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, 2008
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission file number: 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	**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, 2008, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $43,712,249 based on the closing sales price of $16.20 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 25, 2009, there were 5,789,387 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2009 Annual Meeting, expected to be filed within 120 days of our fiscal year end, are incorporated by reference into Part III.

FORWARD-LOOKING STATEMENTS

Certain terms that we use in our industry are italicized and defined in the "Glossary of Industry Terms and Abbreviations". Unless otherwise indicated, all references to "Crimson", "GulfWest", the "Company", "we", "us" and "our" refer to Crimson Exploration Inc. and our subsidiaries.

We make forward-looking statements throughout this Annual Report within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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

- *estimates of proved reserve quantities and net present values of those reserves;*
- *estimates of probable and possible reserve quantities;*
- *reserve potential;*
- *business strategy;*
- *estimates of future commodity prices;*
- *amounts and types of capital expenditures and operating expenses;*
- *expansion and growth of our business and operations;*
- *expansion and development trends of the crude oil and natural gas industry;*
- *production of natural gas, crude oil and natural gas liquids reserves;*
- *exploration prospects;*
- *wells to be drilled, and drilling results;*
- *operating results and working capital;*
- *future methods, types and availability of financing;*
- *senior management team and other key personnel;*
- *acquisitions and divestitures;*
- *volatility of common stock and stockholder interests;*
- *financial and credit market conditions, including hedging activity;*
- *legislative or regulatory changes;*
- *competitive conditions, including supply and demand of products; and*
- *global economic conditions*

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 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 set forth 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.

PART I

ITEM 1. Business

Our Business

Crimson Exploration Inc., together with our subsidiaries, ("*Crimson*", "*we*", "*our*", "*us*") is a growing independent natural gas and crude oil company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties, primarily in the onshore U.S. Gulf Coast and South Texas regions. Our strategic focus is in this area because of the lower risk, high cash flow and high return opportunities in known prolific producing trends in these regions. We also have operations and prospective acreage in the Denver Julesburg Basin of Colorado and own acreage positions in the Haynesville Shale play in East Texas, an emerging natural gas resource play. We intend to grow our *proved reserves* and production through acquisitions, and through development, exploitation and exploration activities on our multi-year project inventory in our current productive asset base and acreage inventory.

During the last three years, we have grown *proved reserves* from 40.9 *Bcfe* at December 31, 2005 to 131.9 *Bcfe* at December 31, 2008. On a daily basis, we have increased production from 7,265 *Mcfe* in 2005 to 52,520 *Mcfe* in 2008.

We have developed a significant project inventory of lower risk exploitation drilling locations associated with our existing properties, with exploratory potential in *prospect* acreage in South Texas and in our recently acquired Haynesville Shale acreage. At December 31, 2008, our estimated *proved reserves* were approximately 131.9 *Bcfe* with an estimated PV-10 of $290.9 million based on the West Texas Intermediate posted price on December 31, 2008 of $41.00 per barrel for crude oil, and the Henry Hub spot market price of $5.71 per *Mcf* for natural gas on December 31, 2008, adjusted by lease for quality, energy content, transportation fees and regional price differentials. Our estimated *proved reserves* as of December 31, 2008 were approximately 73% natural gas, 12% crude oil and 15% natural gas liquids. We had 358 gross (183 net) producing wells, 51% of which we operate, which produced an average of 52,520 *Mcfe*/day for the year ended December 31, 2008.

We will continue to expand our role in the domestic energy industry by (i) acquiring additional interests in oil and natural gas properties, (ii) increasing the production and reserve base of our existing *producing properties*, (iii) developing exploratory prospects through our internal *prospect* generation team, and (iv) complementing our strategy of growth through exploitation and exploration of conventional sources of hydrocarbons with the pursuit of the Haynesville Shale gas resource play in East Texas.

We have structured our organization into specific geographic regions to provide for concentration of effort, experience and accountability on the part of our technical evaluation and exploitation teams, as well as our production and operations groups. We have evaluation and operations teams dedicated to each particular region that are responsible for maximizing results from that region. Our regions include the following:

- *South Texas* – primarily the Cage Ranch field in Brooks County, the Southwest Speaks field in Lavaca County, the North Bob West field in Zapata County, the Brushy Creek field in DeWitt County, and the Lobo trend production and acreage in Zapata and Webb Counties;

- *Southeast Texas* – primarily the Felicia field area in Liberty County, Texas;

- *Southwest Louisiana* – primarily the Fenton field area in Calcasieu Parish and our legacy Grand Lake and Lacassine fields in Cameron Parish; and

- *Colorado and Other* – primarily producing assets and undeveloped acres in the Denver Julesburg Basin in Colorado, mostly in Adams County, and a minor crude oil property in Mississippi.

In addition, we own various *working interests* in a number of non-operated properties that we classify separately as "non-operated", primarily along the Gulf Coast.

We also own interests in East Texas, primarily approximately 18,325 gross (11,876 net) recently acquired undeveloped acres in the highly prospective Haynesville Shale play in Sabine, Shelby and San Augustine Counties.

Our gross revenues are derived from the following sources:

1. Natural gas, crude oil and natural gas liquids sales that are proceeds from the sale of natural gas, crude oil and natural gas liquids production. This represents over 99% of our gross revenues.

2. Operating overhead and other income that consists primarily of administrative fees received from other *working interest* owners for operating natural gas and crude oil properties and for marketing and transporting natural gas and crude oil for those owners.

Our operations are considered to fall within a single industry segment, which is the acquisition, development, exploitation and exploration of oil and gas properties. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our Company

We were formed as a corporation under the laws of the State of Utah in 1987 as Gallup Acquisitions, Inc., and subsequently changed our name to First Preference Fund, Inc in 1992. We became a Texas corporation by a merger effected in July 1992, through which our name became GulfWest Oil Company. On May 21, 2001, we changed our name to GulfWest Energy Inc.

On June 29, 2005 we merged with and into Crimson Exploration Inc., a Delaware corporation (*"Crimson"*), for the purpose of changing our state of incorporation from Texas to Delaware (the *"Reincorporation"*). The Reincorporation was accomplished pursuant to an Agreement and Plan of Merger, dated June 28, 2005, which was approved by GulfWest's stockholders at the 2005 Annual Stockholders' Meeting held June 1, 2005.

Prior to March 2, 2006 Crimson Exploration Inc. had six active and three inactive, direct or indirect, wholly owned subsidiaries. The active subsidiaries were GulfWest Oil and Gas Company, GulfWest Oil and Gas Company (Louisiana) LLC, SETEX Oil and Gas Company, RigWest Well Service, Inc., Dutch West Oil Company and GulfWest Development Company. On January 5, 2006 we formed Crimson Exploration Operating, Inc. ("*CEO*"), a Delaware corporation, as our wholly owned subsidiary through which all oil and gas operations are now being conducted. Effective March 2, 2006 we merged all our subsidiaries referred to above into this newly formed corporation. LTW Pipeline Co. remains an inactive subsidiary of Crimson Exploration Inc.

On May 8, 2007, CEO acquired certain oil and gas properties and related assets in the South Texas and Gulf Coast areas of Louisiana and Texas (the "*STGC Properties*") pursuant to a Membership Interest Purchase and Sale Agreement (the "*Purchase Agreement*") from EXCO Resources, Inc. ("*EXCO*") through the acquisition of 100% of the membership interest of Southern G Holdings, LLC ("*SGH*"). These properties were operated by SGH as a wholly owned subsidiary of CEO until SGH was merged into CEO on December 31, 2007. The consolidated statements of operations include the results of operations of the STGC Properties from May 2007 to present.

Our principal office is located at 717 Texas Avenue, Suite 2900, Houston, Texas 77002 and our telephone number is (713) 236-7400.

Highlights from 2008

During 2008 we produced an estimated 19.2 *Bcfe* of natural gas equivalents, or an average of approximately 52,520 *Mcfe* per day, an approximate 45% increase over the 13.2 *Bcfe* of natural gas equivalents, or 36,300 *Mcfe* per day, produced in 2007. At year end 2008, we were producing approximately 49,000 *Mcfe* per day. The increase in production for the year was attributable to the South Texas and Gulf Coast producing assets acquired in May 2007 from EXCO and certain South Texas assets acquired from Smith Production Inc. (*"Smith"*) in May 2008.

In May 2008, we acquired four producing gas fields and undeveloped acreage in South Texas from Smith for a purchase price of $65.0 million with an effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.0 million for the period between the effective date and the closing date, the cash consideration was $58.0 million, subject to final adjustment by the end of the first quarter of 2009. 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 and Lavaca Counties. We acquired an interest in over 16,000 gross acres with these fields, most of which is held by production. We added 21 *Bcfe* to our *proved reserves* through the Smith acquisition at an average cost of $2.82 per *Mcfe* of *proved reserves* as of the closing date.

During 2008, we drilled a total of 31 gross (14 operated and 17 non-operated) wells on primarily exploitation opportunities, with an overall success rate of 89% on the completed wells, with four wells in process at year end. We participated in the drilling of seven operated and 13 non-operated wells within our South Texas Region, with 19 completed successfully. Of the 19 successful wells, 16 commenced production in 2008, two wells commenced production in 2009 and one well was sold. We also participated in the drilling of seven operated and two non-operated wells in the Liberty County area of our Southeast Texas Region, a key area acquired in May 2007. Seven of those wells were completed successfully and commenced production at various times during 2008. We also participated in the drilling of two successful non-operated wells in Weld County, Colorado which commenced production in 2008.

In the second half of 2008, we obtained natural gas and crude oil leases from mineral interest owners covering approximately 18,325 gross (11,876 net) acres in the Haynesville Shale natural gas play in East Texas. We are currently developing a drilling strategy for this acreage, including unit and well spacing, with the expectation that we will commence our first well during the third quarter of 2009. We intend to continue to acquire additional acreage that complements our existing position and expect to have an active drilling program in this area by mid-year 2010.

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 final 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 senior revolving credit facility and to help finance our acquisition of the Smith properties. Our net book value of these assets sold was $18.8 million, which resulted in a gain of $15.6 million.

Our Business Strategy

We pursue a balanced mix of acquisition, exploitation and exploration activities to create value for our stockholders. Our geographic focus area for these natural gas and crude oil related activities is primarily the Gulf Coast region of the United States. Natural gas, crude oil and natural gas liquids activities, such as property acquisitions, *prospect* generation, exploration and development drilling, *workovers* and *recompletions* and other lease operating activities are the principal activities in which we engage.

The key elements of our business strategy are:

- *<u>Make opportunistic acquisitions that meet our strategic and financial objectives</u>*. We seek to acquire natural gas and crude oil properties that we believe complement our existing properties in our core areas of operation, as well as other properties that provide opportunities for the addition of reserves and production through development, exploitation and exploration.

- *<u>Exploit our multi-year project inventory</u>*. We believe our multi-year drilling inventory of exploitation opportunities on our existing *producing properties* provide us with a solid platform to continue growing our reserves and production for the next several years. We believe generating and investing in high cash flow, high return opportunities in the Gulf Coast region is the best value-added strategy to pursue for our stockholders. We also believe that the complementing of that conventional strategy with our investment in the longer life profile of the Haynesville Shale resource play in East Texas gives us a good balance of high return assets and a multi-year inventory of drilling locations for reserve growth.

- *<u>Explore in defined producing trends</u>*. Our exploration activities currently consist primarily of step-out drilling in known, producing formations and exploration opportunities in our acreage in 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 4,060 square miles of 3D data and 1,325 linear miles of 2D data. We believe that our high drilling success rate reflects our expertise in our operating regions, as well as our balance of low-to-moderate-risk activities with selected higher potential exploration activities.

Our Employees

At March 25, 2009, we had 81 full time employees, of whom 23 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 favorable.

Regulations

Federal and State Regulations

Exploration for, and production of, crude oil and natural gas are extensively regulated at the federal, state and local levels. Crude oil and natural gas development and production activities are subject to various laws and regulations (and orders of regulatory bodies pursuant thereto) governing a wide variety of matters, including, among others, allowable rates of production, transportation, prevention of waste and pollution and protection of the environment. Laws affecting the crude oil and natural gas industry are under constant review for amendment or expansion and frequently increase the regulatory burden on companies. Our ability to economically produce and sell crude oil and natural gas is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the US. Many of these rules and regulations are often difficult and costly to comply with, and carry substantial penalties for failure to comply. These laws, regulations and orders may restrict the rate of crude oil and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory burden on the crude oil and natural gas industry increases our costs of doing business and consequently affects our profitability.

Other federal agencies have certain authority over our business, such as the Internal Revenue Service and the Securities and Exchange Commission ("*SEC*").

Environmental Regulations

The oil and gas business is subject to environmental hazards, such as crude oil spills, gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These environmental hazards could expose us to material liabilities for property damages, personal injuries or other environmental harm, including costs of investigating and remediating contaminated properties. In addition, we also may be liable for environmental damages caused by the previous owners or operators of properties that we have purchased or are currently operating. A variety of stringent federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things, well drilling or *workover*, operation and abandonment, waste management, land reclamation, and controlling air, water and waste emissions.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production and may affect our costs of acquisitions. Environmental laws may, in the future, cause a decrease in our production or an increase in the costs of production, development or exploration. Pollution and similar environmental risks generally are not fully insurable.

We have not incurred any material costs relating to our compliance with federal, state or local laws during the year ended December 31, 2008, or during the subsequent interim period.

Title to Properties

Our properties are subject to customary *royalty interests*, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our *producing properties*. We secure title opinions prior to closing on *producing property* acquisitions. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. Before we commence drilling operations, we make title investigations and receive title opinions rendered by outside counsel. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these encumbrances will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Competition

The oil and gas industry is highly competitive, and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market natural gas, crude oil and natural gas liquids, 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 of the oil and gas we produce. 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 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 do not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Executive Officers

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

ITEM 1A. Risk Factors

Risks Related to Our Business

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. 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 crude oil producing countries, including countries in the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain crude 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 revisions to our estimated *proved reserves*.

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 has slowed substantially. At the present time, the rate at which the global economy will slow has become increasingly uncertain. A continued slowing of global economic growth, and, in particular, in the United States, will likely continue to 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. Natural gas and crude oil prices have dropped dramatically in 2008, from record levels of approximately $13 per Mmbtu and $142 per barrel, respectively, in July 2008 to below $6 per Mmbtu and $42 per barrel, respectively as of December 31, 2008. 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.

We have a substantial amount of indebtedness, a major portion of which is contingent upon semi-annual redeterminations of a borrowing base that determines the maximum amount that can be borrowed under our senior revolving credit facility. If an event of default occurs under either of our credit facilities, all of our indebtedness may become due and payable, which may adversely affect our cash flow and our ability to operate our business.

As of December 31, 2008, we had outstanding debt of $276.7 million under our credit facilities, and we have the ability to borrow up to an additional $73.3 million under our senior revolving credit facility to fund capital expenditures or for general corporate purposes. Our senior revolving credit facility limits the amounts we can borrow to a borrowing base amount. The borrowing base is subject to scheduled semi-annual redeterminations; however, the lenders reserve the right to request one unscheduled redetermination of the borrowing base between each scheduled redetermination, should they believe conditions warrant. We are likely to incur a borrowing base reduction at the next redetermination date. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or, if we notify the bank, we have the option to pay the excess over time or to pledge other natural gas and crude oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our revolving credit facility. See “Item 7. Management’s Discussion and Analysis of Operations – Liquidity and Capital Resources”.

