Percent Change
Certain Operating Expenses:		(in millions, except percentages)		
Lease operating expenses	$ 20.8	$ 12.0	$ 8.8	73.3%
Production and ad valorem taxes	16.3	11.7	4.6	39.3%
Exploration expenses	10.0	3.2	6.8	212.5%
General and administrative (1)	17.0	9.8	7.2	73.5%
Operating expenses (cash)	64.1	36.7	27.4	74.7%
Depreciation, depletion & amortization	50.5	30.8	19.7	64.0%
Share-based compensation (1)	5.4	4.7	0.7	14.9%
Certain operating expenses (2)	$ 120.0	$ 72.2	$ 47.8	66.2%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations
(2) Exclusive of impairment and abandonment of proved properties and sales of assets

Selected Costs ($ per Mcfe):	2008	2007	Change	Percent Change
		(in millions, except percentages)		
Lease operating expenses	$ 1.08	$ 0.91	$ 0.17	18.7%
Production and ad valorem taxes	0.85	0.88	(0.03)	-3.4%
Exploration expenses	0.52	0.24	0.28	116.7%
General and administrative (1)	0.88	0.74	0.14	18.9%
Operating expenses (cash)	3.33	2.77	0.56	20.2%
Depreciation, depletion & amortization	2.63	2.33	0.30	12.9%
Share-based compensation (1)	0.28	0.36	(0.08)	-22.2%
Selected costs	$ 6.24	$ 5.46	$ 0.78	14.3%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations

Lease Operating Expenses. Lease operating expenses for 2008 were $20.8 million, compared to $12.0 million in 2007. The increase in lease operating expenses was primarily due to the addition of the STGC properties and the South Texas properties from the Smith acquisition, increased workovers and general increases in the costs of goods and services in the industry.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2008 were $16.3 million, compared to $11.7 million in 2007. The increase in production and ad valorem tax expenses was primarily due to higher production and realized prices in 2008.

Exploration Expenses. Total exploration expenses were $10.0 million in 2008 compared to $3.2 million in 2007. The significant increase in exploration expenses was primarily due to the release and abandonment of the undeveloped leasehold position that we acquired from Core Natural Resources in Culberson County, Texas which resulted in leasehold abandonment cost of $7.1 million in 2008.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense for 2008 was $50.5 million compared to $30.8 million in 2007, as a result of a higher DD&A rate and higher production volumes, from the full-year effect in 2008 of the May 2007 acquisition of the STGC Properties and the seven-month effect of the May 2008 Smith acquisition.

Impairment and Abandonment of Proved Properties. Impairment and abandonment expense for 2008 was $36.0 million compared to $4.4 million in 2007. In December 2008, we recorded a non-cash impairment expense of $10.2 million, primarily related to our Grand Lake Field in Southwest Louisiana, resulting from negative reserve revisions related to low commodity prices at year end. In September 2008, we recorded a non-cash impairment expense of $25.8 million related to our decision to discontinue development of the Rodessa formation in our Madisonville Field in our Southeast Texas Region.

General and Administrative ("G&A") Expenses. Our G&A expenses were $22.4 million for 2008 compared to $14.5 million in 2007. Included in G&A expense is a non-cash stock expense of $5.4 million ($0.28 per Mcfe) and $4.7 million ($0.36 per Mcfe) for 2008 and 2007, respectively. G&A expenses increased primarily due to higher personnel costs, higher professional fees and higher office rent expense related to expanding our infrastructure.

Gain on Sale of Assets. Gain on the sale of assets for 2008 was $15.2 million. The net gain on the sale of assets was primarily due to the disposition of our interest in the Barnett Shale Play in the first quarter 2008, which resulted in a gain of $15.6 million. The gain on the sale of assets in 2007 was $0.7 million.

Interest Expense. Interest expense was $21.1 million for 2008, up from $14.9 million in 2007. Total interest expense increased primarily as a result of higher outstanding loan balances on our credit agreements related to our acquisition and drilling activity. Total interest expense capitalized for 2008 and 2007 was $0.9 million and $1.3 million, respectively.

Other Financing Costs. Other financing costs were $1.5 million for 2008 compared with $1.3 million for 2007. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and of commitment fees related to the unused portion of the credit agreements.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swaps. This non-cash unrealized gain for 2008 was $49.4 million compared with a non-cash unrealized loss of $18.2 million for 2007. Unrealized gain or loss will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges, and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net income before taxes was $72.9 million for 2008 compared to a net loss before taxes of $0.8 million in 2007. After adjusting for permanent tax differences, we recorded income tax expense of $26.7 million for 2008, of which $0.6 million was current tax expense and $26.1 million was deferred. The income tax benefit of $0.4 million for 2007 was all deferred. Our effective tax rates differ from the statutory rate of 35% primarily because of state and local taxes and the tax effects of permanent book-tax differences.

Dividends on Preferred Stock. Dividends on preferred stock were $4.2 million for 2008 compared with $4.5 million in 2007. Dividends in 2008 included $4.1 million on the Series G Preferred Stock and $0.1 million on the Series H Preferred Stock. Dividends in 2007 included $4.3 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.1 million on the Series E Preferred Stock. All of the Series E Preferred Stock was converted to Common Stock in May 2007.

Critical Accounting Policies and Estimates

The discussion and analysis of financial condition and results of our operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate such estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of the more significant accounting policies, estimates and judgments. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of our financial statements. Please read the notes to our audited consolidated financial statements included in this Annual Report for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method

We use the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed (except those costs used to determine a drill site location).

Revenue Recognition

We follow the “sales” method of accounting for natural gas, crude oil and natural gas liquids revenues. Under this method, we recognize revenues on production as it is taken and delivered to its purchasers. The volumes sold may be more or less than the volumes we are entitled to based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. Our crude oil and natural gas imbalances are not significant.

Depletion and Depreciation

The estimates of natural gas, crude oil and natural gas liquids reserves utilized in the calculation of depletion and depreciation are estimated in accordance with guidelines established by the Society of Petroleum Engineers, the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized natural gas, crude oil and natural gas liquids costs on the unit of production method, based upon these reserve estimates. It is reasonably possible that the estimates of future cash inflows, future gross revenues, the amount of natural gas, crude oil and natural gas liquids reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Impairments

We assess all of our properties for possible impairment on an annual basis as a minimum, or as circumstances warrant, based on geological trend analysis, changes in proved reserves or relinquishment of acreage. When impairment occurs, the adjustment is recorded to accumulated depletion. See the discussion of impairment expenses in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our natural gas, crude oil and natural gas liquids wells and associated pipelines and equipment. The liability and the associated increase in the related long-lived asset are recorded in the period in which our asset retirement obligation, or ARO, is incurred. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to acquisitions and dispositions, changes in estimates of plugging and abandonment costs, changes in the risk-free rate or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we recognize a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs.

Derivative Instruments

At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments.

Recent Accounting Pronouncements

New Accounting Standards Adopted in 2009

Accounting Standards Codification — On July 1, 2009, the Financial Accounting Standards Board ("*FASB*") instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The FASB *Accounting Standards Codification*™ ("*ASC*") is now the single authoritative source for GAAP. Although the implementation of ASC had no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

FASB Accounting Standards Update (*"ASU"*) 2010-03 was issued on January 6, 2010, and aligns the current oil and natural gas reserve estimation and disclosure requirements of ASC 932 with those in the *SEC Final Rule*

Modernization of Oil and Gas Reporting issued December 31, 2008. The rules only apply prospectively as a change in estimate. The most significant amendments to the reserve and disclosure requirements include the following:

- Commodity Prices—Economic producibility of reserves and discounted cash flows will be based on an unweighted arithmetic average of the first day of the month commodity price during the 12-month period ending on the balance sheet date unless contractual arrangements designate the price to be used.

- Disclosure of Unproved Reserves—Probable and possible reserves may be disclosed separately on a voluntary basis.

- Proved Undeveloped Reserve Guidelines—Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.

- Reserve Estimation Using New Technologies—Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- Reserve Personnel and Estimation Process—Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- Disclosure by Geographic Area—Reserves in foreign countries or continents must be presented separately if they represent more than 15% of our total oil and natural gas proved reserves.

- Non-Traditional Resources—The definition of oil and natural gas producing activities will expand and focus on the marketable product rather than the method of extraction.

ASU 2010-03 is effective for entities with annual reporting periods ending on or after December 31, 2009. We adopted both the FASB and the SEC rules as of December 31, 2009. Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of the new 12-month average pricing rules at December 31, 2009 resulted in proved reserves of approximately 97,489 MMcfe and PV-10 of $176.4 million. Use of the old year-end pricing rules would have resulted in proved reserves of approximately 114,633 MMcfe at December 31, 2009 and PV-10 of $305.0 million.

Adoption of ASU 2009-05 — In August 2009, the Financial Accounting Standards Board ("*FASB*") issued Accounting Standards Update ("*ASU*") No. 2009-05, *Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value.* ASU 2009-05 provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. We adopted ASU No. 2009-05 (FASB ASC 820-10) as of September 30, 2009. The adoption of this statement did not have an impact on our financial position or results of operations.

Interim Disclosures about Fair Value of Financial Instrument — We adopted FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments", which is now incorporated into ASC Topic No. 825 ("*ASC 825*") as of June 30, 2009. This statement increases the frequency of fair value disclosures to a quarterly instead of annual basis. The guidance relates to fair value disclosures for any financial instruments that are not currently reflected on the balance sheet at fair value. The adoption of this statement did not have a material impact on our financial position or results of operations.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly — We adopted the FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" which is now incorporated into ASC Topic No. 820 ("*ASC 820*") as of June 30, 2009. ASC 820 provides guidelines for a broad interpretation of when to apply market-based fair value measures. It reaffirms management's need to use judgment to determine when a market that was once active has become inactive and in determining fair values in markets that are no longer active.

Disclosure about Derivative Instruments and Hedging Activities — We adopted FASB Statement No. 161, "Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" which is now incorporated into ASC Topic No. 815 ("*ASC 815*") as of January 1, 2009. ASC 815 amends and expands the disclosure requirements for derivative instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for; and (iii) how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. See Note 7 – "Derivative Instruments" for these additional disclosures. The adoption of this statement did not have an impact on our financial position or results of operations.

Business Combinations — We adopted SFAS No. 141 (Revised 2007) "Business Combinations" which is now incorporated into ASC Topic No. 805 ("*ASC 805*") as of January 1, 2009. The revision broadens the definition of a business combination to include all transactions or other events in which control of one or more businesses is obtained. Further, this statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. The adoption of this statement has not had an impact on our financial position or results of operations, because we have not yet had any business combinations in 2009.

Effective Date of FASB Statement No. 157 - We also adopted FSP SFAS 157-2, "Effective Date of FASB Statement No. 157", which is also now incorporated into ASC Topic No. 820 as of January 1, 2009. The effective date was deferred for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually) to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. See Note 5 – "Fair Value Measurements" for additional disclosures. The adoption of this statement did not have a material impact on our financial position or results of operations.

Accounting Standards Not Yet Adopted

Accounting Standards Update ("ASU") 2010-06 — In January 2010, the Financial Accounting Standards Board ("*FASB*") issued ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements.* ASU 2010-06 requires reporting entities to provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy established by FASB ASC 820. The guidance is effective for any fiscal year that begins after December 15, 2010 and should be used for quarterly and annual filings. We will adopt the provisions of ASU 2010-06 on January 1, 2010 and do not anticipate that this standard will have a material impact on our financial position, results of operations or cash flows.

Commitments and Contingencies

The following table provides information about our obligations as of December 31, 2009:

	Long-term debt (3)	Interest	Operating leases (2)	Asset retirements	Executive compensation	ASC Topic 740 (1)
2010	$ 19,014	$ 16,390,000	$ 1,951,198	$ 330,287	$ 1,516,300	$ —
2011	41,000,000	15,596,650	1,437,749	393,507	710,000	—
2012	152,000,000	5,461,800	1,419,933	369,543	—	—
2013	—	—	1,419,933	409,623	—	—
2014	—	—	118,328	428,085	—	—
Thereafter	—	—	—	7,771,608	—	—
Total	$ 193,019,014	$ 37,448,450	$ 6,347,141	$ 9,702,653	$ 2,226,300	$ 518,219

(1) FASB ASC Topic 740 (previously reported as FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, An interpretation of FASB Statement No. 109"). We cannot predict at this time when this obligation may be required to be paid, if at all.

(2) Operating leases include contracts related to office space, compressors, vehicles, office equipment and other.

(3) Includes subordinated promissory note which is shown net of discount of $250,249 on the Consolidated Balance Sheets and in Note 10 "Debt".

Liquidity and Capital Resources

Our primary cash requirements are for capital expenditures, working capital, operating expenses, acquisitions and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations, net of the realized effect of our hedging agreements, and amounts available to be drawn under our revolving credit agreement. To the extent our cash requirements exceed our sources of liquidity, we will be required to fund our cash requirements through other means, such as through debt and equity financing activities and/or asset monetizations, and/or curtail capital expenditures.

Liquidity and cash flow

During the last year there has been volatility and disruption in the equity and debt markets. The volatility and disruptions have created conditions and/or business strategies that have adversely affected the financial condition of some of our lenders, the counterparties to our derivative instruments, our insurers and our crude oil and natural gas purchasers. While in recent months market conditions have stabilized, continued economic uncertainty may limit our ability to access the equity and debt markets. In addition, though a substantial portion of our production is hedged, we are still subject to commodity price risk and our liquidity may be adversely affected if commodity prices were to decline.

Our working capital deficit was $8.8 million as of December 31, 2009, compared to a working capital deficit of $37.7 million as of December 31, 2008. The following table provides the components and changes in working capital as of December 31, 2009 and 2008, respectively.

