RAM ENERGY RESOURCES INC
Form 10-K
March 11, 2010

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d)**

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2009

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: 000-50682

RAM Energy Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**20-0700684**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
5100 East Skelly Drive, Suite 650	
Tulsa, Oklahoma	**74135**
(Address of principal executive office)	**(Zip Code)**

(918) 663-2800

(Registrant s telephone number, including area code)

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

Common Stock, $.0001 par value

Warrants to Purchase

Common Stock

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

None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ 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 accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ¨	Accelerated Filer ¨
Non-Accelerated Filer ¨	Smaller reporting company þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No þ

As of March 10, 2010, there were outstanding 77,966,601 shares of registrant s $.0001 par value common stock. Based upon the closing price for the registrant s common stock on the NASDAQ Capital Market as of June 30, 2009, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $30.7 million. Documents incorporated by reference: The information called for by Part III is incorporated by reference to the definitive proxy statement for the Registrant s 2010 annual meeting of stockholders, which will be filed with the Securities and Exchange Commission, or SEC, no later than 120 days after December 31, 2009.

RAM ENERGY RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2009

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PART I

Item 1. *Business*
Overview

We have included definitions of technical terms important to an understanding of our business under Glossary of Oil and Natural Gas Terms.

Unless the context otherwise requires, all references in this report to RAM Energy Resources, our, us, and we refer to RAM Energy Resources, Inc. (formerly known as Tremisis Energy Acquisition Corporation) and its subsidiaries, as a combined entity. All references in this report to RAM Energy refer to our wholly owned subsidiary RAM Energy, Inc. and its subsidiaries, and to Ascent or Ascent Energy refer to Ascent Energy Inc. and its subsidiaries as and when acquired by us in November 2007. Unless the context otherwise requires, the information contained in this report gives effect to the May 8, 2006 consummation of the merger of RAM Energy Acquisition, Inc., our wholly owned subsidiary, with and into RAM Energy, and the change of our name from Tremisis Energy Acquisition Corporation to RAM Energy Resources, Inc., which transactions are collectively called the RAM Energy acquisition, and to our November 29, 2007 acquisition of Ascent Energy, which we refer to as the Ascent acquisition. See Item 2. Properties Ascent Acquisition for a discussion of the merger. As used in this report, Modified EBITDA refers to net income (loss) before interest expense, amortization and depreciation, accretion, income taxes, share-based compensation, impairment charges, settlement charges and unrealized gains (losses) on derivatives.

We were incorporated in Delaware on February 5, 2004. Our operations are encompassed in our wholly owned primary subsidiaries, RAM Energy and RAM Operating Company, Inc., successor by merger to Ascent Energy, and their respective subsidiaries. Our executive offices are located at 5100 East Skelly Drive, Suite 650, Tulsa, Oklahoma 74135 (918) 663-2800. We also have offices in Plano and Houston, Texas.

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Louisiana and Oklahoma. Our producing properties are located in highly prolific basins with long histories of oil and natural gas operations. We have been active in our core producing areas of Texas, Oklahoma and Louisiana since our inception in 1987 and have grown through a balanced strategy of acquisitions, development and exploratory drilling. We have completed over 24 acquisitions of producing oil and natural gas properties and related assets for an aggregate purchase price in excess of $735.0 million. On November 29, 2007, we acquired Ascent Energy in a cash and stock transaction valued at $303.8 million. Through December 31, 2009, we have drilled or participated in the drilling of over 750 oil and natural gas wells, approximately 94% of which were successfully completed and produced hydrocarbons in commercial quantities. Our management team has extensive technical and operating expertise in all areas of our geographic focus.

Our oil and natural gas assets are characterized by a combination of developing and mature reserves and properties. We have mature oil and mature natural gas reserves located primarily in Jack, Wise, Wichita and Wilbarger Counties, Texas, Pontotoc County, Oklahoma, and in several parishes in Louisiana. We have developing reserves and production in two main onshore locations:

- South Texas Starr, Wharton and Duval Counties, Texas; and
- North Texas Barnett Shale Our Tier 1 Barnett Shale acreage is located in Jack and Wise Counties, Texas, where we own interests in approximately 27,018 gross (6,594 net) acres. Our Tier 2 Barnett Shale acreage is located in Bosque and Hamilton Counties, Texas, where we own interests in approximately 1,079 gross (833 net) acres.

As of December 31, 2009, our estimated net proved reserves were 33.9 MMBoe, of which approximately 41% were crude oil, 44% were natural gas, and 15% were natural gas liquids, or NGLs. The PV-10 Value of our proved reserves was approximately $336.1 million based on benchmark prices of $61.18 per Bbl of oil and $3.87 per Mcf of natural gas. The benchmark prices reflect the unweighted arithmetic average of the first-day-of-the-month price for oil and natural gas during each month of 2009, as required by SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting,* effective December 31, 2009. For more information regarding our PV-10 Value, including a reconciliation to the standardized measure of discounted future net cash flows relating to our estimated proved reserves, see Item 2. *Properties Oil and Natural Gas Reserves.* At December 31, 2009, our proved developed reserves comprised 57% of our total proved reserves.

At December 31, 2009, we owned interests in approximately 4,000 wells and were the operator of leases upon which approximately 3,000 of these wells are located. The PV-10 Value attributable to our interests in the properties we operate represented approximately 91% of our aggregate PV-10 Value as of December 31, 2009. We also own a drilling rig, various gathering systems, a natural gas processing plant, service rigs and a supply company that service our properties.