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 facility and second lien term loan facility 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 facilities 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 facilities. 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 Operations – Liquidity and 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 the risk factors titled "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 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."

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 current 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 two 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. These variables could have a material adverse effect on our business, financial condition, results of operations and the market value of our common stock.

We may not be able to 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 existing 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 existing operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses; and
- our management's attention may be diverted from other business concerns.

We are also exposed to risks that are commonly associated with oil and gas property acquisitions, 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.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates 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 economic assumptions. 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 2. Properties" 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.

You should not assume that the present value referred to in this Annual Report is 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 SEC requirements, 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, 2008 was based on a Henry Hub spot market price of $5.71 per Mmbtu for natural gas and a West Texas Intermediate posted price of $41.00 per barrel for crude oil on December 31, 2008. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of December 31, 2008, would have decreased from $290.95 million to $288.15 million. If natural gas prices were $0.10 per *Mcf* lower than the price used, our PV-10 as of December 31, 2008, would have decreased from $290.95 million to $285.47 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.

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 incurring 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.

Approximately 31% of our total estimated proved reserves at December 31, 2008 were proved undeveloped reserves, which are by their nature less certain.

Recovery of *proved undeveloped reserves* requires significant capital expenditures and successful drilling operations. The reserve data set forth 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.

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

The natural gas and crude oil 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 temporary borrowings under our revolving credit facility. 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 and crude oil we are able to produce from existing wells;
- the prices at which natural gas and crude oil 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 facilities contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base is redetermined resulting in a lower borrowing base under our senior revolving credit facility, we may be unable to obtain financing otherwise available under our senior revolving credit facility. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and 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.

Drilling for natural gas and crude oil may not be profitable.

Any wells that we drill may be dry wells or wells that are not sufficiently productive to be profitable after drilling. Such wells will have a negative impact on our profitability. In addition, our properties may be susceptible to drainage from production by operators on adjacent properties.

The interpretation and analysis of 3D seismic data does not allow the interpreter to know if hydrocarbons are present or economically producible.

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. 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. In addition, the use of 3D seismic and other advanced technologies require greater predrilling expenditures than traditional drilling strategies.

Drilling for and producing natural gas and crude oil 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 and crude oil 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;
- blowouts;
- 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; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; damage to or destruction of property, natural resources and equipment; pollution; environmental contamination or loss of wells; 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. 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 past growth has been partially attributable to acquisitions of producing natural gas and crude oil properties with proved reserves.

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, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to fully assess their capabilities or deficiencies. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not be observable.

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 and crude oil 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 and crude oil 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 all 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 operator's:

- nature and timing of drilling and operational activities;
- timing and amount of capital expenditures;
- expertise and financial resources;
- the approval of other participants in drilling wells; and
- 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 natural gas, crude oil or natural gas liquids may have several adverse affects, 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, possibly causing us to lose 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 and crude oil *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 field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

During periods when the price of natural gas, crude oil and natural gas liquids increases, we have generally encountered an increase in the cost of securing drilling rigs, equipment and supplies. Shortages or the high cost of drilling rigs, equipment, supplies and personnel may also develop during periods of rising commodity prices. 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.

Competition in the natural gas and crude oil 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 and 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. Although we have entered into long-term agreements with all of our executive officers to protect our interests in those relationships, we can give no assurance that all or any of these persons will remain with us. The loss of the services of one or more members of our senior management team or 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 laws 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 authority relating to the exploration for, and the development, production and transportation 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.

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 operations and other activities. These costs and liabilities could arise under a wide range of environmental, health and safety laws that cover, among other things, emissions into the air and water, habitat and endangered species protection, the containment and disposal of hazardous substances, 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 strict 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, and the issuance or 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 or 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. 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. In addition, many countries as well as several states of the U.S. have agreed to regulate emissions of “greenhouse gases”. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas and crude oil, are greenhouse gases. New environmental regulations may be adopted in the future that may unfavorably impact us, our suppliers and our customers. Regulation of greenhouse gases could adversely impact our operations and the demand for natural gas, crude oil and natural gas liquids in the future.

If we are unable to successfully prevent or address material weakness 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 error 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. If we are unable to successfully prevent or address material weakness 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.

A terrorist attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for natural gas, crude oil and natural gas liquids, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Natural gas, crude oil and natural gas liquids related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure or facilities we use for the production, transportation or marketing of our natural gas, crude oil and natural gas liquids are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

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

To achieve 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 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 and natural gas liquids production. As of December 31, 2008, 7,336,500 Mmbtu of natural gas and 343,752 barrels of crude oil and natural gas liquids have been hedged for 2009, 5,582,004 Mmbtu of natural gas and 250,248 barrels of crude oil and natural gas liquids have been hedged for 2010, and 3,192,000 Mmbtu of natural gas and 123,600 barrels of crude oil and natural gas liquids have been hedged for 2011.

Our actual future production and our actual outstanding debt 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 and interest rate 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 or by the repayment of borrowing on debt, resulting in a substantial diminution of our liquidity. 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.

Historically, we have been dependent on a few purchasers since we operate in a single industry; the loss of one or more purchasers could adversely affect our financial condition and results of operations.

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, 2008, 2007 and 2006, our top ten purchasers collectively represented approximately 71%, 73% and 95% of total revenues, respectively. Our three largest purchasers in 2008 accounted for 28%, 8% and 6% 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.

One stockholder holds a significant number of our shares and the right to elect a majority of our board of directors, which will limit stockholders' ability to influence corporate activities and may adversely affect the market price of our common stock.

Of the approximately 5.8 million shares of our common stock outstanding, OCM GW Holdings LLC *("OCMGW")* holds approximately 2.0 million of those shares directly and has the right to acquire approximately 5.9 million shares of common stock pursuant to conversion of shares of Series G Preferred Stock, including undeclared convertible dividends, and Series H Preferred Stock held by it. At December 31, 2008, OCMGW would hold approximately 68% of our outstanding Common Stock on a fully diluted basis, assuming conversion of all preferred stock and accumulated dividends and the exercise of all vested stock options. The Series G Preferred Stock and the Series H Preferred stock vote together with the common stock on an as-converted basis. In addition, pursuant to the terms of Series G Preferred Stock, the holders of the Series G Preferred Stock, voting as a class, have the right to elect a majority of our board of directors. OCMGW currently owns approximately 95% of the Series G Preferred Stock. As a result of this stock ownership and its ability to elect a majority of our directors, OCMGW possesses 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.

The interests of OCMGW may conflict with the interests of our other stockholders.

Messrs. B. James Ford and Adam C. Pierce, who are representatives of OCMGW, serve on our board of directors. OCMGW is in the business of trading securities of, and/or investing in, energy companies. As a result of these relationships, when conflicts between the interests of OCMGW, on the one hand, and the interests of our other stockholders, on the other hand, arise, these directors may not be disinterested. OCMGW may, from time to time, compete directly or indirectly with us or prevent us from taking advantage of corporate opportunities. OCMGW 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. Although our directors and officers have a duty of loyalty to us under Delaware law and our certificate of incorporation, transactions that we enter into in which a director or officer has a conflict of interest are generally permissible so long as (1) the material facts relating to the director's or officer's relationship or interest as to the transaction are disclosed to our board of directors and a majority of our disinterested directors, or a committee consisting solely of disinterested directors, approves the transaction, (2) the material facts relating to the director's or officer's relationship or interest as to the transaction are disclosed to our stockholders and a majority of our disinterested stockholders approves the transaction or (3) the transaction is otherwise fair 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 it. 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, particularly during 2008 and during the first quarter of 2009, 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.

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, our revolving credit facility, second lien term loan facility and the terms of our preferred stock restrict the payment of dividends. Accordingly, stockholders may have to sell some or all of their common stock in order to generate cash flow from their investment.

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

We are a Delaware corporation, and the anti-takeover provisions of the Delaware law impose various impediments to the ability of a third party to acquire control of us, even if a change of control would be beneficial to our existing stockholders. In addition, 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 our equity sponsor, could discourage potential acquisition proposals and could delay or prevent a change of control.

We have "blank check" preferred stock.

Our certificate of incorporation authorizes the board of directors to issue up to approximately 10 million shares of 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 (*"Common Stock"*). As of December 31, 2008, there are 5.8 million shares of Common Stock issued and outstanding. Since the holders of our Common Stock do not have cumulative voting rights, the holder(s) of a majority of the shares of Common Stock present, in person or by proxy, will be able to elect two 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.

The number of shares of outstanding Common Stock could increase significantly as a result of the exercise of outstanding stock options or conversion of our preferred stock.

If all of the Common Stock underlying our granted employee stock options, Series G Preferred Stock and Series H Preferred Stock is issued by us, the number of our outstanding shares of Common Stock would increase to approximately 13.8 million shares. Currently, we are authorized to issue 200.0 million shares of our Common Stock, 5.8 million shares of which are outstanding as of December 31, 2008. It is impossible to say how many shares, if any, we will issue and how many shares, in turn, will be resold. However, it is possible that our stock price could decline significantly as a result of an increased number of shares being offered into the market.

Our Common Stock is thinly traded and there is no active trading market for our Common Stock and an active trading market may not develop.

The trading volume of our Common Stock has historically been low and reliable market quotations for our Common Stock have not been available, partially due to the fact that we are not listed on an exchange and our Common Stock is only traded over-the-counter. In addition some institutional investors may be prohibited from investing in securities that are not traded on a national exchange. An active trading market for our Common Stock may not develop or, if developed, may not continue, and a holder of any of our securities may find it difficult to dispose of, or to obtain accurate quotations as to the market value of such securities.

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 facility 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 facility.

ITEM 2. Properties

At December 31, 2008, we owned interests in a total of 678 *gross wells*, of which 358 were *producing*, 294 were inactive and 26 were injection or saltwater wells. We owned an average 51% *working interest* in the 358 gr*oss* (183 *net*) producing wells. 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*.

Proved Reserves

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 SEC's guidelines, our estimates of *proved reserves* and the future net revenues are made using year end natural gas and crude oil sales prices held constant throughout the life of the properties. Operating costs, development costs and 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.

There are numerous uncertainties inherent in estimating natural gas, crude oil and natural gas liquids reserves and their values, including many factors beyond our control. The reserve data, set forth in this report, are based upon estimates. *Reservoir* engineering involves estimating the size of underground accumulations of natural gas, crude oil and natural gas liquids that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation of that data and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development, exploitation and exploration activities, prevailing natural gas, crude oil and natural gas liquids prices, operating costs and other factors. Such revisions may be material. Accordingly, reserve estimates are often different from the quantities of natural gas, crude oil and natural gas liquids that are ultimately recovered and are dependent upon the accuracy of the assumptions upon which they are based. We cannot assure you that the estimates contained in this report are accurate predictions of our natural gas, crude oil and natural gas liquids reserves or their values. Estimates with respect to *proved reserves* that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves with additional future data such as production history could result in potentially substantial variations in the estimated reserves.

The following table reflects our estimated *proved reserves* at December 31 for each of the preceding three years.

	2008	2007	2006
Crude Oil (MBbl)			
Developed	1,616	2,266	2,249
Undeveloped	948	637	252
Total	2,564	2,903	2,501
Natural Gas (MMcf)			
Developed	66,712	67,997	27,145
Undeveloped	29,457	23,242	4,243
Total	96,169	91,239	31,388
Natural Gas Liquids (Bbls)			
Developed	2,423	2,684	—
Undeveloped	976	906	—
Total	3,399	3,590	—
Total (MMcfe)	131,947	130,197	46,394

We have significantly increased our *proved reserves* and production through acquisition and drilling since our recapitalization in early 2005. In 2007, we tripled our reserve size through the acquisition from EXCO of *producing properties* in the South 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 *proved reserves* through the Smith acquisition 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 have also been successful at adding reserves through our exploitation program. In 2008, we drilled a total of 31 gross (14 operated and 17 non-operated) wells on primarily exploitation opportunities, with an overall success rate of 89% on the completed wells, with four wells in process at year end. Through our 2008 drilling program, we added an estimated 18.4 *Bcfe* of natural gas reserves.

Approximately 69% of our total *proved reserves* was classified as proved developed at December 31, 2008.

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 Standard Board. Future net cash flow represents future gross cash flow from the production and sale of *proved reserves*, net of 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. We cannot assure you that the *proved reserves* will all be developed within the periods used in the calculations or those prices and costs will remain constant.

	2008	2007	2006
Future cash inflows	$ 749,121,400	$ 1,125,374,500	$ 313,312,927
Future production and development costs:			
Production	214,969,100	258,028,900	108,693,762
Development	86,068,300	65,779,100	26,229,488
Future cash flows before income taxes	448,084,000	801,566,500	178,389,677
Future income taxes (1)	(46,695,950)	(198,920,968)	(43,534,046)
Future net cash flows after income taxes	401,388,050	602,645,532	134,855,631
10% annual discount for estimated timing of cash flows (1)	(140,485,818)	(203,122,453)	(57,442,604)
Standardized measure of discounted future net cash flows (1)	$ 260,902,233	$ 399,523,079	$ 77,413,027

(1) The prices utilized in the estimation of our 2008 *proved reserves* were based on the West Texas Intermediate posted price on December 31, 2008 of $41.00 per barrel for crude oil, and the Henry Hub spot market price of $5.71 per *Mcf* for natural gas, adjusted by lease for quality, energy content, transportation fees and regional price differentials.

Significant Properties

Summary information on our properties with *proved reserves* is set forth below as of December 31, 2008.

	Productive Wells		Proved Reserves				Present Value (1)
Regions	Gross Productive Wells	Net Productive Wells	Crude Oil	Natural Gas	Natural Gas Liquids	Total	Amount
			(MBbl)	(MMcf)	(MBbl)	(MMcfe)	($000)
South Texas	105	82	545	47,284	1,675	60,602	$ 101,838
Southeast Texas	35	27	965	17,669	988	29,393	89,685
Southwest Louisiana	21	12	425	6,490	227	10,398	27,162
Colorado & Other	25	19	317	4,775	—	6,675	7,002
Non-Operated	172	43	312	19,951	509	24,879	65,263
Total	358	183	2,564	96,169	3,399	131,947	$ 290,950

(1) The prices utilized in the estimation of our 2008 *proved reserves* were based on the West Texas Intermediate posted price on December 31, 2008 of $41.00 per barrel for crude oil, and the Henry Hub spot market price of $5.71 per Mcf for natural gas, adjusted by lease for quality, energy content, transportation fees and regional price differentials.

Production, Revenue and Price History

The following table sets forth information (associated with our *proved reserves*) regarding production volumes of crude oil, natural gas and natural gas liquids, revenues and expenses attributable to such production (all net to our interests) and certain price and cost information as of December 31 for each of the preceding three years.