	2009	2008	Change
Current assets			
Accounts receivable - trade, net	$ 14,773,246	$ 21,078,815	$ (6,305,569)
Prepaid expenses	—	77,293	(77,293)
Derivative instruments	9,937,697	25,191,445	(15,253,748)
Total current assets	24,710,943	46,347,553	(21,636,610)
Current liabilities			
Current portion of long-term debt	19,014	90,368	(71,354)
Accounts payable and accrued liabilities	29,115,653	72,145,918	(43,030,265)
Income tax payable	250,931	546,944	(296,013)
Asset retirement obligations	330,287	1,659,371	(1,329,084)
Derivative instruments	872,849	1,265,801	(392,952)
Deferred tax liability, net	2,897,300	8,331,208	(5,430,917)
Total current liabilities	33,486,034	84,039,610	(50,550,585)
Working capital (deficit)	$ (8,775,091)	$ (37,692,057)	$ 28,913,975

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the past three years ended December 31, 2009, 2008 and 2007.

	Year Ended December 31,		
	2009	**2008**	**2007**
Financial Measures		(in millions)	
Net cash provided by operating activities	$ 9.7	$ 143.8	$ 69.6
Net cash used in investing activities	(13.8)	(165.4)	(311.8)
Net cash provided by financing activities	4.2	16.7	247.0
Cash and cash equivalents	—	—	4.9
Capital expenditures, including acquisitions	21.4	200.3	312.5

Net cash provided by operating activities was $9.7 million for the twelve months ended December 31, 2009, compared to $143.8 million for the twelve months ended December 31, 2008, a change resulting primarily from the reduction in revenues, accounts payable and accrued liabilities during 2009. During 2009, the net cash provided by operating activities, before changes in working capital, was $46.8 million. Net cash provided by operating activities in 2008, before changes in working capital, was $107.0 million.

Net cash used in investing activities was $13.8 million for the twelve months ended December 31, 2009 compared to $165.4 million for the twelve months ended December 31, 2008. Net cash used for investing activities during the twelve months ended December 31, 2009 was primarily expenditures of $21.4 million related to our 2009 capital program, offset primarily by $7.3 million in cash proceeds from the sale of certain Southwest Louisiana properties. Net cash used in investing activities for the twelve months ended December 31 2008 was primarily for the $58.5 million Smith acquisition and $141.8 million for capital expenditures for the development of our Southeast Texas properties, offset primarily by $34.9 million in proceeds from the sale of our interest in the Barnett Shale Play.

Net cash provided by financing activities was $4.2 million for the twelve months ended December 31, 2009 compared to $16.7 million for the twelve months ended December 31, 2008. Net cash provided by financing activities during the twelve months ended December 31, 2009 was primarily the result of net proceeds of $92.9 million from the sale of stock, offset by net repayments of outstanding borrowings of $85.7 million under our revolving credit agreement. Net cash provided by financing activities for the twelve months ended December 31, 2008 was primarily the result of increased net borrowings of $16.6 million under our revolving credit agreement.

Capital resources

We have a $400.0 million revolving credit agreement with Wells Fargo Bank, National Association, as agent, and the lender parties thereto. The borrowing base under this agreement, based on our crude oil and natural gas reserves, is currently set at $105.0 million. The next borrowing base re-determination under our revolving credit agreement is scheduled for May 1, 2010 and is subject to semi-annual redeterminations, although our lenders may elect to make one additional redetermination between scheduled redetermination dates. Our revolving credit agreement has a term of four years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2011. Our revolving credit agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit. Although this agreement contains restrictions on our ability to incur debt, we may issue up to $200.0 million in senior unsecured notes. Any such issuance of senior unsecured notes will reduce our borrowing base by 25% of the net proceeds from such issuance in excess of $150 million.

Advances under our revolving credit agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the higher of the lender's "prime rate" and the Federal Funds rate. The interest rate on the LIBOR loans fluctuates based upon the rate at which Eurodollar deposits in the LIBOR market are quoted for the maturity selected. Pursuant to an amendment to our revolving credit agreement, dated July 31, 2009, the applicable margin was increased from between 1.25% and 2.00% to between 2.75% and 3.50%, for LIBOR loans, and from zero and 0.50% to between 1.50% and 2.00%, for base rate loans. The specific applicable interest margin is determined by, in each case, the percent of the borrowing base utilized at the time of the credit extension. LIBOR loans of one, two, three and six months may be selected. Pursuant to that same amendment, the commitment fee payable on the unused portion of our borrowing base was increased from 0.375% to 0.50%, which fee accrues and is payable quarterly in arrears.

We also have a second lien credit agreement with Credit Suisse, as agent, and the lender parties thereto which provided for term loans, made to us in a single draw, in an aggregate principal amount of $150.0 million. Our second lien credit agreement replaced our then existing $150.0 million subordinate credit agreement, which was paid off in full and terminated at closing. Our second lien credit agreement matures on May 8, 2012.

Advances under our second lien credit agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the higher of (i) the "prime rate", (ii) the Federal Funds Effective Rate plus ½ of 1% and (iii) the LIBO rate for a one month interest period plus 1.50%. The applicable margin for base rate loans is 7.0%, unless we meet certain leverage and PV-10 ratios, in which case the applicable margin will be 6.0%. The interest rate on the LIBOR loans fluctuates based upon the higher of (i) 3.0% per annum and (ii) the LIBOR rate per annum. The applicable margin for LIBOR loans is 8.0%, unless we meet certain leverage and PV-10 ratios, in which case the applicable margin will be 7.0%.

Our revolving credit agreement and second lien credit agreement are secured by liens on substantially all of our assets, including the capital stock of our subsidiaries. The liens securing the obligations under our second lien credit agreement are junior to those under our revolving credit agreement. Unpaid interest is payable under our credit agreements as borrowings mature and renew.

We utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil and natural gas liquids production. As of December 31, 2009, we had 11.6 MMcfe of equivalent production hedged representing 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 250 MBbl and 124 MBbl of crude oil hedges in place for 2010 and 2011, respectively. We used a series of swaps and costless collars to accomplish our commodity hedging position. We also constructively fixed the base LIBOR on $200.0 million of our variable rate debt by entering into interest rate swaps at a weighted average swap price of 2.6%.

At March 9, 2010, we had $39.0 million outstanding under our revolving credit agreement and $150.0 million outstanding under our second lien credit agreement, with availability under our revolving credit agreement of $66.0 million.

Covenant compliance

Our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our compliance with these covenants is tested each quarter. At December 31, 2009, we were in compliance with the covenants under our revolving credit agreement and second lien credit agreements. See Note 10 —"Debt" for a more detailed description of terms and provisions of our credit agreements.

Future capital requirements

Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We intend to grow our reserves and production by further exploiting our existing property base, through drilling opportunities identified in our new resource plays in East and South Texas and in our conventional inventory. We expect to focus much of our drilling activity over the next several years on continued development of our East Texas and South Texas resource plays while we continue the development and exploitation of our core legacy properties in the South Texas and Gulf Coast areas. We anticipate that acquisitions, including undeveloped leasehold interests, will continue to play a role in our business strategy as those opportunities periodically arise from time to time. While there are currently no unannounced agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly and could occur at any time.

We believe that our internally generated cash flow combined with access to our revolving credit agreement will be sufficient to meet the liquidity requirements necessary to fund our daily operations, planned capital development and execute on our growth strategy and debt service requirements for the next 12 months. Our ability to execute on our growth strategy will be determined, in large part, by our cash flow and the availability of debt and equity capital at that time, and we continuously evaluate our financing opportunities. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as the recent disruption in the capital and credit markets, as well as continued commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our revolving credit agreement in connection with a borrowing base redetermination. In such case, we may be required to seek other sources of capital earlier than anticipated, although the restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all. See "Risk Factors—Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements," "Risk Factors—Our development and exploration operations, including on our East Texas 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 properties and a decline in our natural gas, crude oil and natural gas liquids reserves" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our 2010 capital budget is currently forecast to be approximately $50 million, exclusive of acquisitions. We expect to spend approximately 72% of our budget on our East Texas and South Texas resource plays and 28% on our existing producing assets. We plan to drill 12 gross (5.9 net) wells in 2010, including 7 gross (3.1 net) wells on our East Texas resource play acreage, one gross (0.4 net) well on our South Texas resource play acreage, and 4 gross (2.4 net) wells in Liberty County. The actual number of wells drilled and the amount of our 2010 capital expenditures will depend on market conditions, availability of capital and drilling and production results.

Inflation and Changes in Prices

While the general level of inflation affects certain costs associated with the petroleum industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have, a material effect on our operations; however, we cannot predict these fluctuations.

The following table indicates the average quarterly natural gas, crude oil and natural gas liquids prices realized over the last three years. Average prices per Mcf equivalent, computed by converting crude oil and natural gas liquids production to natural gas equivalents at the rate of 6 *Mcf* per barrel, indicate the composite impact of changes in natural gas, crude oil and natural gas liquids prices.

	Average Prices[1]			
	Natural Gas (per Mcf)	Crude Oil (per Bbl)	Natural Gas Liquids [2] (per Bbl)	Per Equivalent Mcf
2009				
First	$ 6.71	$ 77.18	$ 22.51	$ 7.08
Second	6.71	80.62	27.37	7.29
Third	6.92	87.85	31.50	7.60
Fourth	7.20	92.19	42.87	8.15
2008				
First	$ 8.39	$ 78.62	$ 57.18	$ 9.39
Second	10.23	95.52	55.73	10.94
Third	9.68	92.54	63.49	10.67
Fourth	7.20	68.42	28.84	7.52
2007				
First	$ 7.07	$ 60.28	$ —	$ 8.33
Second	7.64	62.66	43.29	8.09
Third	7.60	66.47	45.17	8.18
Fourth	7.28	69.41	55.19	8.42

(1) Average sales price are shown net of the settled amounts of our natural gas and crude oil hedge contracts.
(2) Natural gas liquids became a significant addition to our reserves since the acquisition of the STGC Properties in May 2007.

Off Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance our liquidity and capital resources position or for any other purpose.

ITEM 8. Financial Statements and Supplementary Data

Information with respect to this Item 8 is contained in our financial statements beginning on Page F-1 of this Annual Report on Form 10-K and are incorporated herein by reference.

ITEM 9. Changes In and Disagreements with Accountants and Accounting and Financial Disclosure

None

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures

Our President and Chief Executive Officer and our Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by this Form 10-K, that our disclosure controls and procedures, as defined under Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, are effective to ensure that information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that our disclosure controls and procedures are effective to ensure that information we are required to disclose in such reports is accumulated and communicated to management, including our President and Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

During the three months ended December 31, 2009, there has been no change to our internal controls over financial reporting that materially affected, or is reasonably likely to materially affect, these controls.

Management's Report on Internal Control over Financial Reporting

Management's annual report on internal control over financial reporting as of December 31, 2009 is in "Item 8. Financial Statements and Supplementary Data" in Part II of this Annual Report on Form 10-K and is incorporated herein by reference.

This Annual Report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the SEC that permit us to provide only management's report in this Annual Report.

ITEM 9B. Other Information

None

PART III

ITEM 10. Directors and Executive Officers of the Registrant

Information regarding directors and executive officers of the registrant is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2009.

ITEM 11. Executive Compensation

Information regarding executive compensation is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2009.

ITEM 12. Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information regarding security ownership of certain beneficial owners and management and related stockholder matters is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2009.

ITEM 13. Certain Relationships and Related Transactions

Information regarding certain relationships and related transactions is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2009.

ITEM 14. Principal Accountant Fees and Services

Information regarding principal accountant fees and services is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2009.

GLOSSARY OF SELECTED TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this Annual Report.

2D seismic or *3D seismic*. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

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

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBbls. million barrels of crude oil or other liquid hydrocarbons.

MMBtu. million British Thermal Units.

MMcf. million cubic feet of natural gas.

MMcfe. million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d. Mmcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

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

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

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(4) of Regulation S-X, which defines proved undeveloped reserves as reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

Trucking. The provision of trucks to move our drilling rigs from one well location to another and to deliver water and equipment to the field.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules.