During the twelve months ended December 31, 2009, we drilled or participated in the drilling of 49 wells on our oil and natural gas properties, 45 of which were successfully completed as producing wells, one of which was a dry hole well and three of which were either drilling or waiting to be completed at the end of that period. For the twelve months ended December 31, 2009, we generated Modified EBITDA of $58.3 million from production averaging nearly 7,000 Boe per day. For more information regarding our Modified EBITDA, including a reconciliation to our net income (loss), see Item 6. *Selected Financial Data.*

Our Business Strategy and Strengths

Our primary objective is to enhance stockholder value by increasing our net asset value, net reserves and cash flow per share through acquisitions, development, exploitation, exploration and divestiture of oil and natural gas properties. We intend to follow a balanced risk strategy by allocating capital expenditures in a combination of lower risk development and exploitation activities and higher potential exploration prospects. We intend to pursue acquisitions during periods of attractive acquisition values and emphasize development of our reserves during periods of higher acquisition values. Key elements of our business strategy include the following:

- *Maintain a policy of capital programs funded through operating cash flow*. In this current period of financial industry uncertainty leading to more restrictive capital markets, we believe that maintaining ample liquidity for capital drilling programs to be a critical component of our strategy. Our 2010 capital budget of $50.0 million is expected to be fully funded through operating cash flows.

- *Concentrate on Our Existing Core Areas*. We intend to focus a significant portion of our growth efforts in our existing core areas in Texas, Oklahoma and Louisiana. Our oil and natural gas properties in our core areas are characterized by long reserve lives and production histories in multiple oil and natural gas horizons. We believe our focus on and experience in our core areas may expose us to acquisition opportunities which may not be available to the entire industry.

- *Develop and Exploit Existing Oil and Natural Gas Properties*. Since inception our principal growth strategy has been to develop and exploit our acquired and discovered properties until we determine that it is no longer economically attractive to do so. As of December 31, 2009, we have identified over 300 development and extension drilling projects and more than 140 recompletion/workover projects on our existing properties and wells.

- *Continue to Evaluate Our North Texas Barnett Shale Development.* Due to the high degree of commercial success in the north Texas Barnett Shale by the oil and natural gas industry, we expect to continue drilling in our Tier 1 north Texas Barnett Shale properties as commodity prices warrant. We have drilled 20 gross (7 net) wells to date with a 100% success rate**.** One gross (0.04 net) additional well was in the process of completing at year end.

- *Complete Selective Acquisitions and Divestitures*. We seek to acquire producing oil and natural gas properties, primarily in our core areas. Our experienced senior management team has developed our

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acquisition criteria designed to increase reserves, production and cash flow per share on an accretive basis. We will seek acquisitions of producing properties that will provide us with opportunities for reserve additions and increased cash flow through operating improvements, production enhancement and additional development and exploratory prospect generation opportunities. In addition, from time to time, we may engage in strategic divestitures when we believe our capital may be redeployed to higher return projects.

Maintain Emphasis on Exploration Activity to Build an Inventory of Opportunities. We are committed to maintaining our emphasis on exploration activities within the context of our balanced risk objectives. We will continue to acquire, review and analyze 3-D seismic data to generate exploratory prospects. Our exploration efforts utilize available geological and geophysical technologies to reduce our exploration and drilling risks and, therefore, maximize our probability of success. We believe these opportunities will provide a basis for structured growth as commodity prices improve in the future.

We believe that the following strengths complement our business strategy:

Management Experience and Technical Expertise. Our key management and technical staff possess an average of 30 years of experience in the oil and natural gas industry, a substantial portion of which has been focused on operations in our core areas. We believe that the knowledge, experience and expertise of our staff will continue to support our efforts to enhance stockholder value.

Balanced Oil and Natural Gas Production. At year-end 2009, approximately 41% of our estimated proved reserves were oil, 44% were natural gas and 15% were NGLs. We believe this balanced commodity mix, combined with our prudent use of derivative contracts, will provide sufficient diversification of sources of cash flow and will lessen the risk of significant and sudden decreases in revenue from localized or short-term commodity price movements.

Operating Efficiency and Control. We currently operate wells that represent approximately 91% of our aggregate PV-10 Value at December 31, 2009. Our high degree of operating control allows us to control capital allocation and expenses and the timing of additional development and exploitation of our producing properties.

Drilling Expertise and Success. Our management and technical staff have a long history of successfully drilling oil and natural gas wells. Through December 31, 2009, we drilled or have participated in the drilling of over 750 oil and natural gas wells with over 94% success rate. We expect to continue to grow by utilizing our drilling expertise and developing and finding additional reserves, although our success rate may decline as we drill more exploratory wells.

Ownership and Control of Service and Supply Assets. In our Electra/Burkburnett mature oil field, we own and control service and supply assets, including a drilling rig, service rigs, a supply company, gathering systems and other related assets. We believe that ownership and use of these assets for our own account provides us with a significant competitive advantage with respect to availability, lead-time and cost of these services.

Insider Ownership. At March 11, 2010 our directors, executive officers and our two principal stockholders beneficially owned approximately 52% of our outstanding shares of common stock, providing a strong alignment of interest between management, the board of directors and our outside stockholders.

Glossary of Oil and Natural Gas Terms

The definitions set forth below apply to the indicated terms as used in this report. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

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

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Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

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

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

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

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

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

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand Boe.

MMBoe. One million Boe.

Mcf. One thousand cubic feet of natural gas.

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

MMBtu. One million Btus.

MMcf. One million cubic feet of natural gas.

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

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease.

PV-10 Value. When used with respect to oil and natural gas reserves, the estimated future gross revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using the prices provided in this report and costs in effect as of the date indicated, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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

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Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.

Proved developed reserves. Proved reserves that are expected to be recovered from existing wellbores, whether or not currently producing, without drilling additional wells. Production of such reserves may require a recompletion.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved 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.

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

Reserve life. A ratio determined by dividing our estimated existing reserves determined as of the stated measurement date by production from such reserves for the prior twelve month period.