	2008	2007	2006
Production			
Natural gas (Mcf)	13,135,509	9,067,777	1,542,423
Crude oil (Bbl)	498,143	408,864	184,881
Natural gas liquids (Bbl)	516,352	285,907	—
Total (Mcfe)	19,222,479	13,236,403	2,651,709
Revenue			
Natural gas sales	$ 116,414,956	$ 67,867,603	$ 10,569,705
Crude oil sales	41,860,385	27,021,298	10,908,030
Natural gas liquids sales	27,404,774	14,272,712	—
Total	$ 185,680,115	$ 109,161,613	$ 21,477,735
Lease Operating Expenses	$ 20,824,629	$ 12,033,963	$ 5,633,069
Production and Ad Valorem Taxes	$ 16,266,493	$ 11,701,908	$ 1,894,520
Production Data			
Average sales price (1)			
Per barrel of crude oil	$ 84.03	$ 66.09	$ 59.00
Per Mcf of natural gas	$ 8.86	$ 7.48	$ 6.85
Per barrel of natural gas liquids	$ 53.07	$ 49.92	$ —
Per Mcfe	$ 9.66	$ 8.25	$ 8.10
Average expenses per Mcfe			
Lease operating	$ 1.08	$ 0.91	$ 2.12
Production and ad valorem taxes	$ 0.85	$ 0.88	$ 0.71
Exploration expenses(2)	$ 0.52	$ 0.24	$ 0.25
Depreciation, depletion and amortization	$ 2.63	$ 2.33	$ 1.52
General and administrative(3)	$ 1.17	$ 1.10	$ 3.29

(1) Average sales prices are shown net of the settled amounts of our natural gas, crude oil and natural gas liquids hedge contracts. Average sales prices per Mcfe, before adjustments for the hedge contracts, were $10.14, $8.02 and $8.34 in 2008, 2007 and 2006, respectively.

(2) In November 2008, we released undeveloped leasehold interests that we acquired from Core Natural Resources in Culberson County, Texas in 2006, and recorded a $7.1 million exploration expense.

(3) Non-cash stock compensation expense related to our adoption of SFAS 123R on January 1, 2006 was $0.26, $0.32 and $1.39 per Mcfe in 2008, 2007 and 2006, respectively.

Productive Wells

The following table shows the number of *productive wells* we own by location at December 31, 2008:

	Gross Crude Oil Wells	Net Crude Oil Wells	Gross Natural Gas Wells	Net Natural Gas Wells
South Texas	—	—	105	82
Southeast Texas	7	6	28	21
Southwest Louisiana	7	6	14	6
Colorado & Other	18	13	7	6
Non-operated	15	3	157	40
Total	47	28	311	155

In addition, we have 294 inactive wells (150 net) and 26 salt water disposal wells (13 net).

Developed and Undeveloped Acreage

The following table shows the approximate developed and undeveloped acreage that we have an interest in, by location, at December 31, 2008. Developed acreage is acreage spaced or assigned to *productive well*s. 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.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
South Texas	74,259	40,798	14,889	12,509
Southeast Texas	24,118	13,140	3,466	2,550
Southwest Louisiana	9,778	4,250	1,838	1,412
Colorado & Other	7,370	5,185	9,560	6,692
East Texas	—	—	18,325	11,876
Total	115,525	63,373	48,078	35,039

Drilling Results

The following table shows the results of the gas wells drilled and completed for operated and non-operated properties for each of the last three fiscal years ended December 31, 2008. There were no crude oil wells drilled during this time period.

	2008	2007	2006
Gross Gas Wells			
Development	20	9	4
Exploratory	5	8	—
Dry	2	4	—
Total	27	21	4
Net Gas Wells			
Development	10.74	1.07	3.50
Exploratory	1.05	1.65	—
Dry	0.80	0.72	—
Total	12.59	3.44	3.50

At December 31, 2008, we had no exploratory and 4 gross (1.14 net) development wells in progress.

Costs Incurred

The following table shows the costs incurred in our producing activities for operated and non-operated properties for the past three years ended December 31, 2008:

	2008	2007	2006
Property Acquisitions:			
Proved	$ 60,765,315	$ 238,036,360	$ —
Unproved	57,203,337	30,407,525	8,745,363
Development Costs	86,685,192	30,814,788	6,465,719
Exploration Costs	2,520,389	13,405,017	10,783,663
Total	$ 207,174,233	$ 312,663,690	$ 25,994,745

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 and geological and geophysical expenses.

Property Dispositions

The following table shows oil and gas property dispositions for the three years ended December 31, 2008:

	2008	2007	2006
Oil and gas properties	$ 21,765,688	$ —	$ —
Accumulated DD&A	(1,659,588)	—	—
Oil and gas properties, net	$ 20,106,100	$ —	$ —

The dispositions in 2008 resulted in a net gain of $15.2 million.

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.

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. As of March 25, 2009, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

ITEM 4. Submission of Matters to a Vote of Security Holders

We did not submit any matters to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2008.

PART II

ITEM 5. Market for Registrant's Common Equity and Related Stockholder Matters

Our Common Stock is traded over-the-counter (OTC:BB) under the symbol "CXPO".

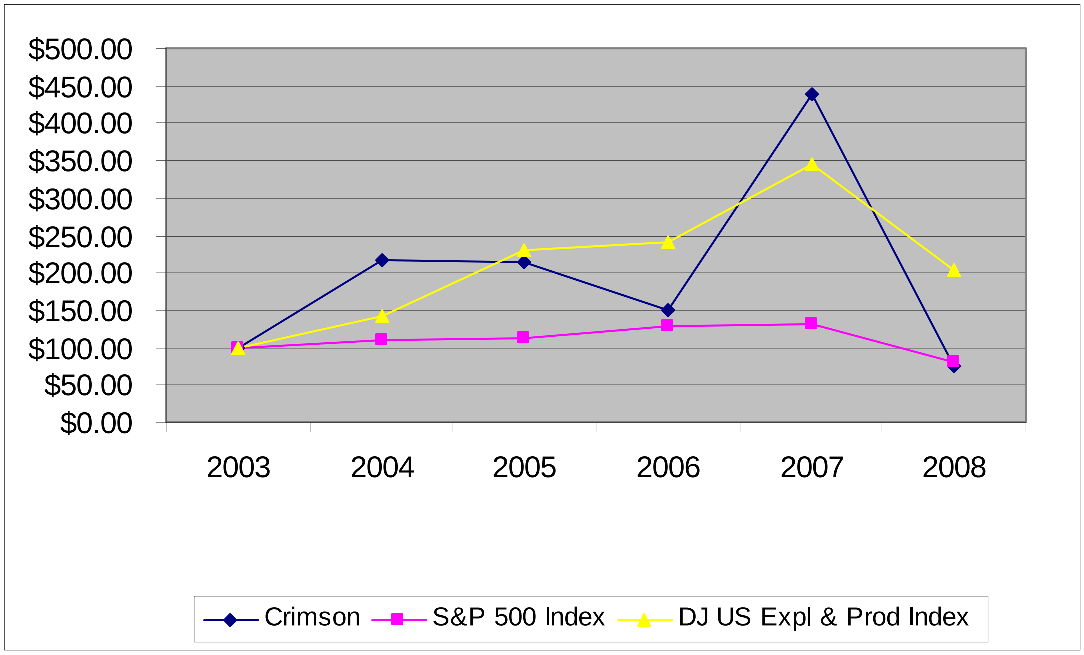
The high and low trading prices for the Common Stock for each quarter in 2008 and 2007 are set forth below. The trading prices represent prices between dealers, without retail mark-ups, mark-downs, or commissions, and may not necessarily represent actual transactions.

	High	Low
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, 2008 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 (formerly the Dow Jones Secondary Oils Stock Index). The comparison assumes $100 was invested on December 31, 2003 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, 2003	$	100.00	$	100.00	$	100.00
December 31, 2004	$	216.67	$	108.99	$	140.45
December 31, 2005	$	214.29	$	112.26	$	230.50
December 31, 2006	$	148.81	$	127.55	$	241.19
December 31, 2007	$	438.10	$	132.06	$	343.97
December 31, 2008	$	73.81	$	81.23	$	204.21

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. Our preferred stock is senior to our Common Stock regarding liquidation. The holders of the preferred stock do not have voting rights (except as discussed below) 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.

As of March 25, 2009, there were a total of 82,600 shares of preferred stock issued and outstanding in Series G and Series H Preferred Stock.

The 80,500 shares of our Series G Preferred Stock bear cumulative dividends of 8% per year, compounded quarterly, and have an aggregate liquidation preference of $40.3 million, excluding accumulated and undeclared dividends. For the first four years after issuance, we may defer the payment of dividends on the Series G Preferred Stock and these deferred dividends will also be convertible into our Common Stock at $9.00 per share. These dividends are not currently being accrued in our financial statements until such time as they are declared by the Board of Directors and become due and payable. In addition, the Series G Preferred Stock is entitled to vote on an as-converted basis with the holders of our Common Stock and, as a class, is entitled to nominate and elect a majority of the members of our Board of Directors. The Series G Preferred Stock is senior to all of our outstanding capital stock in liquidation preference.

Prior to the third quarter of 2007, we accumulated undeclared dividends, on a simple or non-compounded basis. During the third quarter 2007, the Company was notified by the majority holder of the Series G Preferred Stock (*"Preferred Stock Owner"*) that they believed that certain provisions of the Certificate of Designations for the Series G Preferred Stock resulted in a compounding effect. After reviewing its interpretation, and consulting with legal counsel, the Company and the Preferred Stock Owner settled their dispute and agreed to calculate the accrued, undeclared and unpaid dividends on a compounded basis. This new basis for calculating the dividend accrual was documented in a clarification memo between the parties. In accordance with Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections" (*"SFAS 154"*), the change in the method of calculating the accrued, undeclared dividend was a change in accounting estimate necessitated by the "new information" that became available with the written agreement between the parties in the settlement of the dispute. The net effect of the change in the accounting estimate was an increase of $0.7 million in Dividends on Preferred Stock in the Consolidated Statements of Operations for the year ended December 31, 2007, of which approximately $0.4 million was related to prior years, and $0.1 million and $0.2 million was related to the first and second quarters of 2007, respectively.

The 2,100 shares of our Series H Preferred Stock are 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 is convertible into Common Stock at a conversion price of $3.50 per share. The Series H Preferred Stock has an aggregate liquidation value of $1.1 million and is senior to all of our outstanding capital stock in liquidation preference other than the Series G Preferred Stock.

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 25, 2009, there were 5.8 million shares of Common Stock issued and outstanding and held by approximately 213 record holders. Our Common Stock is traded over-the-counter (OTC:BB) under the symbol "CXPO". Fidelity Transfer Company, 8915 South 700 East #102, Sandy, Utah 84070, (801) 562-1300 is the transfer agent for the Common Stock.

Holders of Common Stock are entitled, among other things, to one vote per share 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 majority of the outstanding shares of the Common Stock and Series H Preferred Stock (on an as converted basis) have the ability to elect all of the directors that the Series G Preferred Stock does not elect. On February 28, 2005, the holders of the Series G Preferred Stock were granted the right to elect a majority of our Board of 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.

Share-Based Compensation

At December 31, 2008, we had outstanding employee stock options, under our 2004 Stock Option and Compensation Plan, to purchase 44,300 (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. Approximately 1.6 million (0.8 million vested) stock options and 0.5 million restricted shares were outstanding under this plan at December 31, 2008. Option awards outstanding under both plans have exercise prices ranging from $4.50 to $16.55 per share. In addition, we had approximately 0.7 million shares of unvested restricted stock awards. In 2008, 85,318 shares of Common Stock vested, of which 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, 2008, we had approximately 1.5 million shares of Common Stock available for future grant under the plan. In March 2009, the Board of Directors approved the awarding of approximately 1.1 million shares to our employees under the performance-based Long-Term Incentive Plan ("*LTIP*") for the 2008 calendar year. After the issuance of these stock awards, approximately 0.4 million stock awards will remain in the plan. Due to the recent decline in our stock price, the Board of Directors suspended the LTIP for 2009. Any share-based bonus awards for fiscal year 2009 will be awarded at the discretion of the Board of Directors.

Recent Sales of Unregistered Securities

As shown in the table below, during 2008, 2007 and 2006 we issued Common Stock not registered under the Securities Act of 1933, 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	Derivative	Holder(s)	Underlying Shares	Exercise/ Conversion Price	Consideration
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
12/20/07	Common Stock	Existing Stockholder	50,000	$ 80.00	Series D Preferred Stock Conversion
10/05/07	Common Stock	Accredited Investors	2,818	NA	Director Compensation
9/28/07	Common Stock	Accredited Investors	250,000	NA	Compensation to Company's Executive Officers
5/29/07	Common Stock	Existing Stockholder	428,572	$ 3.50	Series H Preferred Stock Conversion
5/29/07	Common Stock	Existing Stockholder	291,247	$ 9.00	Series E Preferred Stock Conversion
5/8/07	Common Stock	Accredited Investor	750,000	NA	EXCO Acquisition
5/12/06	Common Stock	Accredited Investors	2,410	NA	Director Compensation
3/01/06	Common Stock	Accredited Investors	26,234	NA	Bonus compensation to Company's Executive Officers

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,				
	2008	**2007**	**2006**	**2005**	**2004**
Income Statement Data					
Operating revenues	$186,768,273	$109,543,208	$ 21,659,481	$ 17,682,808	$ 11,207,673
Income (loss) from operations (1)	46,095,294	33,616,299	(2,458,685)	637,823	(476,264)
Net income (loss)	46,203,218	(430,517)	1,858,944	(3,543,239)	8,072,221
Dividends on preferred stock	(4,234,050)	(4,453,872)	(3,648,925)	(3,562,472)	(455,612)
Net income (loss) available to common stockholders	41,969,168	(4,884,389)	(1,789,981)	(7,105,711)	7,616,609
Net income (loss), per share					
Basic	$ 7.81	$ (1.13)	$ (0.55)	$ (2.66)	$ 4.11
Diluted	$ 4.46	$ (1.13)	$ (0.55)	$ (2.66)	$ 2.41
Weighted average shares outstanding					
Basic	5,371,377	4,330,282	3,231,000	2,673,882	1,853,503
Diluted	10,360,348	4,330,282	3,231,000	2,673,882	3,161,828

(1) Our adoption of SFAS 123(R) on January 1, 2006 resulted in compensation expense, reflected in G&A in our Statements of Operations, of $5.0 million, $4.2 million and $3.7 million, in 2008, 2007 and 2006, respectively.

Balance Sheet Data

Current assets	$ 46,347,553	$ 36,481,565	$ 4,231,983	$ 5,825,078	$ 3,808,878
Total assets	511,545,789	398,935,074	84,702,722	63,114,949	57,876,164
Current liabilities	83,989,610	48,879,245	10,932,155	6,855,735	37,249,217
Noncurrent liabilities	305,933,376	280,402,748	12,444,784	3,453,952	1,950,304
Stockholders' equity	$121,622,803	$ 69,653,081	$ 61,325,783	$ 52,805,262	$ 18,676,643

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

Overview

We are primarily engaged in the acquisition, development, exploitation and exploration of natural gas, crude oil and natural gas liquids, primarily in the onshore producing regions of the United States. Our focus is on increasing production from our existing properties through further exploitation, development and exploration, and on acquiring additional interests in oil and natural gas properties. Our gross revenues are derived from the following sources:

1. Natural gas, crude oil and natural gas liquids sales that are proceeds from the sale of natural gas, crude oil and natural gas liquids production. This represents over 99% of our gross revenues.

2. Operating overhead and other income that consists primarily of administrative fees received for operating natural gas and crude oil properties for other *working interest* owners and for marketing and transporting natural gas for those owners.

Acquisitions

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 effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.0 million for the period between the effective date and the closing date. The cash consideration was $58.0 million, subject to final adjustment, by the end of the first quarter of 2009. 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 per day at closing, which resulted in a 13% increase in our then current net daily production.

The $58.0 million adjusted price, with adjustment of the reserves for approximately one *Bcfe* of production for the interim operations between the effective date and closing, represented 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 the senior revolving credit facility. 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.

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 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.