The following documents are filed as part of this Report:

(1) Financial Statements:

Report of Management
Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets at December 31, 2009 and 2008
Consolidated Statements of Operations for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007
Notes to Consolidated Financial Statements

(2) Financial Statement Schedule:

Schedule II - Valuation and Qualifying Accounts

(3) Exhibits:

Number	Description
2.1	Membership Interest Purchase and Sale Agreement, dated May 8, 2007, by and among EXCO Resources, Inc., Southern G Holdings, LLC, Crimson Exploration Inc. and Crimson Exploration Operating Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed May 15, 2007)
2.2	Purchase and Sale Agreement, dated April 28, 2008, by and among Smith Production, Inc. and Crimson Exploration Inc. (incorporated by reference to Exhibit 2.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008)
3.1	Certificate of Incorporation of the Registrant (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed July 5, 2005)
3.2	Certificate of Designation, Preferences and Rights of Series D Preferred Stock (incorporated by reference to Exhibit 3.3 to the Company's Current Report on Form 8-K filed July 5, 2005)
3.3	Certificate of Designation, Preferences and Rights of Series E Cumulative Convertible Preferred Stock (incorporated by reference to Exhibit 3.4 to the Company's Current Report on Form 8-K filed July 5, 2005)
3.4	Certificate of Designation, Preferences and Rights of Series G Convertible Preferred Stock (incorporated by reference to Exhibit 3.5 to the Company's Current Report on Form 8-K filed July 5, 2005)
3.5	Certificate of Designation, Preferences and Rights of Series H Convertible Preferred Stock (incorporated by reference to Exhibit 3.6 to the Company's Current Report on Form 8-K filed July 5, 2005)
3.6	Bylaws of the Crimson Exploration Inc. (incorporated by reference to Exhibit 3.7 to the Company's Current Report on Form 8-K filed July 5, 2005)
3.7	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Appendix A to the Company's Definitive Information Statement on Schedule 14C filed August 18, 2006)

ITEM 15. Exhibits and Financial Statement Schedules. (continued)

Number	Description
3.8	Certificate of Amendment to Certificate of Designation, Preferences and Rights of Series G Convertible Preferred Stock of Crimson Exploration Inc., dated December 8, 2009 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed December 10, 2009)
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 3.7 to the Company's Current Report on Form 8-K filed July 5, 2005)
4.2	Letter Agreement by and among GulfWest Energy Inc., a Texas corporation, GulfWest Oil & Gas Company and the investors listed on the signature page thereof, dated April 22, 2004 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 10, 2004)
4.3	Shareholders Rights Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(e) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
4.4	Omnibus and Release Agreement among GulfWest Energy Inc., OCM GW Holdings, LLC and those signatories set forth on the signature page thereto, dated as of February 28, 2005 (incorporated by reference to Exhibit 99(f) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
4.5	Waiver, Consent and First Amendment to the Shareholders Rights Agreement, dated as of December 7, 2009, between Crimson Exploration Inc. and OCM GW Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed December 10, 2009)
4.6	Termination Agreement, dated as of December 7, 2009, between Crimson Exploration Inc. and OCM GW Holdings, LLC (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed December 10, 2009)
#10.1	Amended and Restated Employment Agreement between Allan D. Keel and Crimson Exploration Inc., dated December 30, 2008 (incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.2	Amended and Restated Employment Agreement between E. Joseph Grady and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.3	GulfWest Energy Inc. 2004 Stock Option Incentive Plan. (incorporated by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004)
#10.4	GulfWest Energy Inc. 2005 Stock Option Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004)
#10.5	Form of GulfWest Energy Inc. 2005 Stock Incentive Plan Stock Option Agreement (incorporated by reference to Exhibit 10.6 of Amendment No. 1 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005)

ITEM 15. Exhibits and Financial Statement Schedules. (continued)

Number	Description
#10.6	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on July 21, 2005)
10.7	Series G Subscription Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(a) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
10.8	Series A Subscription Agreement between GulfWest Oil & Gas Company and OCW GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(b) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
10.9	Oil and Gas Property Acquisition, Exploration and Development Agreement with Summit Investment Group-Texas, L.L.C. effective December 1, 2001 (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement No. 333-116048 on Form S-1)
#10.10	Amended and Restated Employment Agreement between Tracy Price and Crimson Exploration Inc., dated December 30, 2008 (incorporated by reference to Exhibit 10.11 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2009)
#10.11	Amended and Restated Employment Agreement between Tommy Atkins and Crimson Exploration Inc., dated December 29, 2008 (incorporated by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.12	Amended and Restated Employment Agreement between Jay S. Mengle and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.13	Summary terms of Director Compensation Plan (incorporated by reference to Exhibit 10.14 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.14	Form of director and officer restricted stock grant (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on July 21, 2005)
10.15	Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto. (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed May 15, 2007)
#10.16	Form of executive officer restricted stock grant for grants outside the 2005 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed August 7, 2007)
10.17	Amendment No. 1, dated as of June 5, 2007, to the Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 8, 2007)

ITEM 15. Exhibits and Financial Statement Schedules. (continued)

Number	Description
10.18	Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., as borrower, Wells Fargo Bank, National Association, as agent, Wells Fargo Bank, National Association and The Royal Bank of Scotland, plc, as co-lead arrangers and joint bookrunners, and each lender from time to time party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 6, 2007)
#10.19	Employment Agreement between Rusty Shepherd and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.20	Crimson Exploration Inc. 2005 Stock Incentive Plan, Amended and Restated Effective as of August 15, 2008 (incorporated by reference to Exhibit A of the Company's Information Statement on Schedule 14C filed September 25, 2008)
#10.21	Form of Restricted Stock Award used in connection with option exchange and in connection with the Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed September 11, 2008)
#10.22	Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
#10.23	Cash Incentive Bonus Plan (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
#10.24	Long Term Performance Plan Form of Restricted Stock Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.25	Long Term Incentive Performance Plan Form of Stock Option Agreement for Employees (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.26	Long Term Incentive Performance Plan Form of Restricted Stock Award Agreement for Executive Officers (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.27	Long Term Incentive Performance Plan Form of Restricted Stock Option Agreement for Executive Officers (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
10.28	Amendment No. 2, dated as of May 13, 2009, to the Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
10.29	Amendment No. 3 and Waiver, dated as of November 6, 2009, to the Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., Crimson Exploration Operating, Inc. and the lender parties thereto (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K for the quarter filed November 13, 2009)

ITEM 15. Exhibits and Financial Statement Schedules. (continued)

Number	Description
10.30	First Amendment, dated as of July 31, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, by and among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 5, 2009)
10.31	Second Amendment, dated as of November 6, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 13, 2009)
10.32	Third Amendment and Limited Waiver, dated as of November 6, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed November 13, 2009)
10.33	Promissory Note, dated November 6, 2009, made by Crimson Exploration Inc. to Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed November 13, 2009)
10.34	Subordinated Promissory Note, dated November 6, 2009, made by Crimson Exploration Inc. to OCM GW Holdings, LLC (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed November 13, 2009)
10.35	Fourth Amendment, dated as of December 7, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 10, 2009)
*21.1	Significant Subsidiaries of the Registrant
*23.1	Consent of Grant Thornton LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
25.1	Power of Attorney (included on signature page of this Annual Report)
*31.1	Certification of Chief Executive Officer pursuant to Exchange Rule 13a-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer pursuant to Exchange Rule 13a-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*99.1	Estimate of Reserves and Future Revenue to the Crimson Exploration Inc. Interest in Certain Oil and Gas Properties located in the United States and in the Gulf of Mexico as of December 31, 2009 provided by Netherland, Sewell and Associates, Inc.

* filed herewith
# management contract or compensatory plan or arrangement

S I G N A T U R E S

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CRIMSON EXPLORATION INC.

Date: March 16, 2010

By /s/ Allan D. Keel
Allan D. Keel, President

POWER OF ATTORNEY

Know all men by these presents, that the undersigned constitutes and appoints Allan D. Keel as his true and lawful attorney-in-fact and agent, with full power of substitution, for him and in his name, place, and stead, in any and all capacities to sign any and all amendments or supplements to this Annual Report on Form 10-K, and to file the same, and with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons, on behalf of the registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Allan D. Keel Allan D. Keel	President, Chief Executive Officer and Director	March 16, 2010
/s/ E. Joseph Grady E. Joseph Grady	Senior Vice President and Chief Financial Officer	March 16, 2010
/s/ Terence Lynch Terence Lynch	Corporate Controller and Chief Accounting Officer	March 16, 2010
/s/ B. James Ford B. James Ford	Director	March 16, 2010
/s/ Lon McCain Lon McCain	Director	March 16, 2010
/s/ Lee B. Backsen Lee B. Backsen	Director	March 16, 2010
/s/ Adam C. Pierce Adam C. Pierce	Director	March 16, 2010
/s/ Cassidy J. Traub Cassidy J. Traub	Director	March 16, 2010

CRIMSON EXPLORATION INC.

FINANCIAL REPORT

DECEMBER 31, 2009

C O N T E N T S

All other financial statement schedules have been omitted because they are either inapplicable or the information required is included in the financial statements or the notes thereto.

REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Company is responsible for the preparation and integrity of the consolidated financial statements appearing in the annual report on form 10-K. The financial statements were prepared in conformity with accounting principles generally accepted in the United States and include amounts that are based on management's best estimates and judgments.

Management of the Company is responsible for establishing and maintaining effective internal control over financial reporting as such term is defined in Rule 13a-15(f) under the Securities Exchange Act of 1934 (*"Exchange Act"*). The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements. Our internal control over financial reporting is supported by a program of appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written code of business conduct adopted by our Company's board of directors, applicable to all Company directors and all officers and employees of our Company and subsidiaries.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control —Integrated Framework*. Based on our assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2009.

/s/ Allan D. Keel
Allan D. Keel
President and Chief Executive Officer

/s/ E. Joseph Grady
E. Joseph Grady
Senior Vice President and Chief Financial Officer

/s/ Terence Lynch
Terence Lynch
Corporate Controller and Chief Accounting Officer

Houston, Texas
MARCH 16, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Crimson Exploration Inc.

We have audited the accompanying consolidated balance sheets of Crimson Exploration Inc. and subsidiaries (collectively, the “Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crimson Exploration Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil & gas reserve estimation and disclosure requirements as of December 31, 2009.

/s/ GRANT THORNTON LLP

Houston, Texas

March 16, 2010

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS

	December 31, 2009	December 31, 2008
CURRENT ASSETS		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net of allowance	14,773,246	21,078,815
Prepaid expenses	—	77,293
Derivative instruments	9,937,697	25,191,445
Total current assets	24,710,943	46,347,553
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method of accounting)	559,565,531	584,093,885
Other property and equipment	3,679,515	3,282,088
Accumulated depreciation, depletion and amortization	(170,117,319)	(138,220,237)
Total property and equipment, net	393,127,727	449,155,736
NONCURRENT ASSETS		
Deposits	104,697	104,697
Debt issuance cost	4,347,298	2,890,094
Deferred charges	—	1,324,907
Derivative instruments	2,513,369	11,722,802
Total noncurrent assets	6,965,364	16,042,500
TOTAL ASSETS	$ 424,804,034	$ 511,545,789

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2009	December 31, 2008
CURRENT LIABILITIES		
Current portion of long-term debt	$ 19,014	$ 90,368
Accounts payable	20,263,343	47,776,858
Income tax payable	250,931	546,944
Accrued liabilities	8,852,310	24,369,060
Asset retirement obligations	330,287	1,659,371
Derivative instruments	872,849	1,265,801
Deferred tax liability, net	2,897,300	8,331,208
Total current liabilities	33,486,034	84,039,610
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	192,749,751	276,640,426
Asset retirement obligations	9,372,366	11,409,171
Derivative instruments	1,284,105	1,491,755
Deferred tax liability, net	4,471,023	15,609,315
Other noncurrent liabilities	709,867	732,709
Total noncurrent liabilities	208,587,112	305,883,376
Total liabilities	242,073,146	389,922,986
COMMITMENTS AND CONTINGENCIES (see Note 11)		
STOCKHOLDERS' EQUITY		
Preferred stock (see Note 12)	—	826
Common stock (Par value $0.001; 200,000,000 shares authorized; 38,516,658 and 5,787,287 shares issued and outstanding as of December 31, 2009 and 2008, respectively)	38,578	5,808
Additional paid-in capital	209,738,513	95,676,875
Retained earnings (deficit)	(26,661,891)	26,189,888
Treasury stock (At cost, 61,546 and 20,625 shares as of December 31, 2009 and 2008, respectively)	(384,312)	(250,594)
Total stockholders' equity	182,730,888	121,622,803
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 424,804,034	$ 511,545,789

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2009	2008	2007
OPERATING REVENUES			
Natural gas sales	$ 71,494,889	$ 116,414,956	$ 67,867,605
Crude oil sales	27,283,772	41,860,385	27,021,296
Natural gas liquids sales	13,024,103	27,404,774	14,272,712
Operating overhead and other income	644,882	1,088,158	381,595
Total operating revenues	112,447,646	186,768,273	109,543,208
OPERATING EXPENSES			
Lease operating expenses	17,358,670	20,824,629	12,033,963
Production and ad valorem taxes	7,131,400	16,266,493	11,701,908
Exploration expenses	3,786,270	9,965,372	3,174,415
Depreciation, depletion and amortization	53,294,809	50,466,966	30,796,487
Impairment and abandonment of proved properties	5,658,898	35,953,586	4,362,186
General and administrative	18,757,981	22,405,639	14,541,780
Loss (gain) on sale of assets	6,847,454	(15,209,706)	(683,830)
Total operating expenses	112,835,482	140,672,979	75,926,909
INCOME (LOSS) FROM OPERATIONS	(387,836)	46,095,294	33,616,299
OTHER INCOME (EXPENSE)			
Interest expense, net of amount capitalized	(23,172,082)	(21,108,603)	(14,949,358)
Other financing costs	(3,341,854)	(1,501,627)	(1,321,661)
Unrealized (loss) gain on derivative instruments	(23,862,580)	49,408,961	(18,186,158)
Total other income (expense)	(50,376,516)	26,798,731	(34,457,177)
INCOME (LOSS) BEFORE INCOME TAXES	(50,764,352)	72,894,025	(840,878)
Income Tax Benefit (Expense)	16,694,362	(26,690,807)	410,361
NET INCOME (LOSS)	(34,069,990)	46,203,218	(430,517)
Dividends on Preferred Stock (Paid 2009-$18,781,789; 2008-$153,378; 2007-$702,948)	(4,522,645)	(4,234,050)	(4,453,872)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (38,592,635)	$ 41,969,168	$ (4,884,389)
NET INCOME (LOSS) PER SHARE			
Basic	$ (4.91)	$ 7.81	$ (1.13)
Diluted	$ (4.91)	$ 4.46	$ (1.13)
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	7,861,054	5,371,377	4,330,282
Diluted	7,861,054	10,360,348	4,330,282