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

3-D seismic. The method by which a three dimensional image of the earth s subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

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FORWARD LOOKING STATEMENTS

This report, including information included in, or incorporated by reference from future filings by us with the SEC, as well as information contained in written material, press releases and oral statements issued by us or on our behalf, contain, or may contain, certain statements that are forward-looking statements within the meaning of federal securities laws that are subject to a number of risks and uncertainties, many of which are beyond our control. This report modifies and supersedes documents filed by us before this report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contain in this report. All statements, other than statements of historical fact, included or incorporated by reference in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to identify forwa statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- financial strategy;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of oil and natural gas;
- property acquisitions;
- costs of developing our properties and conducting other operations;

general economic conditions;

uncertainty regarding our future operating results; and

plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this report, and, except as required by law, we do not intend to update any of these forward-looking statements to reflect changes in events or circumstances that arise after the date of this report. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under *Risk Factors* and *Management s Discussion and Analysis of Financial Condition and Results of Operations* and elsewhere in this report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf. The market data and certain other statistical information used throughout this report are based on independent industry publications, government publications or other published independent sources. Some data are also based on our good faith estimates. Although we believe these third-party sources are reliable, we have not independently verified the information and cannot guarantee its accuracy and completeness.

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

We face a variety of risks that are inherent in our business and our industry, including operational, legal and regulatory risks. The following are the known, material risks that could affect our business and our results of operations.

Risks Related to Our Business

The volatility of oil and natural gas prices greatly affects our profitability.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in further write-downs of the carrying values of our oil and natural gas properties as a result of our use of the full cost accounting method.

Wide fluctuations in oil and natural gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- speculation in the price of commodities in the commodity futures market;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of drilling rigs and completion equipment;
- the availability of pipeline capacity;
- the price and volume of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and

the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty.

Oil and natural gas prices could decline to a point where it would be uneconomic for us to sell our oil and natural gas at those prices, which could result in a decision to shut in production until the prices increase.

Our oil and natural gas properties will become uneconomic when oil and natural prices decline to the point at which our revenues are insufficient to recover our lifting costs. For example, in 2009, our average lifting costs were approximately $16.82 per Boe, or $2.80 per Mcf. A market price decline below that price would result in our having to shut in certain production until prices increase.

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A continued decline of oil and natural gas prices or a prolonged period of reduced oil and natural gas prices could result in a decrease in our exploration and development expenditures, which could negatively impact our future production.

We currently expect to have sufficient cash flows from operations to meet our projected non-acquisition capital expenditure needs for 2010. However, if oil and natural gas prices decline or reduce to lower levels for a prolonged period of time, we may be unable to continue to fund capital expenditures at historical levels due to the decreased cash flows that will result from such reduced oil and natural gas prices. Additionally, a continuing decline in oil and natural gas prices or a prolonged period of lower oil and natural gas prices could result in a reduction of our borrowing base under our current credit facility, which will further reduce the availability of cash to fund our operations. As a result, we may have to reduce our capital expenditures in future years. A decrease in our capital expenditures will likely result in a decrease in our production levels.

Continued weakness in economic conditions or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

U.S. and global economies and financial systems have recently experienced turmoil and upheaval characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of financial institutions, increased levels of unemployment, and an unprecedented level of intervention by the U.S. federal government and other governments. Although some portions of the economy appear to have stabilized and there have been signs of the beginning of recovery, the extent and timing of a recovery, and whether it can be sustained, are uncertain. Continued weakness in the U.S. or global economies could materially adversely affect our business and financial condition. For example:

- the demand for oil and natural gas in the U.S. has declined and may remain at low levels or further decline if economic conditions remain weak, and continue to negatively impact our revenues, margins, profitability, operating cash flows, liquidity and financial condition;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business, including for exploration and/or development of our reserves; and
- our commodity hedging arrangements could become ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection.

Oil and natural gas prices have declined significantly in 2009 as compared to 2008 and may continue to decline. Our profitability is directly related to the prices we receive for the sale of the oil and natural gas we produce. In early July 2008, commodity prices reached record levels in excess of $140.00 per barrel for crude oil and $13.00 per Mcf for natural gas. The 2008 year ended with market prices dropping to $44.00 for crude oil and $4.00 for natural gas, a 69% to 73% decline from the earlier highs. As of December 31, 2009, market prices were in the range of $72.00 for crude oil and $4.00 for natural gas.

Our success depends on acquiring or finding additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are produced, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we must commence exploratory drilling, undertake other replacement activities or utilize third parties to accomplish these activities. There can be no assurance, however, that we will have sufficient resources to undertake these actions, that our exploratory

projects or other replacement activities will result in significant additional reserves or that we will succeed in

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drilling productive wells at low finding and development costs. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

In accordance with customary industry practice, we rely in part on independent third party service providers to provide most of the services necessary to drill new wells, including drilling rigs and related equipment and services, horizontal drilling equipment and services, trucking services, tubular goods, fracing and completion services and production equipment. The oil and natural gas industry has experienced significant volatility in cost for these services in recent years and this trend is expected to continue into the future. Any future cost increases could significantly increase our development costs and decrease the return possible from drilling and development activities, and possibly render the development of certain proved undeveloped reserves uneconomical.

The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated.

This report and other SEC filings by us contain estimates of our proved oil and natural gas reserves and the estimated future net revenues from those reserves. These estimates are based on various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, timing of operations, and availability of funds. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates are dependent on many variables, and therefore changes often occur as these variables evolve. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, production taxes, development expenditures, operating expenses, and quantities of producible oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities of and present values related to proved reserves disclosed by us, and the actual quantities and present values may be less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development activity, prevailing oil and natural gas prices, costs to develop and operate properties, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties.