Prospect Acquisitions

During the third and fourth quarters of 2008, we acquired approximately 11,876 net undeveloped acres in Sabine, Shelby and San Augustine counties Texas on which we will target the Haynesville Shale, James Lime, and Travis Peak formations. We are currently developing a drilling strategy for this acreage, including unit and well spacing, with the expectation that we will commence our first well during the third quarter of 2009. We intend to continue to acquire additional acreage that complements our existing position and expect to have an active drilling program in this area by mid-year 2010. We financed this acquisition with cash flows from operations and from borrowings available under the senior credit facility.

Dispositions in 2008

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 final 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 Senior Revolving Credit Agreement (defined below) and to help finance our acquisition of the properties from Smith. Our net book value of these assets sold was $18.8 million, which resulted in a gain of $15.6 million.

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, 2008 Compared to Year Ended December 31, 2007

Revenues

	2008	2007	Change	Percent Change
		(in millions, except percentages)		
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%
Product revenues	$ 185.7	$ 109.2	$ 76.5	70.1%

Natural Gas, Crude Oil And Natural Gas Liquids Sales. Revenues from the sale of crude oil, natural gas and natural gas liquids, net of the realized effects of our hedging instruments, increased by 70.1%, to $185.7 million in 2008 compared to $109.2 million in 2007. The increase in net revenues was primarily due to increases in net realized commodity prices, the success experienced in our drilling program, the full-year effect of the May 2007 acquisition of the STGC Properties and the seven-month effect of the May 2008 South Texas acquisition from Smith, offset by lost production, and natural gas liquids not processed, due to Hurricanes Gustav and Ike.

	2008	2007	Change	Percent Change
Sales (production) 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%

For 2008, sales volumes increased approximately 45.2% compared to production in 2007. We had approximately 425,000 *Mcfe* of production deferred 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
Realized prices (net of hedges):				
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%

	2008	2007	Change	Percent Change
Prices before effects of hedges:				
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%

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
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%
Depreciation, depletion & amortization	50.5	30.8	19.7	64.0%
General and administrative	22.4	14.5	7.9	54.5%
Operating expenses	$ 120.0	$ 72.2	$ 47.8	66.2%

	2008	2007	Change	Percent Change
Selected Costs ($ per Mcfe):				
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%
Depreciation, depletion & amortization	$ 2.63	$ 2.33	$ 0.30	12.9%
General and administrative expenses	$ 1.17	$ 1.10	$ 0.07	6.4%

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 in 2006 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 higher production volumes and a higher DD&A rate.

Impairment of Oil and Gas Properties. Impairment 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 the abandonment of the Rodessa formation development 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 $5.0 million ($0.26 per *Mcfe*) and

$4.7 million ($0.32 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 facilities 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 facilities and to commitment fees related to the unused portion of the credit facilities.

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.

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.

<u>Year Ended December 31, 2007 Compared to Year Ended December 31, 2006</u>

Revenues

	2007	2006	Change	Percent Change
		(in millions, except percentages)		
Revenues:				
Natural gas sales	$ 67.9	$ 10.6	$ 57.3	540.6%
Crude oil sales	27.0	10.9	16.1	147.7%
Natural gas liquids sales	14.3	—	14.3	—%
Total operating revenues	$ 109.2	$ 21.5	$ 87.7	407.9%

Natural Gas, Crude Oil And Natural Gas Liquids Sales. Revenues from the sale of crude oil, natural gas and natural gas liquids, net of the realized effects of our hedging instruments, increased by 407.9%, to $109.2 million in 2007 compared to $21.5 million in 2006. 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.

	2007	2006	Change	Percent Change
Sales (production) volumes:				
Natural gas (Mcf)	9,067,777	1,542,423	7,525,354	487.9%
Crude oil (Bbl)	408,864	184,881	223,983	121.1%
Natural gas liquids (Bbl)	285,907	—	285,907	—%
Natural gas equivalents (Mcfe)	13,236,403	2,651,709	10,584,694	399.2%

For 2007, sales volumes increased approximately 400% compared to production in 2006. On a daily basis we produced an average of 36,264 *Mcfe* in 2007 compared to an average of 7,265 *Mcfe* in 2006.

	2007	2006	Change	Percent Change
Realized prices (net of hedges):				
Natural gas (Mcf)	$ 7.48	$ 6.85	$ 0.63	9.2%
Crude oil (Bbl)	66.09	59.00	7.09	12.0%
Natural gas liquids (Bbl)	49.92	—	49.92	—%
Natural gas equivalents (Mcfe)	8.25	8.10	0.15	1.9%

	2007	2006	Change	Percent Change
Prices before effects of hedges:				
Natural gas (Mcf)	$ 6.78	$ 6.76	$ 0.02	0.3%
Crude oil (Bbl)	74.38	63.29	11.09	17.5%
Natural gas liquids (Bbl)	49.92	—	49.92	—%
Natural gas equivalents (Mcfe)	8.02	8.34	(0.32)	-3.8%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. No natural gas liquids were sold in 2006. We realized a loss of $3.4 million on our crude oil hedges and a gain of $6.4 million on our natural gas hedges in 2007 compared to a realized loss of $0.8 million for crude oil hedges and a realized gain of $0.2 million for natural gas hedges in 2006.

Operating Overhead and Other Income. Revenues from *working interest* partners increased to $0.4 million in 2007 compared to $0.2 million in 2006 due to the increase in administrative overhead fees charged to partners on the operated acquired STGC Properties.

Costs and Expenses

	2007	2006	Change	Percent Change
Operating Expenses:		(in millions, except percentages)		
Lease operating expenses	$ 12.0	$ 5.6	$ 6.4	114.3%
Production and ad valorem taxes	11.7	1.9	9.8	515.8%
Exploration expenses	3.2	0.7	2.5	357.1%
Depreciation, depletion & amortization	30.8	4.0	26.8	670.0%
General and administrative expenses	14.5	8.7	5.8	66.7%
Total operating expenses	$ 72.2	$ 20.9	$ 51.3	245.5%

	2007	2006	Change	Percent Change
Selected Costs ($ per Mcfe):				
Lease operating expenses	$ 0.91	$ 2.12	$ (1.21)	-57.1%
Production and ad valorem taxes	$ 0.88	$ 0.71	$ 0.17	23.9%
Exploration expenses	$ 0.24	$ 0.25	$ (0.01)	-4.0%
Depreciation, depletion & amortization	$ 2.33	$ 1.52	$ 0.81	53.3%
General and administrative expenses	$ 1.10	$ 3.29	$ (2.19)	-66.6%

Lease Operating Expenses. Lease operating expenses for 2007 were $12.0 million, compared to $5.6 million in 2006. The increase was primarily due to the addition of the STGC Properties.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2007 were $11.7 million, compared to $1.9 million in 2006. The increase in production and ad valorem tax expenses was primarily due to the significant increase in production related to the acquisition of the STGC properties.

Exploration Expenses. Total exploration expenses were $3.2 million in 2007 compared to $0.7 million in 2006. Exploration expenses increased primarily as a result of the acquisition of the STGC properties.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense for 2007 was $30.8 million compared to $4.0 million in 2006, as a result of our acquisition of the STGC Properties.

Impairment of Oil and Gas Properties. Impairment expense was $4.4 million in 2007, primarily related to impairments on our Turkey Creek and Huff McFaddin properties, and $3.1 million in 2006, primarily related to our Iola property. Declining performance and lower gas prices at year end were contributing factors in these property impairments.

General and Administrative ("G&A") Expenses. Our G&A expenses were $14.5 million in 2007 compared to $8.7 million in 2006. Included in G&A expense is non-cash stock expense of $4.7 million ($0.32 per *Mcfe*) and $3.8 million ($1.39 per *Mcfe*) for 2007 and 2006, respectively. The $5.8 million increase was primarily due to higher personnel costs, information technology costs, professional fees and office rent incurred in expanding our infrastructure after the acquisition of the STGC Properties.

Interest Expense. Interest expense was $14.9 million in 2007, up from $0.1 million in 2006. Total interest increased to $16.2 million for 2007 because of the higher outstanding balances on our credit facilities related to the STGC Properties acquisition. However, $1.3 million of that interest, which was related to our Madisonville/Rodessa *Prospect*, was capitalized in 2007.

Other Financing Costs. Other financing costs were $1.3 million in 2007 compared with $0.2 million in 2006. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit facilities and to commitment fees related to the unused portion of the credit facilities.

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 swap. This non-cash unrealized loss for 2007 was $18.2 million compared with a non-cash unrealized gain of $6.1 million for 2006. This amount 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 $0.8 million in 2007 compared to net income before taxes of $3.3 million in 2006. After adjusting for permanent tax differences, we recorded an income tax benefit of $0.4 million in 2007 and an income tax expense of $1.4 million in 2006. The income tax benefit/expense was all deferred for both years.

Dividends on Preferred Stock. Dividends on preferred stock were $4.5 million in 2007 compared with $3.6 million for 2006. 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. Dividends in 2006 included $3.2 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.3 million on the Series E Preferred Stock.

Prior to the third quarter of 2007, we accumulated undeclared dividends on the Series G Preferred Stock, on a simple or non-compounded basis. During the third quarter, we were notified by the Preferred Stock Owner that they believed that certain provisions of the Certificate of Designations for the Series G Preferred Stock resulted in a compounding effect. After reviewing its interpretation, and consulting with legal counsel, we and the Preferred Stock Owner settled the dispute and agreed to calculate the accrued, undeclared and unpaid dividends on a compounded basis. This new basis for calculating the dividend accrual was documented in a clarification memo between the parties. In accordance with SFAS 154, the change in the method of calculating the accrued, undeclared dividend was a change in accounting estimate necessitated by the "new information" that became available with the written agreement between the parties in the settlement of the dispute. The net effect of the change in the accounting estimate was an increase of $0.7 million in Dividends on Preferred Stock in the Consolidated Statements of Operations for the year ended December 31, 2007, of which approximately $0.4 million was related to prior years, and $0.1 million and $0.2 million was related to the first and second quarters of 2007, respectively.

Critical Accounting Policies

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).

Depletion and Depreciation

We consider depletion and depreciation of oil and gas properties and related support equipment to be critical accounting estimates, based upon estimates of total recoverable natural gas, crude oil and natural gas liquids reserves. 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 Securities and Exchange Commission 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 over prices and costs existing at year end, 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 oil and gas 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 decreased in the near term. If decreased, 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 discussion of impairment expenses in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Asset Retirement Obligations

In 2003, we adopted the Statement of Financial Accounting Standards No. 143, "Asset Retirement Obligations" (*"SFAS 143"*) which requires us to recognize an estimated liability for the plugging and abandonment of our oil and gas 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 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 reserves 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 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 are required by SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," to 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

SEC 33-8995/34-59192. In December 2008, the SEC adopted Release No. 33-8995/34-59192, "Modernization of Oil and Gas Reporting" (*"SEC 33-8995"*). This release amends the oil and gas reporting disclosures that exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934 to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The new rules include changes for pricing used to estimate reserves; permitting disclosure of possible and probable reserves; ability to include non-traditional resources in reserves and the use of new technology for determining reserves. SEC 33-8995 is effective for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently evaluating the provisions of SEC 33-8995 and assessing the impact it may have on our financial reporting disclosures.

SFAS 161. In March 2008, the FASB issued SFAS No. 161, "Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" (*"SFAS 161"*). SFAS 161 amends and expands the disclosure requirements of SFAS No. 133 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 under SFAS No. 133 and its related interpretations; and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. We are currently evaluating the provisions of SFAS 161 and assessing the impact it may have on our financial reporting disclosures.

SFAS 141(R). In December 2007, the FASB issued a revision to SFAS 141 "Business Combinations" (*"SFAS 141(R)"*). 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, the statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. SFAS 141(R) is effective for business combination transactions for which the acquisition date is on or after the beginning of the first reporting period beginning on or after December 15, 2008. Early adoption is prohibited. We are currently evaluating the provisions of SFAS 141(R) and assessing the impact it may have on our financial statements when an applicable acquisition is consummated.

SFAS 157-2. In September 2006, the FASB issued SFAS 157 "Fair Value Measurements" (*"SFAS 157"*). We adopted SFAS 157 effective January 1, 2008 only for our financial assets and financial liabilities. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This standard provides guidance for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. The adoption of SFAS 157, as it applied to our financial assets and financial liabilities did not have a material impact on our consolidated financial statements. In February 2008, FASB issued Staff Position (*"FSP"*) No. SFAS 157-2, "Effective Date of FASB Statement No. 157" (*"FSP 157-2"*). FSP 157-2 defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, 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). An entity that has issued interim or annual financial statements reflecting the application of the measurement and disclosure provisions of SFAS 157 prior to February 12, 2008, must continue to apply all provisions of SFAS 157. We are currently evaluating the provisions of FSP 157-2 and assessing the impact it may have on our financial position, results of operations and reporting disclosures.

Commitments and Contingencies

The following table provides our best estimate of certain of our obligations as of December 31, 2008:

	Long-term debt	Interest	Operating leases	Asset retirements	Executive compensation	FIN 48 (1)
2009	$ 90,368	$ 14,848,716	$ 2,641,835	$ 1,659,371	$ 1,516,300	$ —
2010	17,352	14,848,716	1,820,471	1,031,755	1,516,300	—
2011	126,673,074	5,279,543	1,437,749	1,953,292	710,000	—
2012	150,000,000	3,864,088	1,419,933	438,172	—	—
2013	—	—	1,419,933	393,668	—	—
Thereafter	—	—	118,328	7,592,284	—	—
Total	$ 276,780,794	$ 38,841,063	$ 8,858,249	$ 13,068,542	$ 3,742,600	$ 518,219

(1) FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109" ("*FIN 48*"). We cannot predict at this time when this obligation may be required to be paid, if at all.

Liquidity and Capital Resources

At December 31, 2008, our current liabilities exceeded our current assets by approximately $37.6 million, primarily due to higher capital expenditures in the fourth quarter, and accruals for lease bonuses, property taxes and incentive compensation payable in 2009. At December 31, 2007 our current liabilities exceeded our current assets by approximately $12.4 million. At December 31, 2008, we had $73.3 million available under our credit agreements. During 2008, we generated $143.8 million in cash flow from operations compared to $69.6 million in 2007. Capital expenditures for the fourth quarter of 2008 were approximately $59.7 million, including $33.5 million for exploitation drilling and $25.5 million for leasehold acquisition, primarily related to our East Texas Haynesville Shale play. For the year 2008, our capital expenditures, exclusive of *producing property* acquisitions, totaled approximately $141.8 million, including $84.0 million for exploitation and exploration drilling and $57.8 million for leasehold acquisition and other expenditures. We believe cash flow, along with available borrowings under our credit agreements, will be sufficient to fund our daily operations, debt service and planned capital development program in 2009. Our level of exploratory capital expenditures for 2009 will be determined based on available cash flow and other appropriate sources of available capital. We believe that commodity prices will remain low and that service costs will decline during 2009, and that access to the capital markets will remain limited during the year; therefore, our capital expenditure strategy for 2009 will be to keep expenditures within internally generated cash flow and reduce debt. We currently anticipate capital expenditures to be no more than $25.0 million in 2009. We will continue to build our inventory of exploitation and exploration opportunities in our South Texas and Texas Gulf Coast assets, but will defer major capital allocation for drilling those opportunities until drilling costs decline, commodity prices rebound and/or the ability to access capital economically improves.