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 and 2007

	NUMBER OF SHARES							
	PREFERRED STOCK	COMMON STOCK	PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS (DEFICIT)	TREASURY STOCK	TOTAL STOCKHOLDERS' EQUITY
BALANCE, DECEMBER 31, 2006	103,220	3,333,602	$ 1,032	$ 3,334	$ 79,693,736	$ (18,372,319)	$ —	$ 61,325,783
Current year net loss	—	—	—	—	—	(430,517)	—	(430,517)
Cumulative effect of change in accounting principle	—	—	—	—	—	(354,168)	—	(354,168)
Share-based compensation	—	252,818	—	253	4,531,930	—	—	4,532,183
Stock options and warrants exercised	—	4,000	—	5	4,795	—	—	4,800
Preferred H converted	(3,020)	431,430	(30)	430	(400)	—	—	—
Preferred E converted	(9,000)	225,000	(90)	225	(135)	—	—	—
Preferred D converted	(8,000)	50,000	(80)	50	30	—	—	—
Acquisition of oil and gas leases	—	750,000	—	750	4,574,250	—	—	4,575,000
Dividends paid on preferred stock	—	81,087	—	81	702,867	(702,948)	—	—
BALANCE, DECEMBER 31, 2007	83,200	5,127,937	832	5,128	89,507,073	(19,859,952)	—	69,653,081
Current year net income	—	—	—	—	—	46,203,218	—	46,203,218
Share-based compensation	—	547,168	—	547	5,670,051	—	—	5,670,598
Stock options exercised	—	75,000	—	75	346,425	—	—	346,500
Preferred G converted	(500)	27,778	(5)	28	(23)	—	—	—
Preferred H converted	(100)	14,286	(1)	14	(13)	—	—	—
Dividends paid on preferred stock	—	15,743	—	16	153,362	(153,378)	—	—
Treasury stock	—	(20,625)	—	—	—	—	(250,594)	(250,594)
BALANCE, DECEMBER 31, 2008	82,600	5,787,287	826	5,808	95,676,875	26,189,888	(250,594)	121,622,803
Current year net loss	—		—	—	—	(34,069,990)	—	(34,069,990)
Share-based compensation	—	661,156	—	661	2,400,231	—	—	2,400,892
Preferred G converted	(80,500)	8,050,000	(805)	8,050	(7,245)	—	—	—
Preferred H converted	(2,100)	300,001	(21)	300	(279)	—	—	—
Dividends paid on preferred stock	—	3,759,135	—	3,759	18,778,030	(18,781,789)	—	—
Common stock issuance	—	20,000,000	—	20,000	92,890,901	—	—	92,910,901
Treasury stock	—	(40,921)	—	—	—	—	(133,718)	(133,718)
BALANCE, DECEMBER 31, 2009	—	38,516,658	$ —	$ 38,578	$ 209,738,513	$ (26,661,891)	$ (384,312)	$ 182,730,888

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (34,069,990)	$ 46,203,218	$ (430,517)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	53,294,809	50,466,966	30,796,487
Asset retirement obligations	(375,149)	(546,840)	(268,445)
Stock compensation expense	2,400,892	5,434,992	4,738,125
Amortization of debt issuance cost	3,156,687	1,091,929	1,059,033
Discount on notes payable	10,794	—	—
Deferred charges	1,324,907	75,093	(1,400,000)
Deferred income taxes	(16,572,200)	25,563,734	(410,361)
Dry holes, abandoned property, impaired assets	6,721,216	43,309,365	5,710,125
Loss (gain) on sale of assets	6,847,454	(15,209,706)	(683,830)
Unrealized loss (gain) on derivative instruments	23,862,580	(49,408,961)	18,186,158
Bad debt expense	239,676	—	96,904
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable – trade, net	6,065,890	8,973,958	(22,648,152)
Decrease (increase) in prepaid expenses	77,293	153,577	(5,566)
(Decrease) increase in accounts payable and accrued liabilities	(43,329,186)	27,661,406	34,871,687
Net cash provided by operating activities	9,655,673	143,768,731	69,611,648
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sale of assets	7,553,480	34,923,332	756,650
Acquisition of oil and gas properties	493,532	(58,481,721)	(253,434,220)
Capital expenditures	(21,893,154)	(141,794,612)	(59,048,764)
Deposits	—	(10,106)	(45,089)
Net cash used in investing activities	(13,846,142)	(165,363,107)	(311,771,423)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of common stock	92,910,901	346,500	4,800
Purchase of treasury stock	(133,718)	(250,594)	—
Payments on debt	(196,079,649)	(132,393,063)	(68,571,595)
Proceeds from debt	110,367,869	149,009,022	320,177,233
Debt issuance expenditures	(2,874,934)	—	(4,591,473)
Net cash provided by financing activities	4,190,469	16,711,865	247,018,965
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	—	(4,882,511)	4,859,190
CASH AND CASH EQUIVALENTS, Beginning of year	—	4,882,511	23,321
CASH AND CASH EQUIVALENTS, End of year	$ —	$ —	$ 4,882,511
Cash paid for interest, net of capitalized interest	$ 20,092,443	$ 22,484,711	$ 14,914,194
Cash paid for income taxes	$ 173,851	$ 580,129	$ —

The Notes to Consolidated Financial Statements are an integral part of these statements.

1. Organization

Crimson Exploration Inc., together with its subsidiaries, (*"Crimson"*, *"we"*, *"our"*, *"us"*) is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of 824 gross drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91% (excluding one well which has not yet been completed).

As of December 31, 2009, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 97.5 Bcfe, net of 7.6 Bcfe of reserves sold in December 2009, consisting of 69.9 Bcf of natural gas and 4.6 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2009, 72% of our proved reserves were natural gas, 70% were proved developed and 86% were attributed to wells and properties operated by us. During the last three years, we have grown proved reserves from 46.4 Bcfe to 97.5 Bcfe. In addition, our average daily production increased from 7.3 MMcfe/d for the twelve months ended December 31, 2006 to 40.9 MMcfe/d for the twelve months ended December 31, 2009.

2. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States. Our operations are considered to fall within a single industry segment, which is the acquisition, development, exploitation and production of natural gas and crude oil properties in the United States. All significant intercompany balances and transactions have been eliminated upon consolidation. Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation. Significant policies are discussed below.

Cash and Cash Equivalents

We consider all highly liquid investment instruments purchased with remaining maturities of three months or less to be cash equivalents for purposes of the consolidated statements of cash flows and other statements. We maintain cash on deposit in non-interest bearing accounts, which, at times, exceed federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

Use of Estimates in the Preparation of Financial Statements

The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates included in the consolidated financial statements are: (1) natural gas, crude oil and natural gas liquids revenues and reserves; (2) depreciation, depletion and amortization; (3) valuation allowances associated with income taxes and accounts receivables; (4) accrued assets and liabilities; (5) stock-based compensation; (6) asset retirement obligations and (7) valuation of derivative instruments. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates. Actual results could differ from those estimates.

Oil and Gas Properties

We use the successful efforts method of accounting for natural gas and crude oil producing activities. Costs to acquire mineral interests in natural gas and crude oil properties are capitalized. Costs to drill and develop development wells and costs to drill and develop exploratory wells that find proved reserves are also capitalized.

Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed (except those costs used to determine a drill site location).

Capitalized costs of producing natural gas and crude oil properties and support equipment, net of estimated salvage values, are depleted by the unit-of-production method.

Oil and Gas Reserves

The estimates of proved natural gas, crude oil and natural gas liquids reserves utilized in the preparation of the financial statements are estimated in accordance with guidelines established by the Securities and Exchange Commission (*"SEC"*) and the Financial Accounting Standards Board (*"FASB"*), which require that reserve estimates be prepared under existing economic and operating conditions using a 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements.

We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to deplete capitalized natural gas, crude oil and natural gas liquids costs on the unit of production method, based upon these reserve estimates. It is possible that, because of changes in market conditions or the inherent imprecision of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of natural gas, crude oil and natural gas liquids reserves, the remaining estimated lives of the natural gas and crude oil properties, or any combination of the above may be increased or reduced. See Note 17 – "Oil and Gas Reserves (unaudited)" for further information.

Capitalized Interest

Interest is capitalized as part of the historical cost of acquiring assets. Natural gas and crude oil investments in exploration and development activities that are in progress qualify for interest capitalization. Capitalized interest is calculated by multiplying the weighted-average interest rate on debt used to finance the asset by the amount of qualifying costs. Capitalized interest cannot exceed gross interest expense. Any associated capitalized interest is transferred to the appropriate asset and is depleted by the unit of production method. Capitalized interest was approximately $25,000, $0.9 million and $1.3 million in 2009, 2008 and 2007 respectively.

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our natural gas and crude oil wells and associated pipelines and equipment. The liability and the associated increase in the related long-lived asset are recorded in the period in which the related assets are placed in service or acquired. The liability is accreted to its present value each period and the capitalized cost is depleted over the useful life of the related asset. The accretion expense is included in depreciation, depletion and amortization (*"DD&A"*) expense.

The estimated liability is based on historical experience in plugging and abandoning wells. The estimated remaining lives of the wells is based on reserve life estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate or changes in the remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we recognize a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs. This gain or loss on abandonment is included in exploration expenses.

Impairments

Impairments, measured using fair market value, are recognized whenever events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable and the future undiscounted cash flows attributable to the asset are less than its carrying value. Non-cash impairment expense was approximately $3.2 million, $36.0 million and $4.4 million in 2009, 2008 and 2007, respectively. See Note 6 — "Impairment and Abandonment of Proved Properties" for further information.

Revenue Recognition and Oil and Gas Imbalances

We follow the "sales" method of accounting for natural gas, crude oil and natural gas liquids revenues. Under this method, we recognize revenues on production as it is taken and delivered to its purchasers. The volumes sold may be more or less than the volumes we are entitled to based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. Our crude oil and natural gas imbalances are not significant.

Trade Accounts Receivable

We grant credit to creditworthy independent and major natural gas and crude oil marketing companies for the sale of natural gas, crude oil and natural gas liquids. In addition, we grant credit to our oil and gas working interest partners. Receivables from our working interest partners are generally secured by the underlying ownership interests in the properties.

The accounts receivable ("*A/R*") balance at year-end primarily relates to A/R Trade (net of allowance for doubtful accounts), A/R joint interest billing (net of legal suspense/prepayments from partners), Accrued revenue (two months for operated properties, three months for non-operated properties), and A/R Other. Accrued revenue is recorded net to our interest (excludes outside interest holders).

The allowance for doubtful accounts is recognized by management based upon a review of specific customer balances, historical losses and general economic conditions. The allowance for doubtful accounts at December 31, 2009 and 2008 was $411,324 and $215,015, respectively.

Fair Value Measurements

Accounting guidance establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. We incorporate a credit risk assumption into the measurement of certain assets and liabilities. See Note 5 – "Fair Value Measurements" for further information.

Debt Issuance Costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt using the effective interest method.

Earnings (Loss) Per Share

Basic earnings (loss) per share are based on the weighted-average number of outstanding common shares. Diluted earnings (loss) per-share are based on the weighted-average number of outstanding common shares and the effect of all potentially diluted common shares. See Note 14 – "Income (Loss) Per Common Share" for further information.

Share-Based Compensation

We measure the grant date fair value of stock options and other stock-based compensation issued to employees and expense the fair value over the requisite service period of the award. It is our policy to issue new shares for any options exercised. We use the Black-Scholes option pricing model to measure the fair value of stock options.

We estimate forfeitures in calculating the expense related to stock-based compensation as opposed to recognizing forfeitures as they occur. All of our unvested options are held by our executive officers, employees and directors. See Note 13 – “Share-Based Compensation” for further information.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the applicable tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax returns or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was enacted.

We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset is reduced by a valuation allowance. In addition we routinely assess uncertain tax positions, and accrue for tax positions that are not more-likely-than-not to be sustained upon examination by taxing authorities. See Note 15 — "Income Taxes" for further information.

Supplementary Disclosures of the Consolidated Statements of Cash Flows

The following table sets forth non-cash investing and financing activities for the three years ended December 31,:

	2009	2008	2007
Non-cash stock issuance for oil and gas properties	$ —	$ —	$ 4,575,000
Liabilities released on property dispositions	5,309,005	—	—
Conversion of preferred stock dividends	(18,753,649)	(63,387)	—
Promissory note, net of discount [1]	(1,749,751)	—	—

(1) See Note 10 “Debt —Promissory Note” for further information.

New Accounting Standards Adopted

Accounting Standards Codification — On July 1, 2009, the Financial Accounting Standards Board (“*FASB*”) instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The FASB *Accounting Standards Codification*™ (“*ASC*”) is now the single authoritative source for GAAP. Although the implementation of ASC had no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

FASB Accounting Standards Update (*"ASU"*) 2010-03 was issued on January 6, 2010, and aligns the current oil and natural gas reserve estimation and disclosure requirements of ASC 932 with those in the *SEC Final Rule Modernization of Oil and Gas Reporting* issued December 31, 2008. The rules only apply prospectively as a change in estimate. The most significant amendments to the reserve and disclosure requirements include the following:

- Commodity Prices—Economic producibility of reserves and discounted cash flows will be based on an unweighted arithmetic average of the first day of the month commodity price during the 12-month period ending on the balance sheet date unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves—Probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved Undeveloped Reserve Guidelines—Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.
- Reserve Estimation Using New Technologies—Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserve Personnel and Estimation Process—Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Disclosure by Geographic Area—Reserves in foreign countries or continents must be presented separately if they represent more than 15% of our total oil and natural gas proved reserves.
- Non-Traditional Resources—The definition of oil and natural gas producing activities will expand and focus on the marketable product rather than the method of extraction.

ASU 2010-03 is effective for entities with annual reporting periods ending on or after December 31, 2009. We adopted both the FASB and the SEC rules as of December 31, 2009. Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of the new 12-month average pricing rules at December 31, 2009 resulted in proved reserves of approximately 97,489 MMcfe and PV-10 of $176.4 million. Use of the old year-end pricing rules would have resulted in proved reserves of approximately 114,633 MMcfe at December 31, 2009 and PV-10 of $305.0 million.