As of December 31, 2009, approximately 43%, or 14.6 MMBoe, of our estimated proved reserves were proved undeveloped, and approximately 5%, or 1.7 MMBoe, were proved developed non-producing. In order to develop our proved undeveloped reserves, we estimate approximately $135.0 million of capital expenditures would be required. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future and after some investment of capital. In order to bring production on-line for our proved developed non-producing reserves, we estimate capital expenditures of approximately $6.4 million will be required. The estimated abandonment costs associated with our Louisiana production facilities make up the balance of our anticipated capital expenditures. Although we have estimated our reserves and the costs associated with these reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

You should not assume that the PV-10 value and standardized measure of discounted future net cash flows included in this report represent the current market value of our estimated proved oil and natural gas reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. For example, our proved reserves and PV-10 Values as of December 31, 2009, were estimated using the 12-month unweighted arithmetic average of the first-day-of-the-month price of $61.18 per Bbl of oil (NYMEX West Texas Intermediate settle price) and $3.87 per Mcf of natural gas (Platts Henry Hub spot price). We then

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adjust these base prices to reflect appropriate basis, quality, and location differentials over that period in estimating our proved reserves. During 2009, our monthly average realized oil prices, excluding the effect of hedging, were as high as $75.28 per Bbl and as low as $33.18 per Bbl. For the same period, our monthly average realized natural gas prices before hedging were as high as $5.23 per Mcf and as low as $2.66 per Mcf. Many other factors will affect actual future net cash flows, including:

- Amount and timing of actual production;
- Supply and demand for oil and natural gas;
- Curtailments or increases in consumption by oil purchasers and natural gas pipelines; and
- Changes in government regulations or taxes.

The timing of production from oil and natural gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing PV-10 Values. In addition, the ten percent discount factor required by the SEC to be used to calculate PV-10 Values for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and natural gas industry in general are subject.

Reserve estimates as of December 31, 2009, have been prepared under the SEC s new rules for oil and gas reporting that are effective for fiscal years ending on or after December 31, 2009. These new rules require SEC reporting companies to prepare their reserve estimates using, among other things, revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing, instead of the prior requirement to use pricing at the end of the period. The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules in the near future. The interpretation of these rules and their applicability in different situations remains unclear in many respects. Changing interpretations of the rules or disagreements with our interpretations could result in revisions to our reserve estimates or write-downs in our reserves.

We expect to obtain a substantial portion of our funds for property acquisitions and for the drilling and development of our oil and natural gas properties through a combination of cash flows from operations and borrowings. If such borrowed funds were not available to us, or if the terms upon which such funds would be available to us were unfavorable, our ability to acquire oil and natural gas properties, the further development of our oil and natural gas reserves, and our financial condition and results of operations, could be adversely affected.

We expect to fund a substantial portion of our future property acquisitions and our drilling and development operations with a combination of cash flows from operations and borrowed funds. To the extent such borrowed funds are not available to us at all, or if the terms under which such funds would be available to us would be unfavorable, our ability to acquire oil and natural gas properties and the further development of our oil and natural gas reserves could be adversely impacted. In such events, we may be unable to replace our reserves of oil and natural gas which, subsequently, could adversely affect our financial condition and results of operations.

The continued tightness in the financial and credit markets may expose us to counterparty risk with respect to our sales of oil and natural gas.

We sell our crude oil, natural gas and natural gas liquids to a variety of purchasers. Some of these parties are not as creditworthy as we are and may experience liquidity problems**.** Nonperformance by a trade creditor could result in our incurring losses.

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The soundness of financial institutions could place our cash deposits at risk.

Current market conditions also elevate the concern over our cash accounts, which total approximately $0.1 million, as of December 31, 2009. Our cash investments and deposits with any financial institution that exceed the amount insured by the Federal Deposit Insurance Corporation are at risk in the event one of these financial institutions should fail.

Operating hazards and uninsured risks may result in substantial losses.

Our operations are subject to all of the hazards and operating risks inherent in drilling for, and the production of, oil and natural gas, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. There can be no assurance that any insurance will be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance, or its availability at premium levels that justify its purchase. In addition, we may be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities would not be covered by our insurance.

Our operations are subject to various governmental regulations that require compliance that can be burdensome and expensive.

Our operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge from drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and natural gas. In addition, the production, handling, storage, transportation and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. These laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management, and compliance with these laws may cause delays in the additional drilling and development of our properties. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. While historically we have not experienced any material adverse effect from regulatory delays, there can be no assurance that such delays will not occur in the future.

Unusual weather patterns or natural disasters, whether due to climate change or otherwise, could negatively impact our financial condition.

Our business depends, in part, on normal weather patterns across the United States Natural gas demand and prices are particularly susceptible to seasonal weather trends. Warmer than usual winters can result in reduced demand and high season-end storage volumes, which can depress prices to unacceptably low levels. In addition, because a majority of our properties are located in Texas, Louisiana and Oklahoma, our operations are constantly at risk of extreme adverse weather conditions such as hurricanes and tornadoes. Any unusual or prolonged adverse weather patterns in our areas of operations or markets, whether due to climate change or otherwise, could have a material and adverse impact on our business, financial condition and cash flow. In addition, our business, financial condition and cash flow could be adversely affected if the businesses of our key vendors, purchasers, contractors, suppliers or transportation service providers were disrupted due to severe weather, such as hurricanes or floods, whether due to climate change or otherwise.

Climate change and government laws and regulations related to climate change could negatively impact our financial condition.

In addition to other climate-related risks set forth in this Risk Factors section, we are and will be, directly and indirectly, subject to the effects of climate change and may, directly or indirectly, be affected by government laws and regulations related to climate change. We cannot predict with any degree of certainty what effect, if any, possible climate change and government laws and regulations related to climate change will have on our operations, whether directly or indirectly. While we believe that it is difficult to assess the timing and effect of climate change and pending legislation and regulation related to climate change on our business, we believe that climate change and government laws and regulations related to climate change may affect, directly or indirectly, (i) the cost of the equipment and services we purchase, (ii) our ability to continue to operate as we have in the past, including drilling, completion and operating methods, (iii) the timeliness of delivery of the materials and services we need and the cost of transportation paid by us and our vendors and other providers of services, (iv) insurance premiums, deductibles and the availability of coverage, and (v) the cost of utility services, particularly electricity, in connection with the operation of our properties. In addition, climate change may increase the likelihood of property damage and the disruption of our operations, especially in coastal states. As a result, our financial condition could be negatively impacted by significant climate change and related governmental regulation, and that impact could be material.