Credit Facilities

On May 8, 2007, we entered into a $400.0 million amended and restated credit agreement (the "*Senior Revolving Credit Agreement*") with Wells Fargo Bank, National Association, as agent, and various other banks, which amended and restated our existing senior secured revolving credit facility dated as of July 15, 2005, as amended. On May 31, 2007, the Senior Revolving Credit Agreement was amended to provide for up to a $5.0 million swing line facility. The Senior 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. The Senior Revolving Credit Agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Borrowings under the Senior Revolving Credit Agreement are subject to a borrowing base limitation based on our proved natural gas, crude oil and natural gas liquids reserves. The borrowing base was reaffirmed at $200.0 million on November 1, 2008. Our borrowing base is redetermined semi-annually and is subject to one unscheduled redetermination between scheduled redeterminations, which may lead to a decrease in our borrowing base. We expect to undergo a borrowing base redetermination under our Senior Revolving Credit Agreement in the second quarter of 2009, and again in the fourth quarter of 2009. In the event a borrowing base redetermination results in a reduction of our borrowing base, further availability to borrow under the Senior Revolving Credit Agreement could be reduced. Due to the recent and continuous decline in commodity prices, we will likely incur a reduction in our borrowing base at the next redetermination date. If a reduced borrowing base were to require debt repayments, we may be required to curtail our capital program further, sell assets or raise additional equity capital to meet our obligations. Accordingly, it may be difficult for us to consummate any debt or equity financing in the near future to meet such obligations, particularly due to the current worldwide financial and credit crises and the decline in our stock price.

In addition, on May 8, 2007, we entered into a five-year second lien credit agreement (the "*Second Lien Credit Agreement*") with Credit Suisse, as agent, which provides for term loans to be made in a single draw in an aggregate principal amount of $150.0 million. The Second Lien Credit Agreement replaced our then existing $150.0 million subordinate credit facility, which was paid off in full and terminated at closing.

The Senior Revolving Credit Agreement and the Second Lien Credit Agreement (the "*Credit Agreements*") are secured by a lien on all the assets of the Company and its active subsidiaries, as well as a security interest in the stock of all the Company's direct and indirect subsidiaries. The obligations under the Second Lien Credit Agreement are subordinate and junior to those under the Senior Revolving Credit Agreement.

The Credit Agreements include 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 Credit Agreements also contain certain financial covenants, including (a) with respect to the Senior Revolving Credit Agreement, 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, (ii) an interest coverage ratio of EBITDAX (earnings before interest, taxes, depreciation and amortization and exploration expense) to cash interest expense of at least 3.0 to 1.0 and (iii) a minimum leverage ratio of total debt to EBITDAX of 2.75 to 1.00 for the fiscal quarters ending after June 30, 2008 and (b) with respect to the Second Lien Credit Agreement, maintaining (i) a minimum leverage ratio of total debt to EBITDAX of 3.00 to 1.00 for the fiscal quarters ending after September 30, 2008 and (ii) a PV-10 Ratio (as defined in the Second Lien Credit Agreement) less than 1.50x for the period on or after January 1, 2008. EBITDAX is calculated without consideration of unrealized gains and losses related to stock derivatives accounted for under variable accounting rules or to commodity hedges. The PV-10 Ratio is the ratio of PV-10 Value (as defined) on the relevant date to Total Net Debt (as defined) on such date; provided that if the PV-10 Value calculated using only the estimated future revenues to be generated from proved developed producing reserves (the "*PDP Component*", is less than 60% of the otherwise calculated total PV-10 Value, then for purposes of calculating the PV-10 Ratio, PV-10 Value is deemed to be the quotient of the PDP Component divided by 0.60. At December 31, 2008, we were in compliance with the aforementioned covenants.

Due to declining commodity prices throughout 2008 and the first quarter of 2009 and an increased usage of borrowings under our Senior Revolving Credit Agreement for capital expenditures during the fourth quarter of 2008, we could fail to maintain compliance with one or more of our covenants under our Credit Agreements during 2009 and possibly as early as of the end of the first quarter of 2009. Failure to maintain compliance with these covenants as of the end of any fiscal quarter would be an event of default under either Credit Agreement and would also cause a default under the other Credit Agreement as a result of the cross-default provisions contained in our Credit Agreements. The occurrence of an event of default under either Credit Agreement for this or any other reason would permit participating banks to restrict our ability to access the revolving facility under our Senior Revolving Credit Agreement and could accelerate repayment of any outstanding amounts under the Credit Agreements, unless waived by our lenders or those provisions are amended.

During 2009 we intend to limit our capital expenditures and use a portion of our cash flow from operations to pay down outstanding debt under our Senior Revolving Credit Agreement to reduce the risk that we may fall out of compliance with these covenants in future periods. However, there can be no assurance that we will be able to successfully execute this strategy or, if executed, that it will be sufficient to avoid an event of default under our Credit Agreements during 2009 and possibly as early as of the end of the first quarter of 2009, particularly if economic or market conditions continue to deteriorate or commodity prices do not improve. See "We have a substantial amount of indebtedness, a major portion of which is contingent upon semi-annual redeterminations of a borrowing base that determines the maximum amount that can be borrowed under our senior revolving credit facility. If an event of default occurs under either of our credit facilities, all of our indebtedness may become due and payable, which may adversely affect our cash flow and our ability to operate our business," in "Item 1A. Risk Factors."

In December 2008, we settled our then existing interest rate swap by entering into two new interest rate swap agreements with Wells Fargo Bank, N.A. The base LIBOR rate on $50.0 million is constructively fixed at 1.50% until December 23, 2010, and the base LIBOR rate on $150.0 million is constructively fixed at 2.90% until May 8, 2011, effectively resetting our base LIBOR rate from 5.02% to 2.6%.

At March 25, 2009, we had $161.5 million outstanding under the Senior Revolving Credit Agreement and $150.0 million outstanding under the Second Lien Credit Agreement, with availability under the Senior Revolving Credit Agreement of $38.5 million.

We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our senior and subordinate revolving credit facilities to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies and anticipated capital expenditures.

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 received 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
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	6.78
2006				
First	$ 7.71	$ 58.11	$ —	$ 8.63
Second	6.61	60.48	—	8.09
Third	6.72	60.85	—	8.07
Fourth	6.56	56.71	—	7.71

(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 7A. Qualitative and Quantitative Disclosures about Market Risk

The following market rate disclosures should be read in conjunction with our financial statements and notes thereto beginning on Page F-1 of this Annual Report on Form 10-K. All of our financial instruments are for purposes other than trading. Hypothetical changes in interest rates and prices chosen for the following stimulated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not be an indicator of probable future fluctuations. See Note 7 - "Derivative Instruments" for further information.

Interest Rate Risk

We are exposed to interest rate risk on debt with variable interest rates. To manage this risk, we have entered into interest rate swap agreements with a total notional amount of $200.0 million related to our Senior Revolving Credit Agreement. As of December 31, 2008, the interest rate swaps had an estimated net fair value liability of $5.7 million. Under these agreements, we receive interest at a floating rate equal to one-month LIBOR and pay interest at a fixed rate of 1.50% on $50.0 million in outstanding debt and pay interest at 2.90% on $150.0 million in outstanding debt, effectively setting our base LIBOR rate at 2.6%. Assuming our current level of borrowings and considering the effect of the interest rate swap agreements, a 100 basis point increase in the interest rate we pay under our credit facility would not have had a material impact on our interest expense for the year ended December 31, 2008.

Commodity Price Risk

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, crude oil and natural gas liquids 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. 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 provide only partial protection against declines in commodity prices. Such arrangements may expose us to risk of financial loss in certain circumstances. We expect that the monthly volume of derivative arrangements will vary from time to time. We continuously reevaluate our price hedging program in light of increases in production, market conditions, commodity price forecasts, capital spending and debt service requirements.

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, 2008, 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, 2008 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, 2008.

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, 2008.

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, 2008.

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, 2008.

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, 2008.

GLOSSARY OF INDUSTRY TERMS AND ABBREVIATIONS

The following are definitions of certain industry terms and abbreviations used in this report:

Bcfe. Billions of Cubic Feet Equivalent

Bbl. Barrel.

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

Horizontal Drilling. High angle directional drilling with lateral penetration of one or more productive reservoirs.

Mcf. One thousand cubic feet.

Mcfe. Natural gas equivalent. One barrel of crude oil or natural gas liquids is equivalent to six Mcf.

NGL. *Natural gas liquids*. Natural gas liquids are a component of natural gas and include ethane, propane, butane, isobutane and natural gas. These liquids are used as petrochemical feedstocks, home heating fuels and refinery blending and are measured in barrels (Bbls).

Net Acres or *Net Wells*. The sum of the fractional working interests owned in gross acres or gross wells.

Overriding Royalty Interest. The right to receive a share of the proceeds of production from a well, free of all costs and expenses, except transportation.

Present Value. The pre-tax present value, discounted at 10%, of future net cash flows from estimated proved reserves, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the SEC's rules for inclusion of natural gas, crude oil and natural gas liquids reserve information in financial statements filed with the SEC.

Proceeds of Production. Money received (usually monthly) from the sale of natural gas, crude oil and natural gas liquids produced from producing properties.

Producing Properties. Properties that contain one or more wells that produce natural gas and/or crude oil in paying quantities (i.e., a well for which proceeds from production exceed operating expenses).

Productive Well. A well that is producing natural gas or crude oil that is capable of production.

Prospect. A lease or group of leases containing possible reserves, capable of producing natural gas, crude oil, or natural gas liquids in commercial quantities, either at the time of acquisition, or after vertical or horizontal drilling, completion of workovers, recompletions, or operational modifications.

Proved Reserves. Estimated quantities of natural gas, crude oil, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions; i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if either actual production or a conclusive formation test supports economic production.

The area of a reservoir considered proved includes:

a. That portion delineated by drilling and defined by gas-crude oil or crude 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.

Proved Reserves do not include:

a. Crude oil that may become available from known reservoirs but is classified separately as “indicated additional reserves”;

b. Natural gas, crude oil 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. Natural gas, crude oil and natural gas liquids that may occur in undrilled prospects; and

d. Natural gas, crude oil and natural gas liquids that may be recovered from sales and other sources.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional natural gas, crude oil and natural gas liquids 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 only after testing by a pilot project or after operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other units that have not been drilled 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 proven effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has previously been completed.

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

Royalty. The right to a share of production from a well, free of all costs and expenses, except transportation.

Royalty Interest. An interest in a natural gas and crude oil property entitling the owner to a share of natural gas, crude oil and natural gas liquids production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves, after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the SEC’s rules for inclusion of natural gas, crude oil and natural gas liquids reserve information in financial statements filed with the SEC.

Waterflood. An engineered, planned effort to inject water into an existing crude oil reservoir with the intent of increasing crude oil reserve recovery and production rates.

Working Interest. The operating interest under a lease, the owner of which has the right to explore for and produce natural gas, crude oil and natural gas liquids covered by such lease. The full working interest bears 100 percent of the costs of exploration, development, production and operation, and is entitled to the portion of gross revenue from the proceeds of production which remains after proceeds allocable to royalty and overriding royalty interests or other lease burdens have been deducted.

Workover. Rig work performed to restore an existing well to production or improve its production from the current existing reservoir.

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, 2008 and 2007
Consolidated Statements of Operations for the years ended December 31, 2008, 2007 and 2006
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2008, 2007 and 2006
Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006
Notes to Consolidated Financial Statements

(2) Financial Statement Schedule:

Schedule II - Valuation and Qualifying Accounts

(3) Exhibits:

Number	Description
2.1	Agreement and Plan of Merger, dated March 14, 2006, among Crimson Exploration, Inc., Exploration Operating, Inc., Core Natural Resources, Inc. and its stockholders (incorporated by reference to Exhibit 2.1 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005)
2.2	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 of the Company's Current Report on Form 8-K filed May 15, 2007)
2.3	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 of 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 3.1 of 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 3.2 of the Company's Current Report on Form 8-K filed July 5, 2005)
3.3	Certificate of Designation, Preferences and Rights of Cumulative Convertible Preferred Stock, Series E (incorporated by reference to Exhibit 3.3 of 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 3.4 of 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 3.5 of the Company's Current Report on Form 8-K filed July 5, 2005.)

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

3.6	Bylaws of the Registrant (incorporated by reference to Exhibit 3.6 of 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)
4.1	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 of the Company's Current Report on Form 8-K filed on May 10, 2004)
4.2	Registration Rights Agreement, dated May 8, 2007, by and between Crimson Exploration Inc. and EXCO Resources, Inc. (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed May 15, 2007)
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	Registration Rights Agreement, dated March 20, 2006, among Crimson Exploration Inc. and the stockholders of Core Natural Resources, Inc. (incorporated by reference to Exhibit 4.11 of Amendment No. 1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005)
*#10.1	Amended and Restated Employment Agreement between Allan D. Keel and Crimson Exploration Inc., dated December 30, 2008
*#10.2	Amended and Restated Employment Agreement between E. Joseph Grady and Crimson Exploration Inc., dated December 31, 2008
#10.3	GulfWest Oil Company 1994 Stock Option and Compensation Plan, amended and restated as of April 1, 2001 and approved by the stockholders on May 18, 2001 (incorporated by reference to Exhibit I of the Company's Proxy Statement on Form DEF 14A, filed on April 16, 2001)
#10.4	GulfWest Energy Inc. 2004 Stock Option Incentive Plan. (incorporated by reference to Exhibit 10.4 of the Company's Annual Report on Form 10-K for the year ended December 31, 2004)
#10.5	GulfWest Energy Inc. 2005 Stock Option Incentive Plan (incorporated by reference to Exhibit 10.5 of the Company's Annual Report on Form 10-K for the year ended December 31, 2004)
#10.6	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 year ended December 31, 2005)

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

#10.7	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.3 to the Company's Form 8-K filed on July 21, 2005)
10.8	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)
10.9	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)
10.10	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 of the Company's Registration Statement No. 333-116048 on Form S-1)
*#10.11	Amended and Restated Employment Agreement between Tracy Price and Crimson Exploration Inc., dated December 30, 2008
*#10.12	Amended and Restated Employment Agreement between Tommy Atkins and Crimson Exploration Inc., dated December 29, 2008
*#10.13	Amended and Restated Employment Agreement between Jay S. Mengle and Crimson Exploration Inc., dated December 31, 2008
*#10.14	Summary terms of Director Compensation Plan
#10.15	Form of director and officer restricted stock grant (incorporated by reference to Exhibit 10.3 to the Company's Form 8-K filed on July 21, 2005)
10.16	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)
#10.17	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)
10.18	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)
10.19	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

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

*#10.20	Employment Agreement between Rusty Shepherd and Crimson Exploration Inc., dated December 31, 2008
#10.21	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).
#10.22	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 of the Company's Current Report on Form 8-K filed September 11, 2008).
#10.23	Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
#10.24	Cash Incentive Bonus Plan (incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
22.1	Subsidiaries of the Registrant (included on page 3) of this Annual Report.
*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; filed herewith.
*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; filed herewith.
*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; filed herewith.
*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; filed herewith.

* 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 27, 2009

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 27, 2009
/s/ E. Joseph Grady E. Joseph Grady	Senior Vice President and Chief Financial Officer	March 27, 2009
/s/ Terence Lynch Terence Lynch	Corporate Controller and Chief Accounting Officer	March 27, 2009
/s/ B. James Ford B. James Ford	Director	March 27, 2009
/s/ Lon McCain Lon McCain	Director	March 27, 2009
/s/ Lee B. Backsen Lee B. Backsen	Director	March 27, 2009
/s/ Adam C. Pierce Adam C. Pierce	Director	March 27, 2009

CRIMSON EXPLORATION INC.