Adoption of ASU 2009-05 — In August 2009, the Financial Accounting Standards Board ("*FASB*") issued Accounting Standards Update ("*ASU*") No. 2009-05, *Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value.* ASU 2009-05 provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. We adopted ASU No. 2009-05 (FASB ASC 820-10) as of September 30, 2009. The adoption of this statement did not have an impact on our financial position or results of operations.

Interim Disclosures about Fair Value of Financial Instrument — We adopted FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments", which is now incorporated into ASC Topic No. 825 ("*ASC 825*") as of June 30, 2009. This statement increases the frequency of fair value disclosures to a quarterly instead of annual basis. The guidance relates to fair value disclosures for any financial instruments that are not currently reflected on the balance sheet at fair value. The adoption of this statement did not have a material impact on our financial position or results of operations.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly — We adopted the FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" which is now incorporated into ASC Topic No. 820 ("*ASC 820*") as of June 30, 2009. ASC 820 provides guidelines for a broad interpretation of when to apply market-based fair value measures. It reaffirms management's need to use judgment to determine when a market that was once active has become inactive and in determining fair values in markets that are no longer active.

Disclosure about Derivative Instruments and Hedging Activities — We adopted FASB Statement No. 161, "Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" which is now incorporated into ASC Topic No. 815 ("*ASC 815*") as of January 1, 2009. ASC 815 amends and expands the disclosure requirements for derivative instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for; and (iii) how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. See Note 7 – "Derivative Instruments" for these additional disclosures. The adoption of this statement did not have an impact on our financial position or results of operations.

Business Combinations — We adopted SFAS No. 141 (Revised 2007) "Business Combinations" which is now incorporated into ASC Topic No. 805 ("*ASC 805*") as of January 1, 2009. The revision broadens the definition of a business combination to include all transactions or other events in which control of one or more businesses is obtained. Further, this statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. The adoption of this statement has not had an impact on our financial position or results of operations, because we have not yet had any business combinations in 2009.

Effective Date of FASB Statement No. 157 - We also adopted FSP SFAS 157-2, "Effective Date of FASB Statement No. 157", which is also now incorporated into ASC Topic No. 820 as of January 1, 2009. The effective date was deferred for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually) to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. See Note 5 – "Fair Value Measurements" for additional disclosures. The adoption of this statement did not have a material impact on our financial position or results of operations.

New Accounting Standards Not Yet Adopted

Accounting Standards Update ("ASU") 2010-06 — In January 2010, the Financial Accounting Standards Board ("*FASB*") issued ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements.* ASU 2010-06 requires reporting entities to provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy established by FASB ASC 820. The guidance is effective for any fiscal year that begins after December 15, 2010 and should be used for quarterly and annual filings. We will adopt the provisions of ASU 2010-06 on January 1, 2010 and do not anticipate that this standard will have a material impact on our financial position, results of operations or cash flows.

3. Oil and Gas Properties

The following tables set forth certain information with respect to our oil and gas producing activities (all within the United States) for the periods presented:

Capitalized Costs Relating to Oil and Gas Producing Activities:

	2009	**2008**
Unproved oil and gas properties	$ 68,614,143	$ 68,278,373
Proved oil and gas properties	461,679,614	489,069,881
Wells and related equipment and facilities	29,271,774	26,745,631
	559,565,531	584,093,885
Less accumulated depreciation, depletion and amortization	(168,431,710)	(136,973,810)
Net capitalized costs	$ 391,133,821	$ 447,120,075

The following table sets forth the composition of exploration expenses:

	2009	2008	2007
Dry holes	$ —	$ —	$ 605,561 (1)
Lease rental expense	224,258	172,384	242,103
Geological and geophysical	1,733,426	1,692,102	1,430,046
Settled asset retirement obligations	766,269	745,107	69,325
Abandoned property - unproved	1,062,317	7,355,779 (2)	827,380
	$ 3,786,270	$ 9,965,372	$ 3,174,415

(1) Mustang Island was reclassified from impairment to a dry hole.
(2) In November 2008, we released an undeveloped leasehold position that we acquired from Core Natural Resources in Culberson County, Texas in 2006, and recorded a $7.1 million exploration expense.

Costs Incurred in Oil and Gas Producing Activities:

	2009	2008	2007
Property Acquisitions			
Proved	$ (493,532)	$ 60,765,315	$ 238,036,360
Unproved	1,833,949	57,203,337	30,407,525
Development Costs	11,398,237	86,685,192	30,814,788
Exploration Costs	11,815,450	2,520,389	13,405,017
	$ 24,554,104	$ 207,174,233	$ 312,663,690

These costs include oil and gas property acquisition, exploration and development activities regardless of whether the costs were capitalized or charged to expense, including lease rental expenses, geological and geophysical expenses and changes to the long-lived asset related to our asset retirement obligation.

The following table shows oil and gas property dispositions:

	2009	2008	2007
Oil and gas properties	$ 42,995,459	$ 21,765,688	$ —
Accumulated depreciation, depletion and amortization	(23,158,221)	(1,659,588)	—
Net oil and gas properties	$ 19,837,238	$ 20,106,100	$ —

The dispositions resulted in a net loss of $6.8 million and a net gain of $15.2 million for 2009 and 2008, respectively.

4. Acquisitions and Dispositions of Oil and Gas Properties

Southwest Louisiana Disposition

On December 28, 2009, we closed on a definitive agreement to sell operated and non-operated working interests in various producing wells, related production equipment and associated acreage primarily in Cameron, Calcasieu and Jefferson Davis parishes in Southwest Louisiana, with an effective date of October 1, 2009. The final total consideration paid by the buyer of $7.8 million was based on existing wells and undeveloped acreage owned by us at the time of the closing. The assets include substantially all of our Southwest Louisiana properties, representing approximately 7.6 Bcfe of proved reserves as of September 30, 2009, with average daily production of approximately 3.1 Mmcfe/d for the year ended December 31, 2009. The net proceeds of $7.3 million were primarily used to repay amounts outstanding under our senior revolving credit agreement. Our net book value of these assets sold was $18.8 million and the liabilities assumed by the buyer on these assets were $5.3 million, which resulted in a loss of $6.2 million. The agreement provides for up to an additional $2.4 million in gross proceeds for the sale of additional properties for which various consents are still being solicited. We have 180 days from the closing date to obtain these consents. The sale of these assets represents a strategic exit from operations in Southwest Louisiana.

East Texas Acreage Acquisition

In the second half of 2008 and 2009, we obtained natural gas and crude oil leases from mineral interest owners covering approximately 17,300 gross (12,000 net) acres in the natural gas resource play in East Texas specifically in San Augustine and Sabine Counties. We commenced our first well (the Kardell #1H), in which we owned a 52% working interest, in this play in late June 2009 and completed that well in October 2009. The well had a measured depth of approximately 18,350 feet and was a successful test of the Haynesville Shale formation. We plan to continue to pursue an active drilling program in this area for the next several years, targeting primarily the Haynesville Shale, Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations.

Smith Acquisition

In May 2008, we acquired four producing gas fields and undeveloped acreage in South Texas from Smith Production Inc. (*"Smith"*) for a purchase price of $65.0 million with an economic effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.4 million for the period between the effective date and the closing date, the cash consideration was approximately $57.6 million. The assets acquired consist of a 25% non-operated working interest in the Samano Field located in Starr and Hidalgo Counties, a 100% operated working interest in the North Bob West Field in Zapata County and 100% operated working interests in the Brushy Creek and Hope Fields in DeWitt County. We acquired an interest in over 16,000 gross acres with these fields, most of which is held by production. Production from the acquired assets was averaging approximately 7 MMcfe/d at closing, which resulted in a 13% increase in our then current net daily production.

The adjusted price for this acreage, with adjustment of the reserves for approximately one Bcfe of production for the interim operations between the effective date and closing, represents a purchase cost of $2.82 per Mcfe for approximately 21 Bcfe of proved reserves and $8,300 per Mcfe of current average daily production. We financed this acquisition with cash flows from operations, proceeds from the sale of assets and from borrowings available under our revolving credit agreement. For the year ended December 31, 2008, seven months of revenues and expenses, $11.7 million and $3.7 million, respectively, were included in our financial results of operations.

Barnett Shale Disposition

In January 2008, we and our operator-partner entered into a series of agreements to sell our interests in wells and undeveloped acreage in the Fort Worth Barnett Shale Play in Johnson and Tarrant Counties, Texas to another industry participant active in that area. We owned a 12.5% non-operated working interest in the assets being sold and had 1.5 Bcfe in proved reserves at December 31, 2007. The total consideration paid by the buyer was based on existing wells and undeveloped acreage owned by us and our partner at the time of the final closing. Our share of the consideration received was approximately $34.4 million. Proceeds received for our interest were primarily used to repay amounts outstanding under our revolving credit agreement and to help finance our acquisition of the properties from Smith. Our net book value of the assets sold was $18.8 million, which resulted in a gain of $15.6 million.

STGC Properties Acquisition

On May 8, 2007, we entered into a purchase agreement with EXCO and SGH (*"EXCO Purchase Agreement"*), pursuant to which we acquired, for $285.0 million in cash (excluding adjustments) and 750,000 shares of common stock, par value $0.001 per share (*"Common Stock"*) certain oil and natural gas properties and related assets in the STGC Properties held by SGH immediately before the closing of the acquisition. After considerations for typical closing adjustments, $229.0 million of the purchase price was allocated to proved properties and $28.6 million was allocated to unproved properties. The properties acquired include approximately 215 producing wells in over 30 fields. We have an average 65% working interest in the properties and operate more than 80% of the value acquired. The major producing fields acquired reside in Liberty and Lavaca counties of the Upper Texas Gulf Coast, Brooks County of South Texas and Calcasieu Parish of South Louisiana. The properties and related assets were acquired through the conveyance of 100% of the membership interests of SGH from EXCO to us. The consolidated statements of operations include the results of operations of the STGC Properties from May 2007 to present.

The unaudited pro forma results presented below for the year ended December 31, 2007 have been prepared to give effect to the STGC Properties acquisition described above on our results of operations as if it had been consummated on January 1, 2007. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or project our results of operations for any future date or period.

		For the Year Ended December 31, 2007
		(unaudited) (in thousands, except share amounts)
Pro forma:		
Operating revenues	$	154,068
Income from operations	$	56,647
Net income	$	9,305
Basic earnings per share	$	1.06
Diluted earnings per share	$	0.95

5. Fair Value Measurements

Certain of our assets and liabilities are reported at fair value in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values for each class of financial instruments:

Cash and Cash Equivalents, Accounts Receivable and Accounts Payable. The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Derivative Instruments. Our derivative instruments consist of variable to fixed price commodity swaps, costless collars and interest rate swaps. The fair value measurement of our unrealized natural gas, crude oil and interest rate swaps and collars were obtained from financial institutions and were evaluated for accuracy using our crude oil, natural gas and interest rate swap and collar agreements and future commodity and interest rate curves. Differences between management's calculation and that of the financial institution were evaluated for reasonableness. See Note 7 – "Derivative Instruments" for further information.

Impairments. We review oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs are typically not observable, we classify impairments of long-lived assets as a level 3 fair value measure.

Debt. The fair value of floating-rate debt is estimated to be equivalent to carrying amounts because the interest rates paid on such debt are set for periods of three months or less. See Note 10 – "Debt" for further information.

Fair value information for financial assets and liabilities that are measured at fair value each reporting period is as follows at December 31, 2009:

	Total Carrying Value	Fair Value Measurements Using Level 1	Level 2	Level 3
Derivatives				
Crude oil & natural gas swaps	$ (191,579)	$ —	$ (191,579)	$ —
Crude oil & natural gas collars	15,096,160	—	15,096,160	—
Interest rate swaps	(4,610,469)	—	(4,610,469)	—
Impairment				
Impairment of proved properties	3,183,255	—	—	3,183,255
	$ 13,477,367	$ —	$ 10,294,112	$ 3,183,255

FASB guidance established a fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.

6. Impairment and Abandonment of Proved Properties

In 2009 we recorded a non-cash impairment and abandonment of proved property expense of $5.7 million due in part to a $2.5 million abandonment expense related to our Alwan field in South Texas. The abandonment expense related to the expiration of leases in December 2009 that were not renewed. In December 2009, we also recorded an impairment expense of $1.5 million for a non-operated property in South Texas that was plugged by the operator due to the loss of behind pipe reserves. In December 2009, we also recorded a $1.1 million impairment expense on our non-operated West Cameron field in South Louisiana due to the watering out of certain zones.

In December 2008, we recorded a non-cash impairment expense of $10.2 million, primarily related to our Grand Lake Field in Southwest Louisiana. The impairment expense was a result of low commodity prices at year end and the underperformance of the Grand Lake Field. In September 2008, we recorded a non-cash impairment expense of $25.8 million related to our Madisonville Field in Central Texas. The Madisonville impairment relates primarily to the Rodessa formation within the Madisonville Field. Negative performance-related reserve revisions, including the abandonment of the Rodessa formation in the Johnston 2U well, triggered an evaluation of the Madisonville Field for impairment purposes. The high original cost of drilling and developing the field and the high cost of producing and processing sour gas, combined with lower commodity prices resulted in the recorded costs of this field exceeding the estimated future undiscounted cash flow of the reserves as of September 30, 2008.

7. Derivative Instruments

At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. We recorded net assets for derivative instruments of $10.3 million and $34.2 million at December 31, 2009 and 2008, respectively. As a result of these agreements, we recorded a non-cash unrealized loss, for unsettled contracts, of $23.9 million, a non-cash unrealized gain of $49.4 million and a non-cash unrealized loss of $18.2 million for the years ended December 31, 2009, 2008 and 2007, respectively. The estimated change in fair value of the derivatives is reported in Other Income (Expense) as unrealized gain (loss) on derivative instruments. The realized gain (loss) on derivative instruments is included in natural gas and crude oil sales for our commodity hedges and as an increase (decrease) in interest expense for our interest rate swaps.