Regulation and recent court decisions related to greenhouse gas emissions could have an adverse effect on our operations and demand for oil and natural gas.

The U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases, including carbon dioxide, methane and nitrous oxide among others, which some recent studies have suggested may be contributing to warming of the earth s atmosphere. In addition, several states have already taken legal measures to reduce emissions of greenhouse gases.

As a result of the U.S. Supreme Court s decision on April 2, 2007 in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the Clean Air Act (CAA) definition of air pollutant, the Environmental Protection Agency (EPA) was required to determine whether emissions of greenhouse gases endanger public health or welfare. In April 2009, EPA proposed a finding of such endangerment. Consistent with its proposed endangerment finding, in September 2009, EPA proposed regulations to control greenhouse gas emissions from light duty vehicles. The EPA also announced that its proposed action to control greenhouse gas emissions from light duty vehicles, should it become final, would automatically trigger application of the CAA prevention of significant deterioration and Title V operating permit programs to major stationary sources of greenhouse gas emissions. In September 2009, the EPA issued a proposed tailoring rule explaining the legal mechanism upon which it would rely to raise the major stationary source air pollutant emission threshold of 250 tons per year and 100 tons per year to 25,000 tons per year. With its proposed tailoring rule, the EPA also explained the manner in which it would implement the CAA permitting programs to major stationary source greenhouse gas emission sources. In September 2009, the EPA promulgated a final mandatory greenhouse gas reporting rule which will assist EPA in implementing the major stationary source permitting programs triggered by the mobile source rules. This reporting rule became effective on December 29, 2009. On December 15, 2009, the EPA promulgated its final endangerment rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act. This final rule became effective on January 14, 2010. Currently, the EPA is expected to promulgate its final rules regulating and controlling greenhouse gas emissions from light duty vehicles, as well as its final tailoring rule, in March 2010. Though subject to legal challenge, the EPA s rules promulgated thus far are currently final and effective, and will remain so unless successfully challenged directly in court, or unless Congress adopts legislation preempting EPA s regulatory authority to address greenhouse gases under the CAA.

Beyond legislative and regulatory developments, there have been several court cases impacting this area of risk. These cases expose other significant emission sources of greenhouse gases to litigation risk. The effect of this recent case law may be mitigated by actions that the courts determine displace federal common law,

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potentially including Congressional adoption of greenhouse gas legislation or the EPA s final adoption of the light duty vehicle emission regulations which, without legislative intervention, will trigger application of other CAA provisions to greenhouse gas emissions.

Other nations have already agreed to regulate emissions of greenhouse gases, pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Though the 15th meeting of the Council of the Parties in Copenhagen in December 2009 failed to result in a final agreement, international negotiations continue, with the participation of the United States.

International developments, passage of state or federal climate control legislation or other regulatory initiatives, the adoption of regulations by EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which we conduct business, or further development of case law allowing claims based upon greenhouse gas emissions, could have an adverse effect on our operations and the demand for oil and natural gas and increase the costs of our operations.

Potential legislative and regulatory actions relating to Federal income taxation and derivatives trading could increase our costs, reduce our revenue and cash flow from oil and natural gas sales, reduce our liquidity or otherwise alter the way we conduct our business.

Pending federal budget proposals released by the White House on February 26, 2009 and February 1, 2010 would potentially increase and accelerate the payment of federal income taxes of independent producers of oil and natural gas. Proposals that would significantly affect us include, but are not limited to, repealing the expensing of intangible drilling costs, repealing the percentage depletion allowance, repealing the manufacturing tax deduction for oil and natural gas companies and increasing the amortization period of geological and geophysical expenses. Additionally, the Senate Bill version of the Oil Industry Tax Break Repeal Act of 2009, introduced on April 23, 2009, and the Senate Bill version of the Energy Fairness for America Act, introduced on May 20, 2009, include many of the proposals outlined in the federal budget proposals. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation as a result of the budget proposals, either Senate Bill or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change (i) would make it more costly for us to explore for and develop our oil and natural gas reserves and (ii) could negatively affect our financial condition and results of operations.

The U.S. Congress is considering measures aimed at increasing the transparency and stability of the over-the-counter (OTC) derivative markets and preventing excessive speculation. We maintain an active price and basis protection hedging program related to the oil and natural gas we produce. Additionally, we have used the OTC market exclusively for our oil and natural gas derivative contracts and rely on our hedging activities to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. Proposals being considered would impose clearing and standardization requirements for all OTC derivatives and restrict trading positions in the energy futures markets. Such changes would likely materially reduce our hedging opportunities and could negatively affect our revenues and cash flow during periods of low commodity prices.

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

We utilize hydraulic fracturing as a means to enhance the productive capability of our wells, particularly in shale formations such as the producing zone in our North Texas Barnett Shale wells. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could repeal the exemptions for hydraulic fracturing from the Safe Drinking Water Act which would allow the EPA to establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing, which could result in limiting the productive capability of future wells in which we likely would utilize hydraulic fracturing and increase our costs of compliance and doing business.

We may not be able to borrow the full amount of the borrowing base under our revolving credit facility because of the amount of our Modified EBITDA. The inability to fully borrow funds up to our borrowing base could reduce our capital expenditures.