FINANCIAL REPORT

DECEMBER 31, 2008

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, 2008. 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, 2008.

/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
Chief Accounting Officer

Houston, Texas
March 27, 2009

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 as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Houston, Texas
March 26, 2009

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS

	December 31, 2008	December 31, 2007
CURRENT ASSETS		
Cash and cash equivalents	$ —	$ 4,882,511
Accounts receivable, net of allowance	21,078,815	30,034,558
Prepaid expenses	77,293	230,870
Derivative instruments	25,191,445	198,708
Deferred tax asset, net	—	1,134,918
Total current assets	46,347,553	36,481,565
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method of accounting)	584,093,885	407,905,609
Other property and equipment	3,282,088	2,710,995
Accumulated depreciation, depletion and amortization	(138,220,237)	(54,128,002)
Total property and equipment, net	449,155,736	356,488,602
NONCURRENT ASSETS		
Deposits	104,697	94,591
Debt issuance cost, net	2,890,094	3,982,023
Deferred charges	1,324,907	1,400,000
Derivative instruments	11,722,802	—
Deferred tax asset, net	—	488,293
Total noncurrent assets	16,042,500	5,964,907
TOTAL ASSETS	$ 511,545,789	$ 398,935,074

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2008	December 31, 2007
CURRENT LIABILITIES		
Current portion of long-term debt	$ 90,368	$ 100,609
Accounts payable – trade	47,726,858	41,432,777
Income tax payable	546,944	—
Accrued liabilities	24,369,060	3,234,553
Asset retirement obligations	1,659,371	1,407,347
Derivative instruments	1,265,801	2,703,959
Deferred tax liability, net	8,331,208	—
Total current liabilities	83,989,610	48,879,245
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	276,690,426	260,064,226
Asset retirement obligations	11,409,171	6,148,144
Derivative instruments	1,491,755	12,747,019
Deferred tax liability, net	15,609,315	—
Other noncurrent liabilities	732,709	1,443,359
Total noncurrent liabilities	305,933,376	280,402,748
Total liabilities	389,922,986	329,281,993
COMMITMENTS AND CONTINGENCIES (see Note 11)		
STOCKHOLDERS' EQUITY		
Preferred stock (see Note 12)	826	832
Common stock (see Note 12)	5,808	5,128
Additional paid-in capital	95,676,875	89,507,073
Retained earnings (deficit)	26,189,888	(19,859,952)
Treasury stock (see Note 12)	(250,594)	—
Total stockholders' equity	121,622,803	69,653,081
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 511,545,789	$ 398,935,074

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,		
	2008	2007	2006
OPERATING REVENUES			
Natural gas sales	$ 116,414,956	$ 67,867,605	$ 10,569,705
Crude oil sales	41,860,385	27,021,296	10,908,030
Natural gas liquids sales	27,404,774	14,272,712	—
Operating overhead and other income	1,088,158	381,595	181,746
Total operating revenues	186,768,273	109,543,208	21,659,481
OPERATING EXPENSES			
Lease operating expenses	20,824,629	12,033,963	5,633,069
Production and ad valorem taxes	16,266,493	11,701,908	1,894,520
Exploration expenses	9,965,372	3,174,415	673,015
Depreciation, depletion and amortization	50,466,966	30,796,487	4,035,452
Impaired assets of oil and gas properties	35,953,586	4,362,186	3,149,980
General and administrative	22,405,639	14,541,780	8,729,674
(Gain) loss on sale of assets	(15,209,706)	(683,830)	2,456
Total operating expenses	140,672,979	75,926,909	24,118,166
INCOME (LOSS) FROM OPERATIONS	46,095,294	33,616,299	(2,458,685)
OTHER INCOME (EXPENSE)			
Interest expense, net of amount capitalized	(21,108,603)	(14,949,358)	(108,961)
Other financing costs	(1,501,627)	(1,321,661)	(228,320)
Loss from equity in investments	—	—	(1,843)
Unrealized gain (loss) on derivative instruments	49,408,961	(18,186,158)	6,082,058
Total other income (expense)	26,798,731	(34,457,177)	5,742,934
INCOME (LOSS) BEFORE INCOME TAXES	72,894,025	(840,878)	3,284,249
Income Tax (Expense) Benefit	(26,690,807)	410,361	(1,425,305)
NET INCOME (LOSS)	46,203,218	(430,517)	1,858,944
Dividends on Preferred Stock (Paid 2008-$153,378; 2007-$702,948; 2006-$154,875)	(4,234,050)	(4,453,872)	(3,648,925)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 41,969,168	$ (4,884,389)	$ (1,789,981)
NET INCOME (LOSS) PER SHARE			
Basic	$ 7.81	$ (1.13)	$ (0.55)
Diluted	$ 4.46	$ (1.13)	$ (0.55)
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	5,371,377	4,330,282	3,231,000
Diluted	10,360,348	4,330,282	3,231,000

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, 2008, 2007 and 2006

	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, 2005	103,250	2,899,182	$ 1,033	$ 2,899	$ 72,877,718	$ (20,076,388)	$ —	$ 52,805,262
Share-based compensation	—	28,644	—	29	3,876,985	—	—	3,877,014
Stock options exercised	—	10,700	—	11	48,139	—	—	48,150
Preferred H converted	(30)	4,287	(1)	4	(3)	—	—	—
Acquisition of oil and gas leases	—	369,789	—	370	2,736,043	—	—	2,736,413
Current year net income	—	—	—	—	—	1,858,944	—	1,858,944
Dividends paid on preferred stock	—	21,000	—	21	154,854	(154,875)	—	—
BALANCE, DECEMBER 31, 2006	103,220	3,333,602	1,032	3,334	79,693,736	(18,372,319)	—	61,325,783
Cumulative effect of adopting FIN 48	—	—	—	—	—	(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
Current year net loss	—	—	—	—	—	(430,517)	—	(430,517)
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
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)	—	—	—
Current year net income	—	—	—	—	—	46,203,218	—	46,203,218
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

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,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 46,203,218	$ (430,517)	$ 1,858,944
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	50,466,966	30,796,487	4,035,452
Asset retirement obligations	(546,840)	(268,445)	(14,113)
Stock compensation expense	5,434,992	4,738,125	3,819,600
Debt issuance cost	1,091,929	1,059,033	134,131
Deferred charges	75,093	(1,400,000)	—
Income taxes (current and deferred)	26,110,678	(410,361)	1,425,305
Dry holes, abandoned property, impaired assets	43,309,365	5,710,125	3,209,943
(Gain) loss on sale of assets	(15,209,706)	(683,830)	2,456
Loss from equity in investments	—	—	1,843
Unrealized (gain) loss on derivative instruments	(49,408,961)	18,186,158	(6,082,058)
Provision for bad debts	—	96,904	87,436
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable – trade, net	8,973,958	(22,648,152)	(161,811)
(Increase) decrease in prepaid expenses	153,577	(5,566)	24,120
Increase in accounts payable and accrued liabilities	27,114,462	34,871,687	5,946,284
Net cash provided by operating activities	143,768,731	69,611,648	14,287,532
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sale of assets	34,923,332	756,650	7,950
Acquisition of oil and gas properties	(58,481,721)	(253,434,220)	—
Capital expenditures	(141,794,612)	(59,048,764)	(21,777,332)
Deposits	(10,106)	(45,089)	—
Net cash used in investing activities	(165,363,107)	(311,771,423)	(21,769,382)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from exercise of common stock options and warrants	346,500	4,800	48,150
Purchase of treasury stock	(250,594)	—	—
Payments on debt	(132,393,063)	(68,571,595)	(18,805,206)
Proceeds from debt	149,009,022	320,177,233	26,097,334
Debt issuance expenditures	—	(4,591,473)	(309,500)
Net cash provided by financing activities	16,711,865	247,018,965	7,030,778
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(4,882,511)	4,859,190	(451,072)
CASH AND CASH EQUIVALENTS, Beginning of year	4,882,511	23,321	474,393
CASH AND CASH EQUIVALENTS, End of year	$ —	$ 4,882,511	$ 23,321
Cash Paid For Interest	$ 22,484,711	$ 14,914,194	$ 291,163
Cash Paid For Income Taxes	$ 580,129	$ —	$ 31,000
Non-Cash Stock Issuance For Oil And Gas Properties	$ —	$ 4,575,000	$ 2,736,413

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, development, exploitation and production of crude oil, natural gas and natural gas liquids, principally in the onshore gulf coast regions of Texas and Louisiana and in Colorado.

Organization

In June 2005, our predecessor, GulfWest Energy Inc., a Texas corporation (*"GulfWest"*), merged with and into Crimson Exploration Inc., a Delaware corporation (*"Crimson"*), for the purpose of changing our state of incorporation from Texas to Delaware (*"Reincorporation"*). The Reincorporation was accomplished pursuant to an Agreement and Plan of Merger, dated June 28, 2005, which was approved by GulfWest's stockholders at the 2005 Annual Stockholders' Meeting held June 1, 2005.

In January 2006, we formed Crimson Exploration Operating, Inc. (*"CEO"*), a Delaware corporation, as our wholly owned subsidiary through which all operations are conducted. Effective March 2, 2006, we merged all our subsidiaries, with the exception of LTW Pipeline Co., into this newly formed corporation. LTW Pipeline Co. remains an inactive subsidiary of Crimson Exploration Inc.

In September 2006, we effected a reverse stock split where each ten shares of outstanding common stock were exchanged for one new share of common stock. All periods presented have been adjusted to reflect the effects of the reverse stock split.

On May 8, 2007, CEO acquired certain natural gas and crude oil properties and related assets in the South Texas and Gulf Coast areas of Louisiana and Texas ("*STGC Properties*") pursuant to a Membership Interest Purchase and Sale Agreement ("*Purchase Agreement*") from EXCO Resources, Inc. ("*EXCO*") through the acquisition of 100% of the membership interest of Southern G Holdings, LLC ("*SGH*"). These properties were operated under SGH until SGH merged with CEO on December 31, 2007. The consolidated statements of operations include the results of operations of the STGC Properties from May to present.

Segments

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.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation, including a breakout of sales by commodity, a breakout of production and ad valorem taxes from lease operating expenses and a reclassification of asset retirement obligations. We reclassified accretion expense from asset retirement obligations to depreciation, depletion and amortization. We also reclassified net settled asset retirement obligations expense from asset retirement obligations to exploration expenses. All of these reclassifications were made based on the materiality of these items to the Consolidated Statements of Operations. These changes had no impact on Total Operating Revenues, Income (Loss) from Operations or Net Income (Loss) as previously disclosed.

2. Summary of Significant Accounting Policies

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. 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, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depleted by the unit-of-production method.

On the sale of an entire interest in an unproved property, the gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property has been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. On the sale of an entire or partial interest in a proved property, the gain or loss is recognized, based upon the fair values of the interests sold and retained.

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 with no provision for price and cost escalations over prices and costs existing at year end 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 which are in progress qualify for interest capitalization. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt 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 totaled $0.9 million, $1.3 million and $0.2 million in 2008, 2007 and 2006 respectively.

Asset Retirement Obligations

In 2003, we adopted the Statement of Financial Accounting Standards (*"SFAS"*) No. 143, "Asset Retirement Obligations" (*"SFAS 143"*) which requires us to 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.

Other Property and Equipment

The following tables set forth certain information with respect to our other property and equipment. With the exception of leasehold improvements, which is amortized over the term of the lease, other property and equipment is recorded at cost, and we provide for depreciation and amortization using the straight-line method over the following estimated useful lives of the respective assets:

Assets	Years
Automobiles	3-5
Office equipment	7
Computer software	7
Gathering system	10
Well servicing equipment	10

Capitalized costs relating to other properties and equipment are as follows:

	2008	2007
Automobiles	$ 359,466	$ 407,894
Office equipment	971,173	604,670
Computer software	880,713	742,019
Leasehold improvements	695,688	581,364
Gathering system	271,651	271,651
Well servicing equipment	103,397	103,397
	3,282,088	2,710,995
Less accumulated depreciation	(1,246,427)	(913,157)
Net capitalized cost	$ 2,035,661	$ 1,797,838

Impairments

We have adopted SFAS 144 "Accounting for the Impairment or Disposal of Long- Lived Assets." Accordingly, 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.

Revenue Recognition and Oil and Gas Imbalances

The Company follows the "sales" (takes or cash) 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 (one month for operated properties, two 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, 2008 and 2007 was $215,015.

Fair Value Measurements

We adopted SFAS No. 157, "Fair Value Measurements" (*"SFAS 157"*), as of January 1, 2008 as related to our financial assets and liabilities. SFAS 157 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. Under the standard, additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. As a result of adoption, we began incorporating a credit risk assumption into the measurement of certain assets and liabilities. Adoption of SFAS 157 did not have a significant impact on our consolidated financial statements. See Note 5 – "Fair Values of Financial Instruments" for further information.

We also adopted SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (*"SFAS 159"*) as of January 1, 2008. SFAS No. 159 provides companies with an option to report selected financial assets and liabilities at fair value. Adoption had no effect on our financial position or results of operations as we made no elections to report selected financial assets or liabilities at fair value.

Debt Issuance Costs

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

Earnings (Loss) Per Share

We have adopted Statement of Financial Accounting Standards No. 128 "Earnings Per Share" (*"SFAS 128"*), which requires that both basic earnings (loss) per share and diluted earnings (loss) per share be presented on the face of the statement of operations. Basic earnings (loss) per share are based on the weighted-average number of outstanding common shares. Diluted earnings (loss) per-share is 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 adopted SFAS No. 123R "Share-Based Payment" (*"SFAS 123(R)"*) as of January 1, 2006. SFAS 123(R) revised SFAS 123, "Accounting for Stock-Based Compensation" and nullified Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and its related implementation guidance. SFAS 123(R) requires companies to 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.

In accordance with SFAS 123(R) 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 and new employees. See Note 13 – “Share-Based Compensation” for further information.

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. 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. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions.

Recent Accounting Pronouncements

SEC 33-8995/34-59192. In December 2008, the SEC adopted Release No. 33-8995/34-59192, “Modernization of Oil and Gas Reporting” (*“SEC 33-8995”*). This release amends the oil and gas reporting disclosures that exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934 to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The new rules include changes for pricing used to estimate reserves; permitting disclosure of possible and probable reserves; ability to include non-traditional resources in reserves and the use of new technology for determining reserves. SEC 33-8995 is effective for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently evaluating the provisions of SEC 33-8995 and assessing the impact it may have on our financial reporting disclosures.

SFAS 161. In March 2008, the FASB issued SFAS No. 161, “Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133” (*“SFAS 161”*). SFAS 161 amends and expands the disclosure requirements of SFAS No. 133 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 under SFAS No. 133 and its related interpretations; and (iii) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. We are currently evaluating the provisions of SFAS 161 and assessing the impact it may have on our financial reporting disclosures.

SFAS 141(R). In December 2007, the FASB issued a revision to SFAS 141 “Business Combinations” (*“SFAS 141(R)*”). 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, the statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. SFAS 141(R) is effective for business combination transactions for which the acquisition date is on or after the beginning of the first reporting period beginning on or after December 15, 2008. Early adoption is prohibited. We are currently evaluating the provisions of SFAS 141(R) and assessing the impact it may have on our financial statements when an applicable acquisition is consummated.