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our natural gas and crude oil production, to reduce our sensitivity to volatile commodity prices, and with respect to portions of our debt, to reduce our sensitivity to volatile interest rates. None of our derivative instruments are designated as cash flow hedges. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to commodity price and interest rate fluctuations. However, derivative arrangements limit the benefit of increases in the prices of natural gas, crude oil and natural gas liquids sales and limit the benefit of decreases in interest rates. Moreover, our derivative arrangements apply only to a portion of our production and our debt and provide only partial protection against declines in commodity prices and increases in interest rates, respectively. Such arrangements may expose us to risk of financial loss in certain circumstances. We continuously reevaluate our hedging programs in light of changes in production, market conditions, commodity price forecasts, capital spending, interest rate forecasts and debt service requirements.

We use a mix of commodity swaps and costless collars and interest rate swaps to accomplish our hedging strategy. Derivative assets and liabilities with the same counterparty, subject to contractual terms which provide for net settlement, are reported on a net basis on our consolidated balance sheets. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges. These transactions are with counterparties in the financial services industry, and specifically with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparties. In addition, if any lender under our credit agreement is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender's commitment under our credit agreement. We believe our counterparty risk is low in part because of the offsetting relationship we have with each of our counterparties provided for in our revolving credit agreement and various hedge contracts. See Note 5 — "Fair Value Measurements" for further information.

The following derivative contracts were in place at December 31, 2009:

Crude Oil		Volume/Month	Price/Unit	Fair Value
Jan 2010-Dec 2010	Swap	4,250 Bbls	$72.32	$ (507,441)
Jan 2010-Dec 2010	Collar	9,000 Bbls	$65.28-$70.60	(1,383,360)
Jan 2010-Dec 2010	Collar	7,604 Bbls (1)	$110.00-$181.25	2,645,094
Jan 2011-Dec 2011	Swap	3,300 Bbls	$70.74	(598,177)
Jan 2011-Dec 2011	Collar	7,000 Bbls	$64.50-$69.50	(1,488,200)
Natural Gas				
Jan 2010-Jun 2010	Swap	45,833 Mmbtu (1)	$6.25 (2)	183,556
Jan 2010-Dec 2010	Swap	29,000 Mmbtu	$7.88	730,483
Jan 2010-Dec 2010	Collar	351,000 Mmbtu	$7.57-$9.05	7,959,998
Jan 2010-Dec 2010	Collar	85,167 Mmbtu (1)	$9.00-$15.25	3,361,059
Jan 2011-Dec 2011	Collar	266,000 Mmbtu	$7.32-$8.70	4,001,569
			Commodity price derivative instruments	14,904,581
Interest rate		**Notional Amount**	**Fixed Rate**	
Jan 2010-Dec 2010	Swap	$50,000,000	1.50%	(448,987)
Jan 2010-May 2011	Swap	$150,000,000	2.90%	(4,161,482)
			Interest rate derivative instruments	(4,610,469)
			Total net fair value asset of derivative instruments	$ 10,294,112

(1) Average volume per month for the remaining contract term
(2) Average price for the contract term

The following table details the effect of derivative contracts on the Consolidated Statements of Operations:

Contract Type	Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Recognized in Income — Twelve Months Ended December 31, 2009	2008	2007
Commodity prices	Operating revenues	$ 38,783,854	$ (9,310,057)	$ 2,996,776
Interest rate	Interest expense	(4,432,364)	(3,988,231)	297,592
	Realized gain (loss)	$ 34,351,490	$ (13,298,288)	$ 3,294,368
Commodity prices	Other income (expense)	$ (24,937,637)	$ 51,094,422	$ (14,186,093)
Interest rates	Other income (expense)	1,075,057	(1,685,461)	(4,000,065)
	Unrealized gain (loss)	$ (23,862,580)	$ 49,408,961	$ (18,186,158)

8. Accrued Liabilities

Accrued liabilities consist of the following:

	December 31, 2009	December 31, 2008
Lease acquisition costs	$ —	$ 11,246,914
Capital drilling and operating costs	2,018,250	9,202,949
Smith acquisition closing settlement	—	1,291,847
Accrued compensation	1,200,000	1,244,772
Interest and loan fees	4,108,101	988,521
Equity offering costs	699,240	—
Other	826,719	394,057
	$ 8,852,310	$ 24,369,060

9. Asset Retirement Obligations

A reconciliation of our asset retirement obligation liability is as follows:

	December 31, 2009	December 31, 2008
Balance beginning of year	$ 13,068,542	$ 7,555,491
Accretion expense	842,008	620,813
Liabilities incurred	105,289	4,191,364
Liabilities settled	(5,802,110)	(853,867)
Revisions	1,488,924	1,554,741
Balance end of year	$ 9,702,653	$ 13,068,542

During 2009, we disposed of $5.3 million of asset retirement liabilities assumed by the buyer as part of the sale of the Southwest Louisiana properties. Additional liabilities of $1.5 million were primarily recognized earlier in the year as revisions associated with increased retirement costs in the now sold Southwest Louisiana properties.

During 2008, we recognized additional liabilities of $4.2 million, primarily related to new wells acquired through our acquisition and drilling programs. We also had $1.6 million in revisions primarily related to increased retirement costs at our Grand Lake facility in South Louisiana.

10. Debt

On May 8, 2007, we entered into a $400.0 million revolving credit agreement with Wells Fargo Bank, National Association, as agent, and the lender parties thereto, which amended and restated our revolving credit agreement dated as of July 15, 2005, as amended. On May 31, 2007, we amended and restated this agreement (as amended and restated, our “revolving credit agreement”). Our revolving credit agreement provides for aggregate borrowings of up to $400.0 million for acquisitions of crude oil and gas properties and for general corporate cash requirements. The revolving credit agreement includes usual and customary covenants for credit facilities of the respective types and sizes, including, among others, limitations on liens, hedging, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, certain leases and investments outside of the ordinary course of business, as well as events of default. The revolving credit agreement also contains certain financial covenants, including maintaining (i) a ratio of current assets (including borrowing base availability and excluding derivative instruments) to current liabilities (excluding current portion of long-term debt and derivative instruments) of at least 1.0 to 1.0. On November 6, 2009, we entered into a second and a third amendment to our revolving credit agreement. These amendments provided, among other things, for (i) a change in the voting percentages required for certain amendments or waivers from 50.1% to 60%, and (ii) a waiver of the current ratio and the leverage ratio covenants for the quarter ended September 30, 2009.

Effective December 7, 2009, we entered into a fourth amendment to our revolving credit agreement. This amendment provides, among other things, that, (i) the ratio of our total debt to Adjusted EBITDAX for any four trailing fiscal quarters may not be greater than 3.50x as of the end of any fiscal quarter ending on or prior to December 31, 2010, and 3.25x as of the end of any fiscal quarter ending thereafter, and (ii) the ratio of Adjusted EBITDAX to cash interest expense for any four trailing fiscal quarters may not be less than 2.25x as of the end of any fiscal quarter ending on or prior to December 31, 2010, and 2.75x as of the end of any fiscal quarter ending thereafter. EBITDAX represents net income (loss) before net interest expense, taxes, and depreciation, amortization and exploration expenses. Adjusted EBITDAX, as defined in our credit agreements, represents EBITDAX as further adjusted for (i) unrealized gain or loss on derivative instruments, (ii) non-cash share-based compensation charges, (iii) impaired assets, (iv) other financing costs and (v) gains or losses on the disposition of assets, all of which will be required in determining our compliance with financial covenants under our revolving credit facility and second lien term loan agreement.

In addition, this amendment also provides that the borrowing base under our revolving credit agreement was redetermined to be $105.0 million at December 22, 2009 and that we may issue up to $200 million in senior unsecured notes. Any such issuance of senior unsecured notes will reduce our borrowing base by 25% of the net proceeds from such issuance in excess of $150 million. At December 31, 2009, no senior unsecured notes were outstanding.

Borrowings under our revolving credit agreement are subject to a borrowing base limitation based on our proved crude oil and natural gas reserves. The next borrowing base re-determination under our revolving credit agreement is scheduled for May 1, 2010 and is subject to semi-annual redeterminations, although our lenders may elect to make one additional redetermination between scheduled redetermination dates. Our revolving credit agreement has a term of four years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2011. Our revolving credit agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Advances under our revolving credit agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the higher of the lender's "prime rate" and the Federal Funds rate. The interest rate on the LIBOR loans fluctuates based upon the rate at which Eurodollar deposits in the LIBOR market are quoted for the maturity selected. Pursuant to an amendment to our revolving credit agreement, dated July 31, 2009, the applicable margin was increased from between 1.25% and 2.00% to between 2.75% and 3.50%, for LIBOR loans, and from zero and 0.50% to between 1.50% and 2.00%, for base rate loans. The specific interest margin applicable is determined by, in each case, the percent of the borrowing base utilized at the time of the credit extension. LIBOR loans of one, two, three and six months may be selected. Pursuant to that same amendment, the commitment fee payable on the unused portion of our borrowing base was increased from 0.375% to 0.50%, which fee accrues and is payable quarterly in arrears.

On May 8, 2007, we entered into a five-year second lien credit agreement with Credit Suisse, as agent, and the lender parties thereto which provided for term loans, made to us in a single draw, in an aggregate principal amount of $150.0 million (our "second lien credit agreement"). On May 8, 2007, we borrowed $150.0 million pursuant to this second lien credit agreement to pay the consideration for the acquisition of the STGC Properties and to refinance certain existing indebtedness. Our second lien credit agreement replaced our then existing $150.0 million subordinate credit agreement, which was paid off in full and terminated at closing. Our second lien credit agreement matures on May 8, 2012.

On May 13, 2009, we entered into a second amendment to our second lien credit agreement (including with an affiliate of OCM GW Holdings, LLC, a related party (*"Oaktree Holdings"*), which, among other things, (i) modified the leverage ratio covenant to be no greater than the leverage ratio under our revolving credit agreement plus 0.25, (ii) modified the PV-10 ratio covenant to not be less than 1.2x beginning with the fiscal quarter ended June 30, 2009, to not be less than 1.25x, beginning with the fiscal quarter ending December 31, 2009, and to not be less than 1.5x beginning with the fiscal quarter ending December 31, 2010 and thereafter, (iii) increased the applicable margin to 8.0% for loans bearing interest at LIBOR and 7.0% for loans bearing interest at the alternate base rate, unless we meet certain leverage and PV-10 ratios, in which case the applicable margin will be 7.0% and 6.0%, respectively, (iv) set a minimum LIBOR of 3.0%, and (v) included certain fee acreage in calculations of our borrowing base after we have granted a lien on such fee acreage.

On November 6, 2009, we entered into a third amendment and waiver to our second lien credit agreement with lenders holding a majority of the then outstanding term loans under such agreement, which included an affiliate of Oaktree Holdings. The amendment and waiver provided, among other things, for a waiver of the leverage ratio covenant under that agreement for the quarter ended September 30, 2009.

At December 31, 2009, we were in compliance with the covenants under our revolving credit agreement and second lien credit agreement.

Our revolving credit agreement and our second lien credit agreement are secured by liens on substantially all of our assets, including the capital stock of our subsidiaries. The liens securing the obligations under our second lien credit agreement are junior to those under our revolving credit agreement. Unpaid interest is payable under our credit agreements as borrowings mature and renew.

We constructively fixed the interest rate on $200.0 million of our variable rate debt by entering into interest rate swaps at a weighted average swap price of 2.6%.

At December 31, 2009, we had $41.0 million outstanding under our revolving credit agreement and $150.0 million outstanding under our second lien credit agreement, with availability under our revolving credit agreement of $64.0 million.

Promissory Notes. On November 6, 2009, we issued an unsecured promissory note in an aggregate principal amount of $10.0 million to Wells Fargo Bank, National Association, the administrative agent and a lender under our revolving credit agreement. All of the proceeds of this promissory note were used to repay indebtedness outstanding under our revolving credit agreement. As support for this contingent obligation to purchase this promissory note, Oaktree Holdings, a related party, deposited $10.0 million in escrow for the benefit of Wells Fargo Bank, National Association.

On December 22, 2009, we repaid this $10.0 million unsecured promissory note with proceeds from our equity offering and Oaktree Holdings' $10.0 million deposit in escrow was released back to Oaktree Holdings from Wells Fargo Bank, National Association. All $1.7 million debt issuance costs associated with the issuance of the $10.0 million promissory note were expensed in conjunction with the repayment of the $10.0 million promissory note.

As consideration for Oaktree Holdings' agreement to deposit $10.0 million in escrow as described above, we issued an unsecured subordinated promissory note on November 6, 2009 in aggregate principal amount of $2.0 million to Oaktree Holdings, a related party. The indebtedness under the promissory note bears interest at a per annum rate equal to 8.0% and matures on the later of (i) November 8, 2012 and (ii) the date six months after payment in full in cash of all Obligations (as such term is defined under our credit agreements), and the termination of all commitments to extend credit under our credit agreements. The promissory note is subordinated in right of payment to the prior payment in full in cash of all obligations under our credit agreements. At December 31, 2009, the carrying fair value of this debt was calculated as $1.7 million, net of discount, using the estimated market value interest rate at the time of issuance.