As of December 31, 2009, our borrowing base under our revolving credit facility was $175.0 million. As of the same date, we had outstanding advances under the revolving credit facility of $135.0 million, leaving an aggregate availability under our revolver of $40.0 million. However, because of the amount of our Modified EBITDA, the financial covenants set forth in our credit facility would have limited us to additional borrowings under our revolving credit facility as of December 31, 2009 of $25.3 million. We will be unable to borrow the full amount of our borrowing base until our Modified EBITDA for the preceding four fiscal quarters equals or exceeds $63.6 million. Our inability to borrow the full amount of our borrowing base under our revolving credit facility could reduce our current year capital expenditures if we do not meet our goal of funding our 2010 capital expenditures from our operating cash flow.

Our method of accounting for investments in oil and natural gas properties may result in a further impairment of asset value, which could affect our stockholder equity and net profit or loss.

We use the full cost method of accounting for our investment in oil and natural gas properties. Under the full cost method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves are capitalized into a full cost pool. Capitalized costs in the pool are amortized and charged to operations using the units-of-production method based on the ratio of current production to total proved oil and natural gas reserves. To the extent that such capitalized costs, net of amortization, exceed the after tax present value of estimated future net revenues from our proved oil and natural gas reserves (using a 10% discount rate) at any reporting date, such excess costs are charged to operations. In 2009, we recorded a $47.6 million charge for the impairment of our oil and natural gas properties. This amount is in addition to the $269.4 million charge we recorded in 2008. These writedowns are not reversible at a later date, even if the present value of our proved oil and natural gas reserves increases as a result of an increase in oil or natural gas prices. Further price declines could result in additional impairments of asset value.

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

As part of our business strategy, we continually seek acquisitions of oil and natural gas properties. The successful acquisition of oil and natural gas properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including the following:

- future oil and natural gas prices;
- the amount of recoverable reserves;
- future operating costs;

- future development costs;
- failure of titles to properties;
- costs and timing of plugging and abandoning wells; and
- potential environmental and other liabilities.

Our assessment will not necessarily reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. With respect to properties on which there is current production, we may not inspect every well location, potential well location or pipeline in the course of our due diligence. Inspections may not reveal structural and environmental problems such as pipeline corrosion or groundwater contamination. We may not be able to obtain or recover on contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We face extensive competition in our industry.

We operate in a highly competitive environment. We compete with major and independent oil and natural gas companies, many of whom have financial and other resources substantially in excess of those available to us. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

Our use of derivative contracts is subject to risks that our counterparties may default on their contractual obligations to us and may cause us to forego additional future profits or result in our making cash payments.

Our use of derivative contracts could have the effect of reducing our revenues and the value of our common stock. To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into derivative contracts for a portion of our oil and natural gas production. Our derivative contracts are subject to mark-to-market accounting treatment. The change in the fair market value of these instruments is reported as a non-cash item in our statement of operations each quarter, which typically result in significant variability in our net income. Derivative contracts expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

- the counterparty to the derivative contract may default on its contractual obligations to us;
- there is a widening of the price differentials between delivery points for our production and the delivery point assumed in the derivative contract; or
- our production is less than our hedged volumes.

The ultimate settlement amount of these unrealized derivative contracts is dependent on future commodity prices. We may incur significant unrealized losses in the future from our use of derivative contracts to the extent market prices increase and our derivatives contracts remain in place. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk* appearing elsewhere in this report.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures will depend on our ability to generate cash from operations and other resources in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, including the prices that we receive for oil and natural gas.

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Our business may not generate sufficient cash flow from operations and future borrowings may not be available to us in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. None of these remedies may, if necessary, be effected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, which could cause us to default on our obligations and could impair our liquidity.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our credit agreement contains a number of significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur or guarantee additional indebtedness and issue certain types of preferred stock;
- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale or leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our credit agreement. Also, our credit agreement requires 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, as a result, we may be unable to 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 corporate activities. A decline in oil and natural gas prices, or a prolonged period of oil and natural gas prices at lower levels, could eventually result in our failing to meet one or more of the financial covenants under our credit facility, which could require us to refinance or amend the facility resulting in the payment of consent fees or higher interest rates, or require us to raise additional capital at an inopportune time or on terms not favorable to us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit agreement. A default under our credit agreement, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit agreement. The accelerated debt would become immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

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Risks Related to Our Common Stock

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

We intend to retain any future earnings to fund our operations; therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future.

Substantial stock ownership by our executive officers, directors and other affiliates may limit the ability of our non-affiliate stockholders to influence the outcome of director elections and other matters requiring stockholder approval.

Persons who are our officers and directors beneficially own approximately 18% of our outstanding common stock. Accordingly, our insiders will have significant influence in the election of our directors and, therefore, our policies and direction. This concentration of voting power could have the effect of delaying or preventing a change in our control or discouraging a potential acquirer from attempting to obtain control of us, which in turn could have a material adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the market price for their shares of common stock.

You may experience dilution of your ownership interests due to the future issuance of additional shares of our common stock, which could have an adverse effect on our stock price.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders. We are currently authorized to issue 100,000,000 shares of common stock and 1,000,000 shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As of December 31, 2009, we had outstanding 76,951,883 shares of common stock. In addition, we have reserved an additional 2,409,426 shares for future issuance to our directors, officers and employees as restricted stock or stock option awards pursuant to our 2006 Long-Term Incentive Plan. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with future acquisitions, future issuances of our securities for capital raising purposes or for other business purposes. Future sales of substantial amounts of our common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

Certain provisions of Delaware law, our certificate of incorporation and bylaws could hinder, delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

Certain provisions of Delaware law, our certificate of incorporation and bylaws could have the effect of discouraging, delaying or preventing transactions that involve an actual or threatened change in control of our company. Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. In addition, our certificate of incorporation and bylaws include the following provisions:

Classified Board of Directors. Our board of directors is divided into three classes with staggered terms of office of three years each. The classification and staggered terms of office of our directors make it more difficult for a third party to gain control of our board of directors. At least two annual meetings of stockholders, instead of one, generally would be required to effect a change in a majority of the board of directors.