SFAS 157-2. In September 2006, the FASB issued SFAS 157. In February 2008, FASB issued Staff Position (*“FSP”*) No. SFAS 157-2, “Effective Date of FASB Statement No. 157” (*“FSP 157-2”*). FSP 157-2 defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, 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). An entity that has issued interim or annual financial statements reflecting the application of the measurement and disclosure provisions of SFAS 157 prior to February 12, 2008, must continue to apply all provisions of SFAS 157. We are currently evaluating the provisions of FSP 157-2 and assessing the impact it may have on our financial position, results of operations and reporting disclosures.

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:

	2008	2007
Unproved oil and gas properties	$ 68,278,373	$ 35,059,298
Proved oil and gas properties	489,069,881	361,582,956
Wells and related equipment and facilities	26,745,631	11,263,355
	584,093,885	407,905,609
Less accumulated depreciation, depletion and amortization	(136,973,810)	(53,214,845)
Net capitalized costs	$ 447,120,075	$ 354,690,764

The following table sets forth the composition of exploration expenses:

	2008	2007	2006
Dry holes	$ —	$ 605,561 (1)	$ —
Lease rental expense	172,384	242,103	220,110
Geological and geophysical	1,692,102	1,430,046	223,386
Settled asset retirement obligations	745,107	69,325	161,520
Abandoned property	7,355,779 (2)	827,380	67,999
	$ 9,965,372	$ 3,174,415	$ 673,015

(1) Mustang Island was reclassified from impairment to a dry hole.
(2) In November 2008, we released 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:

	2008	2007	2006
Property Acquisitions			
Proved	$ 60,765,315	$ 238,036,360	$ —
Unproved	57,203,337	30,407,525	8,745,363
Development Costs	86,685,192	30,814,788	6,465,719
Exploration Costs	2,520,389	13,405,017	10,783,663
	$ 207,174,233	$ 312,663,690	$ 25,994,745

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 and geological and geophysical expenses.

The following table shows oil and gas property dispositions:

	2008	2007	2006
Oil and gas properties	$ 21,765,688	$ —	$ —
Accumulated depreciation, depletion and amortization	(1,659,588)	—	—
Net oil and gas properties	$ 20,106,100	$ —	$ —

The dispositions in 2008 resulted in a net gain of $15.2 million.

4. Acquisitions and Disposition of Oil and Gas Properties

Acquisition from Smith Production Inc.

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 effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.0 million for the period between the effective date and the closing date, the cash consideration was $58.0 million, subject to final adjustment, by the end of the first quarter of 2009. The assets acquired consist of a 25% non-operated working interest in Samano Field located in Starr and Hidalgo counties, a 100% operated working interest in North Bob West Field in Zapata County and 100% operated working interests in 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.

The $58.0 million adjusted price, with adjustment to the reserves for approximately one Bcfe of production for the interim operations between the effective date and closing, represented a purchase cost of $2.82 per Mcf*e* 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 the senior revolving credit facility.

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.

Prospect Acquisitions

During the third and fourth quarters of 2008, we acquired approximately 11,876 net undeveloped acres in Sabine, Shelby and San Augustine counties in Texas on which we will target the Haynesville Shale, James Lime, and Travis Peak formations. We are currently developing a drilling strategy for this acreage, including unit and well spacing, with the expectation that we will commence our first well during the third quarter of 2009. We intend to continue to acquire additional acreage that complements our existing position and expect to have an active drilling program in this area by mid-year 2010. We financed this acquisition with cash flows from operations and from borrowings available under the senior credit facility.

Fort Worth Barnet 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 final 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 senior revolving credit facility and to help finance our acquisition of the properties from Smith. Our net book value of these 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 years ended December 31, 2007 and 2006 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, 2006. 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 Years Ended December 31, 2007	For the Years Ended December 31, 2006
	(unaudited) (in thousands, except share amounts)	
Pro forma:		
Operating revenues	$ 154,068	$ 206,909
Income from operations	$ 56,647	$ 109,677
Net income	$ 9,305	$ 60,538
Basic earnings per share	$ 1.06	$ 14.29
Diluted earnings per share	$ 0.95	$ 6.33

5. Fair Values of Financial Instruments

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, 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. We value our derivative instruments utilizing estimates of present value as calculated by the respective counter-party financial institutions and reviewed by management. See Note 7 – "Derivative Instruments" 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, 2008:

	Total Carrying Value	Fair Value Measurements Using Level 1	Level 2	Level 3
Derivatives				
Crude oil & natural gas swaps	$ 2,927,972	—	$ 2,927,972	—
Crude oil & natural gas collars	36,914,245	—	36,914,245	—
Interest rate swaps	(5,685,526)	—	(5,685,526)	—
	$ 34,156,691		$ 34,156,691	

SFAS 157, which we adopted as of January 1, 2008, establishes 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. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

Debt –The fair value of floating-rate debt is estimated using the 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.

6. Impairments

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.

Impairment expense was $4.4 million in 2007, primarily related to our Turkey Creek and Huff McFaddin properties, and $3.1 million in 2006, primarily related to our Iola property. Declining performance and lower gas prices at year end were contributing factors in these property impairments.

7. Derivative Instruments

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. 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. 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 and debt service requirements.

We used a mix of swaps and costless collars to accomplish our hedging strategy. We also constructively fixed the base LIBOR rate on $200.0 million of our variable rate debt by entering into interest rate swaps agreements.

The following derivative contracts were in place at December 31, 2008:

Crude Oil		Volume/Month	Price/Unit	Fair Value
Jan 2009-Dec 2009	Swap	5,200 Bbls	$74.20	$ 1,224,731
Jan 2009-Dec 2009	Collar	12,800 Bbls	Floor $66.55-$71.40 Ceiling	2,011,268
Jan 2009-Dec 2009	Collar	10,646 Bbls	Floor $115.00-$171.50 Ceiling	7,784,669
Jan 2010-Dec 2010	Swap	4,250 Bbls	$72.32	422,097
Jan 2010-Dec 2010	Collar	9,000 Bbls	Floor $65.28-$70.60 Ceiling	366,711
Jan 2010-Dec 2010	Collar	7,604 Bbls	Floor $110.00-$181.25 Ceiling	4,337,646
Jan 2011-Dec 2011	Swap	3,300 Bbls	$70.74	73,308
Jan 2011-Dec 2011	Collar	7,000 Bbls	Floor $64.50-$69.50 Ceiling	(159,439)
Natural Gas		**Volume/Month**	**Price/Unit**	
Jan 2009-Dec 2009	Swap	36,000 Mmbtu	$8.32	950,951
Jan 2009-Dec 2009	Collar	475,000 Mmbtu	Floor $7.90-$9.45 Ceiling	11,130,013
Jan 2009-Dec 2009	Collar	100,375 Mmbtu	Floor $9.50-$18.70 Ceiling	4,265,493
Jan 2010-Dec 2010	Swap	29,000 Mmbtu	$7.88	256,885
Jan 2010-Dec 2010	Collar	351,000 Mmbtu	Floor $7.57-$9.05 Ceiling	3,432,247
Jan 2010-Dec 2010	Collar	85,167 Mmbtu	Floor $9.00-$15.25 Ceiling	2,395,846
Jan 2011-Dec 2011	Collar	266,000 Mmbtu	Floor $7.32-$8.70 Ceiling	1,349,791
Interest rate		**Notional Amount**	**Fixed LIBOR Rate**	
Jan 2009 – Dec 2010	Swap	$50,000,000	1.50%	(289,496)
Jan 2009 – May 2011	Swap	$150,000,000	2.90%	(5,396,030)
			Total net fair value asset of derivative instruments	$ 34,156,691

The total net fair value asset for derivative instruments at December 31, 2008 was $34.2 million, and the total net fair value liability at December 31, 2007 was $15.3 million. As a result of these agreements, we recorded a non-cash unrealized gain, for unsettled contracts, of $49.4 million for the twelve months ended December 31, 2008, a non-cash unrealized loss of $18.2 million for the twelve months ended December 31, 2007. The estimated change in fair value of the derivatives is reported in “Other Income (Expense)” as unrealized gain (loss) on derivative instruments.

For natural gas and crude oil derivatives settled during 2008, we realized losses, reflected in operating revenues, of $9.3 million for the twelve months ended December 31, 2008. For natural gas and crude oil derivatives settled during 2007, we realized gains of $3.0 million for the twelve months ended December 31, 2007 and a non-cash unrealized gain of $6.1 million for the twelve months ended December 31, 2006. For natural gas and crude oil derivatives settled during 2006, we realized losses, reflected in operating revenues of $0.6 million for the twelve months ended December 31, 2006. For interest rate swaps, we realized losses, included in interest expense, of $4.0 million for the twelve months ended December 31, 2008. We realized gains, included in interest expense, of $0.2 million from interest rate swaps for the twelve months ended December 31, 2007.

8. Accrued Liabilities

Accrued liabilities consist of the following:

	December 31, 2008	December 31, 2007
Lease acquisition costs	$ 11,246,914	$ —
Capital drilling and operating costs	9,202,949	—
Smith acquisition	1,291,847	—
Accrued compensation	1,244,772	1,486,116
Interest and loan fees	988,521	1,530,627
Other	394,057	217,810
	$ 24,369,060	$ 3,234,553

9. Asset Retirement Obligations

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

	December 31,	
	2008	2007
Balance beginning of year	$ 7,555,491	$ 4,215,205
Accretion expense	620,813	435,328
Liabilities incurred	4,191,364	3,184,079
Liabilities settled	(853,867)	(279,121)
Revisions	1,554,741	—
Balance end of year	$ 13,068,542	$ 7,555,491

During 2008, we recognized additional liabilities incurred 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 amended and restated credit agreement (the "*Senior Revolving Credit Agreement"*) with Wells Fargo Bank, National Association, as agent, and various other banks, which amended and restated our then existing senior secured revolving credit facility dated July 15, 2005, as amended. On May 31, 2007, the Senior Revolving Credit Agreement was amended to provide for up to a $5.0 million swing line facility. The Senior 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. The Senior Revolving Credit Agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Borrowings under the Senior Revolving Credit Agreement are subject to a borrowing base limitation based on our proved natural gas, crude oil and natural gas liquids reserves. The borrowing base was reaffirmed at $200.0 million on November 1, 2008. Our borrowing base is redetermined semi-annually and is subject to one unscheduled redetermination between scheduled redeterminations, which may lead to a decrease in our borrowing base. We expect to undergo a borrowing base redetermination under our Senior Revolving Credit Agreement in the second quarter of 2009, and again in the fourth quarter of 2009. In the event a borrowing base redetermination results in a reduction of our borrowing base, further availability to borrow under the Senior Revolving Credit Agreement could be reduced. Due to the recent and continuous decline in commodity prices, we will likely incur a reduction in our borrowing base at the next redetermination date. Additionally, if a reduced borrowing base requires debt repayments, we may be required to curtail our capital program further, sell assets or raise additional equity capital to meet our obligations. In addition, it may be difficult for us to consummate any debt or equity financing in the near future to meet such obligations, particularly due to the current worldwide financial and credit crises and the decline in our stock price.

In addition, on May 8, 2007, we entered into a second lien credit agreement (the "*Second Lien Credit Agreement*") with Credit Suisse, as agent, which provides for term loans to be made to us in a single draw in an aggregate principal amount of $150.0 million. The Second Lien Credit Agreement replaced our then existing $150.0 million subordinate credit facility, which was paid off in full and terminated at closing. The Second Lien Credit Agreement has a term of five years and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2012.

The Senior Revolving Credit Agreement and the Second Lien Credit Agreement ("the *Credit Agreements*") are secured by a lien on substantially all of our assets, as well as a security interest in the stock of our subsidiaries. The obligations under the Second Lien Credit Agreement are subordinate and junior to those under the Senior Revolving Credit Agreement. Interest is payable on the Credit Agreements as borrowings mature and renew.

The Credit Agreements include 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 Credit Agreements also contain certain financial covenants, including (a) with respect to the Senior Revolving Credit Agreement, 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, (ii) an interest coverage ratio of EBITDAX (earnings before interest, taxes, depreciation and amortization and exploration expense) to cash interest expense of at least 3.0 to 1.0 and (iii) a minimum leverage ratio of total debt to EBITDAX of 2.75 to 1.00 for the fiscal quarters ending after June 30, 2008 and (b) with respect to the Second Lien Credit Agreement, maintaining (i) a minimum leverage ratio of total debt to EBITDAX of 3.00 to 1.00 for the fiscal quarters ending after September 30, 2008 and (ii) a PV-10 Ratio (as defined in the Second Lien Credit Agreement) less than 1.50x for the period on or after January 1, 2008. EBITDAX is calculated without consideration of unrealized gains and losses related to stock derivatives accounted for under variable accounting rules or to commodity hedges. The PV-10 Ratio is the ratio of PV-10 Value (as defined) on the relevant date to Total Net Debt (as defined) on such date; provided that if the PV-10 Value calculated using only the estimated future revenues to be generated from proved developed producing reserves (the "*PDP Component*", is less than 60% of the otherwise calculated total PV-10 Value, then for purposes of calculating the PV-10 Ratio, PV-10 Value is deemed to be the quotient of the PDP Component divided by 0.60. At December 31, 2008, we were in compliance with the Credit Agreements' covenants.

Our debt consists of the following:

	December 31, 2008	December 31, 2007
Subordinated promissory notes to various unlocatable individuals	$ 50,000	$ 50,000
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, 2008 per annum; secured by the related equipment; due various dates through 2010	57,720	114,835
Senior Revolving Credit Agreement with a borrowing base of $200.0 million, secured by all of our assets, interest at the higher of prime or Federal Fund rate plus a margin of 0.50%, or, at the option of the holder, LIBOR plus a margin of 1.25% to 2.00% depending on the percent of the borrowing base utilized at the time of the credit extension, due and payable in full in May 2011	126,673,074	110,000,000
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 5.75% or base rate plus 4.75%, maturing in May 2012	150,000,000	150,000,000
	276,780,794	260,164,835
Less current portion	(90,368)	(100,609)
Total long-term debt	$ 276,690,426	$ 260,064,226

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

2009	$ 90,368
2010	17,352
2011	126,673,074
2012	150,000,000
2013	—
	$ 276,780,794

11. Commitments and Contingencies

The following table provides our best estimate on certain of our obligations as of December 31, 2008:

	Long-term debt	Interest	Operating leases	Asset retirements	Executive compensation	FIN 48 (1)
2009	$ 90,368	$ 14,848,716	$ 2,641,835	$ 1,659,371	$ 1,516,300	$ —
2010	17,352	14,848,716	1,820,471	1,031,755	1,516,300	—
2011	126,673,074	5,279,543	1,437,749	1,953,292	710,000	—
2012	150,000,000	3,864,088	1,419,933	438,172	—	—
2013	—	—	1,419,933	393,668	—	—
Thereafter	—	—	118,328	7,592,284	—	—
Total	$ 276,780,794	$ 38,841,063	$ 8,858,249	$ 13,068,542	$ 3,742,600	$ 518,219

(1) FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109" ("*FIN 48*"). We are unable to determine when this obligation may be required to be paid, if at all.

Lease Obligations

We entered into a sublease agreement for new office space under an eighty-two (82) month lease that commenced in April 2007. We leased additional space in August 2008. Both leases expire in January 2014.