Our debt consists of the following:

	December 31, 2009	December 31, 2008
Revolving Credit Agreement with a borrowing base of $105.0 million and $200.0 million, respectively, secured by all of our assets, interest at the higher of prime or Federal Fund rate plus a margin of 1.50% to 2.00%, or, at the option of the holder, LIBOR plus a margin of 2.75% to 3.50% depending on the percent of the borrowing base utilized at the time of the credit extension, due and payable in full in May 2011 (interest rate in effect at December 31, 2009 was 3.75%)	41,000,000	126,673,074
Second Lien Credit Agreement for a term loan in a single draw, secured by all of our assets, subordinate and junior to the Senior Revolving Credit Agreement, floating interest rates at LIBOR plus 7.00% or base rate plus 6.00%, maturing in May 2012, with a minimum LIBOR rate of 3.00% (interest rate in effect at December 31, 2009 was 11.00%)	150,000,000	150,000,000
Subordinated Promissory Note, bearing interest at 8.00%, due and payable in full in November 2012, net of discount of $250,249	1,749,751	—
Notes payable to finance vehicles, payable in aggregate monthly installments of approximately $3,600, including interest of 5.99% to 10.49% at December 31, 2009 per annum; secured by the related equipment; due various dates through 2010	19,014	57,720
	192,768,765	276,730,794
Less current portion	(19,014)	(90,368)
Total long-term debt	$ 192,749,751	$ 276,640,426

Estimated annual maturities for long-term debt are as follows:

	Long-Term Debt
2010	$ 19,014
2011	41,000,000
2012	151,749,751
2013	—
2014	—
	$ 192,768,765

11. Commitments and Contingencies

Lease Obligations

We currently lease and sublease, through January 31, 2014, 54,939 square feet of executive and corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Total general and administrative rent expense for the years ended December 31, 2009, 2008 and 2007, were approximately $2.2 million, $1.4 million and $0.4 million, respectively. Effective January 1, 2010, we have subleased to a subtenant for approximately one year, 27,144 square feet of this space for a total rental of approximately $1.0 million.

We have entered into various vehicle leases for periods ranging from 24 to 50 months. These contracts will expire at various times with the latest contract expiring in September 2010. We also have various other equipment leases that expire in 12 to 36 months, with the latest contract expiring in June 2011. Total operational rent expense for the years ended December 31, 2009, 2008 and 2007, were approximately $3.0 million, $3.4 million and $0.9 million, respectively.

The following table provides information about our total operating lease obligations as of December 31, 2009:

		Operating leases
2010	$	1,951,198
2011		1,437,749
2012		1,419,933
2013		1,419.933
2014		118,328
Thereafter		—
Total	$	6,347,141

Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations or from disputes with vendors in the normal course of business. During the second quarter of 2009, holders of oil and gas leases in East Texas (Haynesville Shale) filed two causes of action against us alleging breach of contract for not paying lease bonuses on certain oil and gas leases pursued by our leasing agent. The damages alleged are approximately $2.4 million and there are approximately $300,000 in written demands from other holders of leases in this area that we believe may contemplate legal proceedings. We are vigorously defending these lawsuits, and believe we have meritorious defenses. We do not believe that these claims will have a material adverse affect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

Employment Agreements

In December 2008, we entered into amended and restated employment agreements with our President/Chief Executive Officer and Senior Vice President/Chief Financial Officer. Each agreement has a term of three years with automatic yearly extensions unless we or the executive officer elects not to extend the agreement. These agreements provide for an annual base salary of $370,000 and $340,000, respectively. If the contracts are terminated by us without cause or by the employee for good reason, and the employee has been in compliance with employee contract terms, the employee may receive a cash payment equal to 2.99 times the sum of the current calendar year's base salary plus prior year's annual cash incentive bonus, health insurance benefits for 36 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

Also in December 2008, we entered into amended and restated employment agreements with our three other Senior Vice Presidents and entered into an employment agreement with our one Vice President. Each agreement has a term of two years with automatic yearly extensions unless we or the executive officer elects not to extend the agreement. These agreements provide for an annual base salary ranging from $186,300 to $220,000. If the contracts are terminated by us without cause or by the employee for good reason, and the employee has been in compliance with the employee contract terms, the employee is entitled to receive a cash payment equal to two times current year base salary plus prior year bonus, health insurance benefits for 24 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

12. Stockholders' Equity

	2009	2008
Preferred Stock		
Series G, par value $0.01; 81,000 shares authorized; zero and 80,500 issued and outstanding at December 31, 2009 and 2008, respectively.	$ —	$ 805
Series H, par value $0.01; 6,500 shares authorized; zero and 2,100 shares issued and outstanding at December 31, 2009 and 2008, respectively.	—	21
	$ —	$ 826
Common Stock		
Par value $0.001; 200,000,000 shares authorized; 38,516,658 and 5,787,287 shares issued and outstanding as of December 31, 2009 and 2008, respectively	$ 38,578	$ 5,808
Treasury Stock		
At cost, 61,546 and 20,625 shares as of December 31, 2009 and 2008, respectively	$ (384,312)	$ (250,594)

The Series G Preferred Stock bore cumulative dividends of 8% per year, compounded quarterly, and had an aggregate liquidation preference of $40.3 million, excluding accumulated and undeclared dividends. For the first four years after issuance, we deferred the payment of dividends on the Series G Preferred Stock and these deferred dividends were also convertible into our Common Stock at $9.00 per share. These dividends were not being accrued in our financial statements until such time as they were declared by the Board of Directors and became due and payable. In addition, the Series G Preferred Stock was entitled to vote on an as-converted basis with the holders of our Common Stock and, as a class, was entitled to nominate and elect a majority of the members of our Board of Directors. The Series G Preferred Stock was senior to all of our outstanding capital stock in liquidation preference.

The Series H Preferred Stock was required to be paid a dividend of 40 shares of Common Stock per one share of Series H Preferred Stock per year. In addition, the Series H Preferred Stock was convertible into Common Stock at a conversion price of $3.50 per share. The Series H Preferred Stock had an aggregate liquidation value of $1.1 million and was senior to all of our outstanding capital stock in liquidation preference other than the Series G Preferred Stock.

All classes of preferred stockholders had a liquidation preference over common stockholders of $500 per preferred share, plus accrued dividends. On December 22, 2009, all shares of preferred stock, including accumulated dividends, were converted into Common Stock in conjunction with our equity offering.

13. Share-Based Compensation

As of December 31, 2009, we had share-based compensation, which includes both stock options and restricted stock awarded to employees and directors.

Incentive Plans

In the third quarter 2008, our Board of Directors formally adopted an amendment to our performance based cash bonus plan and adopted a new performance based long term stock bonus plan for the benefit of all employees - the Crimson Cash Incentive Bonus Plan (*"CIBP"*) and the Crimson Long-Term Incentive Plan (*"LTIP"*), respectively. Both plans, and specific targeted performance measures for the fiscal year 2008 under those plans, were previously approved by the Compensation Committee. Upon achieving the established performance levels, bonus awards were calculated as a percentage of base salary for the plan year. The plan awards were disbursed in the first quarter of the following year. Employees must have been employed by us at the time that final plan awards were dispersed to have been eligible.

The CIBP awards were paid out in cash (*"Cash Awards"*). The performance targets were evaluated on a quarterly basis and used to estimate the approximate expense earned to date. Approximately $1.2 million was recognized as compensation expense related to the Cash Awards for the twelve months ended December 31, 2008. The Board of Directors suspended the CIBP for 2009. However, discretionary cash bonus awards of approximately $1.2 million were approved by the Board of Directors for fiscal year 2009 and were paid in March 2010. The CIBP was reinstated by the Board of Directors for fiscal year 2010.

The LTIP bonus awards were paid half in the form of restricted Common Stock and half in the form of stock options (*"Stock Awards"*). The Stock Awards vest 25% per year, over the first through fourth anniversaries from the date of grant, at which time 100% of all Stock Awards will be vested. The number of shares of restricted Common Stock and the number of shares underlying the stock options granted as Stock Awards were determined based upon the fair market value of the Common Stock on the date of the grant in the first quarter 2009. The fair value of the stock options to be awarded as part of this plan was determined through use of the Black-Scholes valuation model. The Stock Awards granted pursuant to this plan were granted under the existing amended and restated 2005 Stock Incentive Plan. The Board of Directors and holders of a majority of those shares entitled to vote, approved; among other things, an increase in the number of available shares of Common Stock issuable under the amended and restated 2005 Stock Incentive Plan of 1.0 million shares.

In March 2009, the Board of Directors approved the awarding of approximately 1.1 million shares to our employees under the LTIP for the 2008 calendar year. Due to the decline in our stock price, the Board of Directors suspended the LTIP for 2009.

Stock Options

Effective July 15, 2004, we implemented our 2004 Stock Option and Compensation Plan (*"2004 Plan"*). As of December 31, 2009, there were options to purchase 16,000 shares of Common Stock outstanding and exercisable under the 2004 Plan. Effective February 28, 2005, we established our 2005 Stock Incentive Plan (*"2005 Plan"*) and authorized the issuance of up to approximately 2.9 million shares of Common Stock pursuant to awards under the plan. In the third quarter 2008, our Board of Directors and a majority of our stockholders approved an amendment and restatement of our 2005 Stock Incentive Plan that provided for an increase in the number of shares of Common Stock available for award under our 2005 Stock Incentive Plan to approximately 3.9 million shares. Approximately 2.0 million (1.2 million vested) stock options and 1.5 million (0.2 million vested) restricted shares were outstanding at December 31, 2009. Option awards outstanding under both plans have exercise prices ranging from $2.40 to $16.55 per share. At December 31, 2009, we had approximately 0.6 million shares of Common Stock available for future grant under the plan.

For stock options, we recorded $1.1 million, $4.9 million and $4.4 million in expense (included in general and administrative expense on the Consolidated Statements of Operations) for the years ended December 31, 2009, 2008 and 2007, respectively, and an estimated $1.5 million will be expensed over the remaining vesting period.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option pricing model. Assumptions used in the valuation are disclosed in the following table. Expected volatilities are based on historical volatility of our stock with a look back period based on the expected term. The expected dividend yield is zero as we have never declared dividends on our Common Stock. The expected term of options granted represents the period of time that the options are expected to be outstanding. The risk-free rate is based on U.S. Treasury bills with a duration equal or close to the expected term of the options at the time of grant. The forfeiture rate was 3.62% for 2009 and zero for 2008 and 2007, based on historical forfeitures.

	2009	2008	2007
Weighted average fair value of awards	$ 1.41	$ 7.07	$ 4.53
Pre-vest forfeiture rate	3.62%	—%	—%
Grant price	$ 2.40	$ 12.29	$ 6.86
Expected volatility	60.98%	58.61%	87.46%
Risk-free rate	2.48%	3.38%	4.12%
Expected dividend yields	—%	—%	—%
Expected term (in years)	6.25	6.0	6.0

The following table summarizes stock option activity for the three years ended December 31, 2009:

	Number of Shares Underlying Options	Weighted Average Exercise Price
Outstanding at December 31, 2006	2,341,800	$ 13.62
Granted	393,000	6.86
Exercised	(1,000)	4.50
Expired	(3,500)	7.50
Outstanding at December 31, 2007	2,730,300	12.76
Granted	126,500	12.29
Exercised	(75,000)	5.02
Expired	(27,000)	8.86
Exchanged	(1,091,260)	17.00
Outstanding at December 31, 2008	1,663,540	10.39
Granted	488,660	2.40
Cancelled/forfeited	(166,371)	6.20
Expired	(28,300)	5.56
Outstanding at December 31, 2009	1,957,529	8.82
Exercisable at December 31, 2009	1,241,111	10.95

The total intrinsic value of options exercised during the years ended December 31, 2008 and 2007 was approximately $0.5 million and $5,425 respectively. No options were exercised in 2009.

Restricted Stock Awards

For restricted stock awards, we recorded $1.3 million, $0.5 million and $0.3 million in expense (included in general and administrative expense on the Consolidated Statements of Operations) for the years ended December 31, 2009, 2008 and 2007, respectively and an estimated $3.4 million will be expensed over the remaining vesting period.

In 2009, we issued 648,936 shares of unvested Common Stock, pursuant to restricted stock awards under the LTIP for the 2008 calendar year, of which 36,366 were subsequently forfeited. The restricted stock will vest over a four year period. The fair value of the unvested Common Stock was calculated as approximately $1.6 million on the grant date and will be amortized using the straight-line method over the vesting period. We also issued 48,586 shares of Common Stock pursuant to restricted stock awards to two members of our board of directors as compensation pursuant to the Director Compensation Plan.

In the fourth quarter 2008, we issued 12,280 shares of unvested Common Stock, pursuant to restricted stock awards in exchange for the forfeiture of 24,560 substantially unvested stock option grants. The fair value of the unvested Common Stock was calculated as approximately $88,000 on the issuance date. The fair value of the forfeited stock options, calculated using the Black-Scholes valuation model, was approximately $37,000 immediately prior to the forfeiture. The sum of the incremental value of the new award over the forfeited options, approximately $52,000, and the unrecognized compensation cost for the original award as of the exchange date, approximately $45,000 are being amortized using the straight line method over the new vesting period of five years, or approximately $1,600 a month.

In the third quarter 2008, we issued 1,538 shares of Common Stock pursuant to restricted stock awards to two members of our board of directors as compensation pursuant to the Director Compensation Plan. In the third quarter 2008, we also issued 533,350 shares of unvested Common Stock pursuant to restricted stock awards in exchange for the forfeiture of 1,066,700 substantially vested stock option grants. The fair value of the unvested Common Stock was calculated as $4.9 million on the issuance date. The fair value of the forfeited stock options, calculated using the Black-Scholes valuation model, was $4.3 million immediately prior to the forfeiture. The sum of the incremental value of the new award over the forfeited options, $0.6 million, and the unrecognized compensation cost for the original award as of the exchange date, $1.4 million, are being amortized using the straight line method over the new vesting period of five years, or approximately $32,000 a month.

On September 28, 2007, we issued 250,000 shares of restricted Common Stock, pursuant to restricted stock awards, to our executive officers in recognition of their performance in consummating the STGC Properties acquisition and in recognition of the need to make appropriate adjustments to compensation commensurate with that currently provided to similarly situated executives in this highly competitive industry, and to provide equity incentives to those officers to remain with Crimson to maximize return to our stockholders. The restricted stock will vest over four years. None of the awards vested in 2007. On May 10, 2007, we issued 2,818 restricted shares of our Common Stock to certain of our directors upon reelection to the board, pursuant to the director compensation plan. The stock vested on May 10, 2008.