Removal of Directors. Under Delaware law, directors that serve on a classified board, such as our directors, may be removed only for cause by the affirmative vote of the holders of at least a majority of the voting power of the outstanding shares of our capital stock entitled to vote.

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Number of Directors, Board Vacancies, Term of Office. Our certificate of incorporation and our bylaws provide that only the board of directors may set the number of directors. We have elected to be subject to certain provisions of Delaware law which vest in the board of directors the exclusive right, by the affirmative vote of a majority of the remaining directors, to fill vacancies on the board even if the remaining directors do not constitute a quorum. When effective, these provisions of Delaware law, which are applicable even if other provisions of Delaware law or the charter or bylaws provide to the contrary, also provide that any director elected to fill a vacancy shall hold office for the remainder of the full term of the class of directors in which the vacancy occurred, rather than the next annual meeting of stockholders as would otherwise be the case, and until his or her successor is elected and qualifies.

Advance Notice Provisions for Stockholder Nominations and Proposals. Our bylaws require advance written notice for stockholders to nominate persons for election as directors at, or to bring other business before, any meeting of stockholders. This bylaw provision limits the ability of stockholders to make nominations of persons for election as directors or to introduce other proposals unless we are notified in a timely manner prior to the meeting.

Amending the Bylaws. Our certificate of incorporation permits our board of directors to adopt, alter or repeal any provision of the bylaws or to make new bylaws. Our bylaws also may be amended by the affirmative vote of our stockholders.

Authorized but Unissued Shares. Under our certificate of incorporation, our board of directors has authority to cause the issuance of preferred stock from time to time in one or more series and to establish the terms, preferences and rights of any such series of preferred stock, all without approval of our stockholders. Nothing in our certificate of incorporation precludes future issuances without stockholder approval of the authorized but unissued shares of our common stock.

We could issue shares of preferred stock which could be entitled to dividend, liquidation and other special rights and preferences not shared by holders of our common stock or which could have anti-takeover effects.

We are authorized to issue up to 1,000,000 shares of preferred stock, which shares may be issued from time to time in one or more series as our board of directors, by resolution or resolutions, may from time to time determine. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions thereof, if any, of each such series of our preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of our certificate of incorporation and Delaware law, our board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series of our preferred stock. The issuance of any such preferred stock could materially adversely affect the rights of holders of our common stock and, therefore, could reduce the value of our common stock.

In addition, specific rights granted to future holders of preferred stock could be used to restrict our ability to merge with, or sell our assets to, a third party. The ability of our board of directors to issue preferred stock could discourage, delay or prevent a takeover of us, thereby preserving our control by the current stockholders.

Item 1B. ***Unresolved Staff Comments***

None.

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Item 2. ***Properties***

The table below summarizes our properties into three groups. The developing fields consist of core properties that have a greater probability of adding new extensions and discoveries. The mature oil and gas fields are those properties that have a history of stable production rates and in which well performance is a function of field maintenance efficiency. During 2009, we drilled 45 gross wells (44 net) that were capable of production and experienced a success rate of 98%.

The following table summarizes our estimated proved oil and gas reserves by area as of December 31, 2009 and our average daily production by area for calendar year 2009:

	Average Daily Production Boe	Oil MBbls	Gas MMcf	NGL MBbls	Equivalent MBoe	Percent of proved reserves
Developing Fields	2,222	592	55,557	3,169	13,020	39%
Mature Oil Fields	3,107	13,126	4,113	518	14,329	42%
Mature Gas Fields	1,636	349	29,557	1,296	6,573	19%
	6,965	14,067	89,227	4,983	33,922	100%

Developing Fields

The average daily production from our developing fields was 2,222 Boe per day (32% of our total daily production) in 2009, and an increase of more than 2% over the previous year. We drilled a total of four gross (3.0 net) wells in our developing fields, all of which were completed as wells capable of production. An additional five gross (1.2 net) wells were drilled to their objective depth and awaiting completion or pipeline connection at year end. As of December 31, 2009, the proved reserves in our developing fields were 13 MMBoe and account for 39% of our total proved reserves. Our most significant developing fields are as follows:

South Texas. During 2009, our net daily production from our South Texas properties averaged 1,463 Boe per day and make up 30% (10.0 MMBoe) of our total proved reserves. We drilled three gross (2.8 net) wells in our La Copita field in Starr County, Texas. All completions were successful with initial production rates up to 650 Boe per day from the Vicksburg formation. We are the operator of all of the wells in our La Copita field and our 2009 drilling program added another three new proved undeveloped locations. We have allocated $22.0 million of our 2010 budget to South Texas.

Barnett Shale Jack and Wise Counties Texas. We drilled two gross (0.4 net) wells on our Tier 1 Barnett Shale acreage in 2009, with one gross (0.4 net) well completed as a producing well and one gross (0.04 net) well in the process of being completed at the time of this report. Our net average daily production from our Barnett Shale wells was 718 Boe per day during 2009 (approximately 10% of our total average daily production for the year). We have a large acreage position within a Participation Agreement with Devon Energy Corporation in which we have the right to participate with a 36% working interest in all wells proposed in the contract area. A total of 21 gross (7.4 net) wells have been drilled since the inception of the agreement. As of December 31, 2009 we estimated our proved reserves in our Tier 1 Barnett Shale area to be 2.1 MMBoe, or 6% of our total proved reserves. Approximately $3.0 million has been budgeted for drilling in 2010 in our Barnett Shale play.

Mature Oil Fields

We produced an average of 3,107 Boe per day from our mature oil fields during 2009. We resumed the historical pace of drilling in our mature oil fields in August 2009 and finished the year drilling 40 gross (40 net) wells that were commercially productive and one gross (0.9 net) dry hole. Proved reserves in our mature oil fields as of December 31, 2009 were 14.3 MMBoe (42 % of our total proved reserves). Our mature oil fields are shallow oil fields that have historically exhibited very dependable production performance, have long life reserves and multiple drilling locations.