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 general and administrative rent expense for the years ended December 31, 2008, 2007 and 2006, were approximately $1.4 million, $0.4 million and $0.2 million, respectively. Total operational rent expense for the years ended December 31, 2008, 2007 and 2006, were approximately $3.4 million, $0.9 million and $1.0 million, respectively.

Litigation

From time to time, we are involved in litigation arising out of our operations or from disputes with vendors in the normal course of business. As of December 31, 2008, we are not currently engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material effect on our consolidated financial statements.

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

	2008	2007
Preferred Stock		
Series G, par value \$0.01; 81,000 shares authorized; 80,500 and 81,000 issued and outstanding at December 31, 2008 and 2007, respectively.	805	810
Series H, par value \$0.01; 6,500 shares authorized; 2,100 and 2,200 shares issued and outstanding at December 31, 2008 and 2007, respectively.	21	22
	\$ 826	\$ 832
Common Stock		
Par value \$0.001; 200,000,000 shares authorized; 5,787,287 and 5,127,937 shares issued as of December 31, 2008 and 2007, respectively	\$ 5,808	\$ 5,128
Treasury Stock		
At cost, 20,625 and zero shares as of December 31, 2008 and 2007, respectively	\$ (250,594)	\$ —

The 80,500 shares of our Series G Preferred Stock bear cumulative dividends of 8% per year, compounded quarterly, and have an aggregate liquidation preference of \$40.3 million, excluding accumulated and undeclared dividends. For the first four years after issuance, we may defer the payment of dividends on the Series G Preferred Stock and these deferred dividends will also be convertible into our Common Stock at \$9.00 per share. These dividends are not currently being accrued in our financial statements until such time as they are declared by the Board of Directors and become due and payable. In addition, the Series G Preferred Stock is entitled to vote on an as-converted basis with the holders of our Common Stock and, as a class, is entitled to nominate and elect a majority of the members of our Board of Directors. The Series G Preferred Stock is senior to all of our outstanding capital stock in liquidation preference.

The 2,100 shares of our Series H Preferred Stock are 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 is convertible into Common Stock at a conversion price of \$3.50 per share. The Series H Preferred Stock has an aggregate liquidation value of \$1.1 million and is senior to all of our outstanding capital stock in liquidation preference other than the Series G Preferred Stock.

All classes of preferred stockholders have a liquidation preference over common stockholders of \$500 per preferred share, plus accrued dividends. Accumulated, unpaid and undeclared dividends at December 31, 2008 were \$14.4 million (Series G \$14.4 million; Series H \$9,380). Once dividends are declared, they may be converted to approximately 1.6 million shares of Common Stock (Series G 1.6 million; Series H 2,680).

13. Share-Based Compensation

As of December 31, 2008, we had share-based compensation, which includes both stock options and restricted stock awarded to employees and directors. The following table reflects share-based compensation expense assuming a 36.5% effective tax rate for the years ended:

	December 31, 2008	December 31, 2007	December 31, 2006
Share-based compensation expense, net of tax \$1,982,984, \$1,725,277 and \$1,339,014, respectively	\$ 3,452,008	\$ 3,003,387	\$ 2,330,975
Basic income (loss) per share impact	\$ (0.64)	\$ (0.69)	\$ (0.72)
Diluted income (loss) per share impact	\$ (0.33)	\$ (0.69)	\$ (0.72)

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 are calculated as a percentage of base salary for the plan year. The plan awards are disbursed in the first quarter of the following year. Employees must be employed by us at the time that final plan awards are dispersed to be eligible.

The CIBP awards are paid out in cash (*"Cash Awards"*). The performance targets are 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 LTIP bonus awards are paid half in the form of restricted Common Stock and half in the form of stock options (*"Stock Awards"*). The Stock Awards will 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 to be granted as Stock Awards will be 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 will be determined through use of the Black-Scholes valuation model. The Stock Awards to be granted pursuant to this plan will be granted under the existing amended and restated 2005 Stock Incentive Plan. The Board of Directors and a majority of the Common Stock equivalents 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 by 1,000,000 shares.

In March 2009, the Board of Directors approved the awarding of approximately 1.1 million shares to our employees under the performance-based Long-Term Incentive Plan ("*LTIP*") for the 2008 calendar year. After the issuance of these stock awards, approximately 0.4 million stock awards will remain in the plan. Due to the recent decline in our stock price, the Board of Directors suspended the LTIP for 2009. Any share-based bonus awards for fiscal year 2009 will be awarded at the discretion of the Board of Directors.

Stock Options

Effective July 15, 2004, we implemented our 2004 Stock Option and Compensation Plan (*"2004 Plan"*). As of December 31, 2008, there were options to purchase 44,300 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 1.6 million (0.8 million vested) stock options and 0.5 million restricted shares were outstanding under this plan at December 31, 2008. Option awards outstanding under both plans have exercise prices ranging from $4.50 to $16.55 per share. At December 31, 2008, we had approximately 1.5 million shares of Common Stock available for future grant under the plan.

Pursuant to SFAS 123(R) for options issued under our 2005 plan, we recorded $5.0 million, $4.2 million and $3.7 million in expense (included in general and administrative expense on the Consolidated Statements of Operations) for the years ended December 31, 2008, 2007 and 2006, respectively, and an estimated $2.5 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 is zero and is based on historical forfeiture rates.

	2008	**2007**	**2006**
Expected volatility	58.61%	87.46%	92.33%
Risk-free rate	3.38%	4.12%	4.04%
Expected dividend yields	—%	—%	—%
Expected term (in years)	6.0	6.0	6.0

The following table summarizes stock option activity for the three years ended December 31, 2008:

	Number of Shares Underlying Options	Weighted Average Exercise Price
Outstanding at December 31, 2005	2,411,000	$ 13.60
Granted	51,000	13.12
Exercised	(10,700)	4.50
Expired	(6,500)	8.30
Forfeited	(103,000)	14.89
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
Exercisable at December 31, 2008	811,471	$ 10.78

The weighted-average grant date fair value of options granted during the years ended December 31, 2008, 2007 and 2006 was $7.07, $4.53 and $7.13, respectively. The total intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006 was approximately $0.5 million, $5,425 and $33,360 respectively. The weighted average remaining life for outstanding and exercisable stock options at December 31, 2008 was 6.9 years and 6.1 years, respectively. The aggregate intrinsic values for outstanding and exercisable stock options at December 31, 2008 were zero.

Restricted Stock Awards

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. Under SFAS 123R, 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. Under SFAS 123R, 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. In 2008, 82,500 shares of Common Stock were vested, of which 20,625 shares were acquired by us to satisfy the employees' tax liability resulting from the vesting of these shares, with the remaining shares being released to the employees. None of the awards vested in 2007. We expensed $191,406 during the year ended December 31, 2007 and $459,375 during the year ended December 31, 2008. 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. We expensed $12,796 during the year ended December 31, 2007 and expensed $7,204 during the year ended December 31, 2008.

On May 12, 2006, we issued 2,410 restricted shares of our Common Stock to our directors as compensation. The stock vested on May 12, 2007. We expensed $12,742 during the year ended December 31, 2006 and expensed $7,258 during the year ended December 31, 2007. On February 28, 2006, we also issued 26,234 restricted shares of our Common Stock to members of our management in lieu of cash bonuses. The stock vested on February 28, 2007. We expensed $163,960 during the year ended December 31, 2006, and expensed $32,790 during the year ended December 31, 2007.

We have not incurred any forfeiture related to the restricted stock awards issued.

Restricted stock activity for the three years ended December 31, 2008 is summarized below:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1, 2006	3,410	8.80
Granted	28,644	7.57
Vested	(3,410)	8.80
Non-vested as of December 31, 2006	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

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

Stock Warrants

We have issued a number of stock warrants for a variety of reasons, including compensation to employees, inducements related to the issuance of debt and for the payment of goods and services. Following is a schedule by year of the activity related to stock warrants, including weighted-average exercise prices of warrants in each category:

	2007		2006	
	Wtd Avg Prices	Number	Wtd Avg Prices	Number
Balance, January 1	$ 0.10	3,000	$ 7.40	147,000
Warrants issued	—	—	—	—
Warrants exercised or expired	0.10	(3,000)	7.50	(144,000)
Balance, December 31	$ —	—	$ 0.10	3,000

No warrants have been issued since 2005. All warrants have expired.

14. Income (Loss) Per Common Share

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

	2008	2007	2006
Net income (loss)	$ 46,203,218	$ (430,517)	$ 1,858,944
Preferred stock dividends	(4,234,050)	(4,453,872)	(3,648,925)
Net income (loss) available to common stockholders	$ 41,969,168	$ (4,884,389)	$ (1,789,981)
Weighted-average number of shares of Common Stock – basic (denominator)	5,371,377	4,330,282	3,231,000
Income (loss) per share - basic	$ 7.81	$ (1.13)	$ (0.55)
Weighted-average number of shares of Common Stock – diluted (denominator)	10,360,348	4,330,282	3,231,000
Income (loss) per share – diluted	$ 4.46	$ (1.13)	$ (0.55)

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 2007 and 2006, due to antidilution.

Potential dilutive securities (vested stock options, vested restricted stock, vested stock warrants and convertible preferred stock) in 2007 and 2006 have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. The potentially dilutive shares would have been 5,186,148 shares and 5,581,202 shares in 2007 and 2006, respectively.

15. Income Taxes

Income tax expense (benefit) for 2008, 2007 and 2006 consist of the following:

	2008	2007	2006
Current tax expense	$ 574,752	$ —	$ —
Deferred tax expense (benefit)	26,116,055	(410,361)	1,425,305
Income tax expense (benefit)	$ 26,690,807	$ (410,361)	$ 1,425,305

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, 2008, 2007 and 2006, respectively:

	2008		2007		2006	
Income (Loss) Before Income Taxes	$ 72,894,025		$(840,878)		$ 3,284,249	
Income Tax Expense (Benefit) at Statutory Rate	$ 25,512,909	35.0%	$(294,307)	35.0%	$ 1,149,487	35.0%
Effect for Permanent Items	307,425	0.4%	35,901	-4.3%	(14,339)	-0.4%
State Taxes and Other	870,473	1.2%	(151,955)	18.1%	290,157	8.8%
Income Tax Expense (Benefit)	$ 26,690,807	36.6%	$(410,361)	48.8%	$ 1,425,305	43.4%

As of December 31, 2008, we had net operating loss carryforwards of approximately $15.6 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 through 2026.

Significant components of the Company's deferred tax assets and liabilities are as follows:

	December 31, 2008	December 31, 2007
Deferred tax assets		
Net operating loss carryforwards	$ 5,599,532	$ 11,470,413
Income tax credits	397,767	117,695
Derivative instruments	—	5,973,543
Deferred compensation	5,032,928	3,175,717
Other	130,910	688,917
Deferred tax assets before valuation allowance	11,161,137	21,426,285
Valuation Allowance	(3,260,875)	(3,442,034)
Net deferred tax assets	7,900,262	17,984,251
Deferred tax liabilities		
Oil and gas properties	(19,712,706)	(16,361,040)
Derivative instruments	(12,128,079)	—
Deferred tax liabilities	(31,840,785)	(16,361,040)
Net deferred tax (liabilities) assets	$ (23,940,523)	$ 1,623,211

Our deferred taxes increased by approximately $25.6 million during 2008. Deferred tax assets are shown net of a $3.3 million valuation allowance.

We adopted the provisions of the FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109" ("*FIN 48*") on January 1, 2007, which resulted in a reduction to stockholders' equity of $354,168. On the date of adoption, we had $518,219 of unrecognized tax benefits. There were no changes to this unrecognized tax benefit in 2007 and 2008.

Our policy is to recognize interest and penalties related to uncertain tax positions as income tax expense. We recorded no potential interest expense and penalties related to unrecognized tax benefits associated with uncertain tax positions recognized in our provision for income taxes. To the extent that interest and penalties are assessed with respect to uncertain tax positions, amounts accrued will be reflected as additional income tax expense.

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, 2008. 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, 2008 and 2007 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2008				
Net sales	$ 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
2007				
Net sales	$ 4,547,126	$ 26,658,550	$ 38,008,650	$ 40,328,882
Income (loss) from operations	(557,405)	9,897,272	15,672,330	8,604,102
Net income (loss) available to common stockholders	(2,458,088)	3,393,147	4,488,012	(10,307,460)
Income(loss)per common share				
Basic	$ (0.74)	$ 0.84	$ 0.93	$ (2.02)
Diluted	$ (0.74)	$ 0.45	$ 0.63	$ (2.02)
Weighted average shares outstanding				
Basic	3,333,806	4,046,510	4,827,731	5,091,206
Diluted	3,333,806	9,369,974	9,745,276	5,091,206

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 are made using year end natural gas and crude oil sales prices 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, 2008, 2007 and 2006, 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, 2005	24,650,263	2,707,523	—	40,895,401
Revisions	882,566	(21,823)	—	751,628
Extensions, discoveries and additions	7,397,142	—	—	7,397,142
Production	(1,542,423)	(184,881)	—	(2,651,709)
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	—	—	—	—
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	(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
PROVED DEVELOPED RESERVES:				
December 31, 2006	27,145,360	2,249,424	—	40,641,904
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

(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.

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

	2008	2007	2006
Future cash inflows	$ 749,121,400	$ 1,125,374,500	$ 313,312,927
Future production and development costs			
Production	214,969,100	258,028,900	108,693,762
Development	86,068,300	65,779,100	26,229,488
Future cash flows before income taxes	448,084,000	801,566,500	178,389,677
Future income taxes	(46,695,950)	(198,920,968)	(43,534,046)
Future net cash flows after income taxes	401,388,050	602,645,532	134,855,631
10% annual discount for estimated timing of cash flows	(140,485,818)	(203,122,453)	(57,442,604)
Standardized measure of discounted future net cash flows	$ 260,902,233	$ 399,523,079	$ 77,413,027

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

	2008	2007	2006
Beginning of year	$ 399,523,079	$ 77,413,027	$ 118,397,139
Changes from:			
Purchases of proved reserves	69,628,594	324,427,750	—
Sales of producing properties	(2,817,597)	—	—
Extensions, discoveries and improved recovery, less related costs	77,931,000	43,636,200	12,096,684
Sales of natural gas, crude oil and natural gas liquids produced, net of production costs	(148,588,993)	(85,425,742)	(13,950,146)
Revision of quantity estimates[1]	(44,029,057)	(15,028,200)	1,980,452
Accretion of discount	39,952,308	10,240,157	17,156,239
Change in income taxes	101,522,054	(88,340,375)	28,176,711
Changes in estimated future development costs	(32,461,195)	(8,693,224)	(946,764)
Development costs incurred that reduced future development costs	20,342,054	20,561,154	6,465,719
Change in sales and transfer prices, net of production costs	(227,731,733)	82,348,797	(75,110,065)
Changes in production rates (timing) and other	7,631,719	38,383,535	(16,852,942)
End of year	$ 260,902,233	$ 399,523,079	$ 77,413,027

(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 26, 2009, 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(a)(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 26, 2009

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 and 2006

DECRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIONS	BALANCE AT END OF PERIOD
For the year ended December 31, 2006				
Accounts receivable	$ 30,674	87,436	—	$ 118,110
Valuation allowance for deferred tax assets	$ 3,079,715	—	—	$ 3,079,715
For the year ended December 31, 2007:				
Accounts receivable	$ 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:				
Accounts receivable	$ 215,015	—	—	$ 215,015
Valuation allowance for deferred tax assets	$ 3,442,034	—	(181,159)	$ 3,260,875