Restricted stock activity for the three years ended December 31, 2009 is summarized below:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1, 2007	28,644	$ 7.57
Granted	252,818	7.35
Vested	(28,644)	7.57
Non-vested as of December 31, 2007	252,818	7.35
Granted	547,168	9.12
Vested	(85,318)	7.34
Non-vested as of December 31, 2008	714,668	8.70
Granted	697,522	2.49
Vested	(127,243)	5.49
Cancelled/forfeited	(36,366)	2.40
Non-vested as of December 31, 2009	1,248,581	$ 3.41

Certain of these restricted stock awards were issued separately from the 2005 Plan.

14. Income (Loss) Per Common Share

The following is a reconciliation of the numerators and denominators used in computing income (loss) per share:

	2009	2008	2007
Net income (loss)	$ (34,069,990)	$ 46,203,218	$ (430,517)
Preferred stock dividends	(4,522,645)	(4,234,050)	(4,453,872)
Net income (loss) available to common stockholders	$ (38,592,635)	$ 41,969,168	$ (4,884,389)
Weighted-average number of shares of Common Stock – basic (denominator)	7,861,054	5,371,377	4,330,282
Income (loss) per share - basic	$ (4.91)	$ 7.81	$ (1.13)
Weighted-average number of shares of Common Stock – diluted (denominator)	7,861,054	10,360,348	4,330,282
Income (loss) per share – diluted	$ (4.91)	$ 4.46	$ (1.13)

The numerator for basic earning per share is income (loss) available to common stockholders. The numerator for diluted earnings per share is net income in 2008 and net loss available to common stockholders in 2009 and 2007, due to antidilution.

Potential dilutive securities (vested stock options, vested restricted stock, vested stock warrants and convertible preferred stock) in 2009 and 2007 have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. The potentially dilutive shares would have been 12,631,458 shares and 5,186,148 shares in 2009 and 2007, respectively.

15. Income Taxes

Income tax benefit (expense) for 2009, 2008 and 2007 consist of the following:

	2009	2008	2007
Current tax benefit (expense)	$ 122,162	$ (574,752)	$ —
Deferred tax benefit (expense)	16,572,200	(26,116,055)	410,361
Income tax benefit (expense)	$ 16,694,362	$ (26,690,807)	$ 410,361

The following is a reconciliation of effective income tax rates by applying the federal statutory rate of 35% to the income and loss for the years ended December 31, 2009, 2008 and 2007, respectively:

	2009	2008	2007
Income (Loss) Before Income Taxes	$ (50,764,352)	$ 72,894,025	$ (840,878)
Income Tax Benefit (Expense) at Statutory Rate	$ 17,767,523	$ (25,512,909)	$ 294,307
Adjustment to NOL carryforward	(1,562,704)	—	—
Effect for Permanent Items	(4,002)	(307,425)	(35,901)
State Taxes and Other	493,545	(870,473)	151,955
Income Tax Benefit (Expense)	$ 16,694,362	$ (26,690,807)	$ 410,361

As of December 31, 2009, we had net operating loss carryforwards of approximately $62.5 million, which are available to reduce future taxable income and the related income tax liability. We expect we will not be able to utilize carryforwards of approximately $9.1 million due to the limitations of Internal Revenue Code Section 382. The net operating loss carryforward expires at various dates beginning in 2010 and ending in 2030.

Significant components of our deferred tax assets and liabilities are as follows:

	December 31, 2009	December 31, 2008
Deferred tax assets		
Net operating loss carryforwards	$ 22,512,115	$ 5,599,532
Income tax credits	283,789	397,767
Deferred compensation	5,897,291	5,032,928
Other	204,613	130,910
Deferred tax assets before valuation allowance	28,897,808	11,161,137
Valuation allowance	(3,260,875)	(3,260,875)
Net deferred tax assets	25,636,933	7,900,262
Deferred tax liabilities		
Oil and gas properties	(29,467,705)	(19,712,706)
Derivative instruments	(3,537,551)	(12,128,079)
Deferred tax liabilities	(33,005,256)	(31,840,785)
Net deferred tax liabilities	$ (7,368,323)	$ (23,940,523)

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Based upon the level of historical taxable income and 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 these deductible differences net of a tax-adjusted $3.3 million valuation allowance related to the limitations of Internal Revenue Code Section 382. The amount of the deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

ASC 740, *Income Taxes* ("ASC 740") prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. There was not a material impact on our operating results, financial position or cash flows as a result of the adoption of the provisions of ASC 740. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows:

	Unrecognized Tax Benefits
Balance at December 31, 2008	$ 518,219
Additions based on tax positions related to the current year	—
Additions based on tax positions related to prior years	—
Additions due to acquisitions	—
Reductions due to a lapse of the applicable statute of limitations	—
Balance at December 31, 2009	$ 518,219

Generally, our income tax years of 2006 through 2009 remain open and subject to examination by Federal tax authorities or the tax authorities in Texas, Louisiana and Colorado which are the jurisdictions where we have our principal operations. These audits can result in adjustments of taxes due or adjustments of the net operating loss carryforwards that are available to offset future taxable income.

Our policy is to recognize interest and penalties related to uncertain tax positions as income tax benefit (expense) in our Consolidated Statements of Operations. For the years ended December 31, 2009 and 2008, respectively, we recorded no interest expense and penalties related to unrecognized tax benefits associated with uncertain tax positions recognized in our provision for income taxes.

The total amount of unrecognized tax benefit if recognized that would effect the effective tax rate was zero.

Our tax returns are subject to periodic audits by the various jurisdictions in which we operate. These audits can result in adjustments of taxes due or adjustments of the net operating loss carryforwards that are available to offset future taxable income.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to December 31, 2010. However, due to the complexity of the application of tax law and regulations, it is possible that the ultimate resolution of these positions may result in liabilities which could be materially different from these estimates.

16. Quarterly Results (Unaudited)

Summary data relating to the results of operations for each quarter for the years ended December 31, 2009 and 2008 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2009				
Net revenues	$ 30,730,867	$ 28,619,937	$ 26,900,404	$ 26,196,438
Income (loss) from operations	3,004,219	2,262,485	3,533,485	(9,188,025)
Net income (loss) available to common stockholders	3,952,884	(14,380,332)	(9,742,289)	(18,422,898)
Income(loss)per common share				
Basic	$ 0.66	$ (2.24)	$ (1.51)	$ (1.86)
Diluted	$ 0.46	$ (2.24)	$ (1.51)	$ (1.86)
Weighted average shares outstanding				
Basic	6,026,888	6,421,225	6,444,013	9,907,024
Diluted	10,856,219	6,421,225	6,444,013	9,907,024
2008				
Net revenues	$ 45,036,091	$ 53,013,341	$ 53,751,791	$ 34,967,050
Income (loss) from operations	35,400,343	24,745,879	(4,316,240)	(9,734,688)
Net income (loss) available to common stockholders	(361,339)	(26,618,441)	49,160,564	19,788,384
Income(loss)per common share				
Basic	$ (0.07)	$ (5.15)	$ 9.19	$ 3.41
Diluted	$ (0.07)	$ (5.15)	$ 4.87	$ 1.97
Weighted average shares outstanding				
Basic	5,149,341	5,173,463	5,351,146	5,806,988
Diluted	5,149,341	5,173,463	10,317,629	10,580,260

17. Oil and Gas Reserves (unaudited)

All information set forth herein relating to our proved reserves, estimated future net cash flows and present values is taken or derived from reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us. No reports on our reserves have been filed with any federal agency. In accordance with the SEC's guidelines, our estimates of proved reserves and the future net revenues from which present values are derived beginning with 2009 are based on an unweighted 12-month average of the first-day-of-the-month price for the period January through December 2009 held constant throughout the life of the properties. Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net revenues, but such costs do not include debt service, general and administrative expenses and income taxes.

The following unaudited table sets forth proved natural gas, crude oil and natural gas liquids reserves, all within the United States, at December 31, 2009, 2008 and 2007, together with the changes therein. Natural gas liquids became a significant addition to our reserves since the acquisition of the STGC properties in May 2007.

	Natural Gas (Mcf)	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Total (Mcfe)
QUANTITIES OF PROVED RESERVES:				
Balance December 31, 2006	31,387,548	2,500,819	—	46,392,462
Revisions (1)	(21,184,471)	(521,000)	3,692,173	(2,157,433)
Extensions, discoveries and additions	7,716,613	194,846	183,699	9,987,883
Purchase	82,386,946	1,137,402	—	89,211,358
Sales (3)	—	—	—	—
Production	(9,067,777)	(408,864)	(285,907)	(13,236,403)
Balance December 31, 2007	91,238,859	2,903,203	3,589,965	130,197,867
Revisions (2)	(9,678,571)	(408,055)	(752,440)	(16,641,541)
Extensions, discoveries and additions	11,948,600	470,828	603,414	18,394,052
Purchase	17,311,835	107,332	474,642	20,803,679
Sales (3)	(1,516,480)	(11,440)	—	(1,585,120)
Production	(13,135,509)	(498,143)	(516,352)	(19,222,479)
Balance December 31, 2008	96,168,734	2,563,725	3,399,229	131,946,458
Revisions	(11,753,495)	139,160	(179,222)	(11,993,867)
Extensions, discoveries and additions	1,901,483	—	—	1,901,483
Sales (3)	(6,042,695)	(412,054)	(153,199)	(9,434,213)
Production	(10,414,441)	(326,707)	(426,095)	(14,931,253)
Balance December 31, 2009	69,859,586	1,964,124	2,640,713	97,488,608
PROVED DEVELOPED RESERVES:				
December 31, 2007	67,996,730	2,266,017	2,683,678	97,694,900
December 31, 2008	66,711,779	1,615,974	2,422,878	90,944,891
December 31, 2009	49,075,274	1,274,262	1,976,757	68,581,388
PROVED UNDEVELOPED RESERVES:				
December 31, 2007	23,242,119	637,185	906,287	32,502,967
December 31, 2008	29,456,955	947,751	976,351	41,001,567
December 31, 2009	20,784,312	689,862	663,956	28,907,220

(1) The reporting of net NGL sales volumes began in mid-year 2007 following the close of the EXCO acquisition. The end of year 2007 reserve report was updated to reflect this change in reporting. The resulting changes in 2007 volumes for natural gas and natural gas liquids are reflected in revisions.

(2) Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors.

(3) Sales are calculated based on the beginning of the year reserves adjusted for current year production with no adjustment for revisions.

Standardized measure of discounted future net cash flows relating to proved reserves:

	2009	2008	2007
Future cash inflows	$ 475,007,800	$ 749,121,400	$ 1,125,374,500
Future production and development costs			
Production	156,581,500	214,969,100	258,028,900
Development	55,021,500	86,068,300	65,779,100
Future cash flows before income taxes	263,404,800	448,084,000	801,566,500
Future income taxes	—	(46,695,950)	(198,920,968)
Future net cash flows after income taxes	263,404,800	401,388,050	602,645,532
10% annual discount for estimated timing of cash flows	(86,982,100)	(140,485,818)	(203,122,453)
Standardized measure of discounted future net cash flows	$ 176,422,700	$ 260,902,233	$ 399,523,079

The following reconciles the change in the standardized measure of discounted future net cash flows:

	2009	2008	2007
Beginning of year	$ 260,902,233	$ 399,523,079	$ 77,413,027
Changes from:			
Purchases of proved reserves	—	69,628,594	324,427,750
Sales of producing properties	(25,350,512)	(2,817,597)	—
Extensions, discoveries and improved recovery, less related costs	3,864,603	77,931,000	43,636,200
Sales of natural gas, crude oil and natural gas liquids produced, net of production costs	(87,312,694)	(148,588,993)	(85,425,742)
Revision of quantity estimates(1)	(26,277,363)	(44,029,057)	(15,028,200)
Accretion of discount	29,094,980	39,952,308	10,240,157
Change in income taxes	30,352,367	101,522,054	(88,340,375)
Changes in estimated future development costs	14,712,798	(32,461,195)	(8,693,224)
Development costs incurred that reduced future development costs	7,085,480	20,342,054	20,561,154
Change in sales and transfer prices, net of production costs	(25,324,647)	(227,731,733)	82,348,797
Changes in production rates (timing) and other	(5,324,545)	7,631,719	38,383,535
End of year	$ 176,422,700	$ 260,902,233	$ 399,523,079

(1) Periodic revisions to the quantity estimates may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and
Stockholders of Crimson Exploration Inc.

We have audited in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements of Crimson Exploration Inc. and subsidiaries referred to in our report dated March 16, 2010, which is included in the annual report to stockholders. Our audits of the basic financial statements included the financial statement schedule listed in the index appearing under Item 15(2), which is the responsibility of the Company's management. In our opinion, this financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ GRANT THORNTON LLP

Houston, Texas
March 16, 2010

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 and 2007

DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIONS	BALANCE AT END OF PERIOD
For the year ended December 31, 2007:				
Allowance for doubtful accounts	$ 118,110	96,905	—	$ 215,015
Valuation allowance for deferred tax assets	$ 3,079,715	362,319	—	$ 3,442,034
For the year ended December 31, 2008:				
Allowance for doubtful accounts	$ 215,015	—	—	$ 215,015
Valuation allowance for deferred tax assets	$ 3,442,034	—	(181,159)	$ 3,260,875
For the year ended December 31, 2009:				
Allowance for doubtful accounts	$ 215,015	239,676	(43,367)	$ 411,324
Valuation allowance for deferred tax assets	$ 3,260,875	—	—	$ 3,260,875