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Northeast Fitts and Allen Field. During 2009, we initiated the drilling of two gross (1.8 net) development wells in our Northeast Fitts unit in Pontotoc County, Oklahoma. No wells were drilled during 2009 in our Allen field of Pontotoc County and Seminole County, Oklahoma. The Northeast Fitts field produces from shallow McAlester and Hunton formations at depths less than 4,000 feet. We are the operator of the units and, as such, control the pace of operations. The Northeast Fitts field is primarily a mature waterflood. We have five wells scheduled for 2010 to test a tighter flood pattern with the intent of increasing production and improving ultimate recovery. Our Allen Field has future behind-pipe and undeveloped opportunities in shallow multi-pay reservoirs. The combined proved reserves from these two areas are 6.3 MMBoe (19% of our total proved reserves). We have budgeted $2.0 million for development costs in our Northeast Fitts and Allen fields in 2010.

Electra/Burkburnett Fields. We drilled a total of 39 gross (39 net) wells during 2009 in Wichita and Wilbarger Counties, Texas and have drilled more than 280 wells in these fields since November 1, 2004. We have budgeted $9.0 million in 2010 to continue development of this field. We own our own drilling rig and pulling units deployed exclusively for operations in these fields, and employ approximately 80 field personnel. At the same time we continue to ramp up our drilling program we are focusing on decreasing our cost to operate. We are also working to improve production performance through recompletions, workovers and improved water injection performance. As of December 31, 2009, the estimated proved reserves in these fields were 6.3 MMBoe (19% of our total proved reserves).

Mature Gas Fields

We participated in drilling one gross (1 net) well in our mature gas fields in 2009. The average daily production was 1,636 Boe per day during 2009, and the proved reserves are 6.6 MMBoe (19% of our total proved reserves). The proved reserves in our Boonsville field in Jack and Wise Counties, Texas are estimated at 2.3 MMBoe (7% of our total proved reserves). Reserves in our Lake Enfermer field in Lafourche Parish, Louisiana total 2.8 MMBoe (8% of our total proved reserves).

The following table summarizes our 2009 drilling activity:

	Developed			Exploratory		
	Gross wells Drilled (1)	Net Wells Drilled (1)	Completion Rate (%)	Gross wells Drilled	Net Wells Drilled	Completion Rate (%)
Developing Fields	4	3	100%			
Mature Oil Fields	41	40.9	98%			
Mature Gas Fields	1	1	100%			
	46	44.9	98%			

(1) Does not include three gross (0.16 net) wells that were in the process of being completed at December 31, 2009 and does not include two gross (1 net) wells that were drilled in 2008 and waiting on pipeline connection.

Development, Exploitation and Exploration Programs

Development and Exploitation Program. Our future production and performance depends to a large extent on the successful development of our existing reserves of oil and natural gas. We have identified multiple development projects on our existing properties (substantially all of which are located in our core areas), and these projects involve both the drilling of development wells and extension wells. We are the operator of leases covering approximately 2,600 of the wells in which we own interests, and as such we are able to control expenses, capital allocation and the timing of development activities on these properties. We also own interests in, and operate, approximately 670 injection wells. During the year ended December 31, 2009, we drilled or participated in the drilling of 45 gross (44 net) development wells capable of production in 2009. Capital expenditures in connection with these activities during this period aggregated approximately $28.2 million.

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Another determinant of future performance is the exploitation of existing wells that can be recompleted or otherwise reworked to extract additional hydrocarbons. We have identified approximately 140 operated projects involving recompletions in existing wells that we operate, all of which involve reserves included in our proved reserves at December 31, 2009.

Exploration Program. Historically, an important component of our strategy to expand our reserves and production has been an active exploration program focused on adding long-lived oil and natural gas reserves from our core areas and other resource plays. During 2010, assuming the continuation of existing commodity prices for oil and natural gas, we expect to conduct only limited exploration activities, primarily on our Osage concession in Northeast Oklahoma.

We have an experienced technical staff, including geologists, landmen, engineers and other technical personnel devoted to prospect generation and identification of potential drilling locations. We seek to reduce exploration risk by exploring at moderate depths that are deep enough to discover sizeable oil and natural gas accumulations (generally less than 13,000 feet). Our established presence in our core areas has provided our staff with substantial expertise. Many of our exploration plays are based upon seismic data comparisons to our existing producing fields. For exploration prospects we generate, we typically will own a greater interest in these projects than our drilling partners, if any, and will operate the wells. As a result, we will be able to influence the areas of exploration and the acquisition of leases, as well as the timing and drilling of each well.

During the year ended December 31, 2009, we did not participate in the drilling of any exploratory wells. For 2010, we have budgeted $6.0 million for geological and geophysical activities relating to exploitation and exploration projects and $6.0 million for leasehold acquisition for exploratory drilling.

Oil and Natural Gas Reserves

Our proved reserve estimates for crude oil and natural gas were prepared by Forrest A. Garb & Associates, an independent petroleum engineering firm, in accordance with the generally accepted petroleum engineering and evaluation principles and most recent definitions and guidelines established by the Securities and Exchange Commission (SEC). A copy of Forrest A. Garb & Associates summary reserve report is attached as an exhibit to this report. All reserve definitions comply with the definitions of Rules 4-10 (a) (1)-(32) of SEC Regulation S-X.

To determine our estimated proved reserves, and as required by the SEC, we used the 12-month unweighted arithmetic average of the first-day-of-the-month price for the months of January through December, 2009 calculated to be $3.87 per Mcf of natural gas and $61.18 per Bbl of oil. These prices were held constant for the life of the properties and adjusted for the appropriate market differentials.

As of December 31, 2009, our proved crude oil and natural gas reserves and PV-10 Value are presented below by reserve category. All of our proved reserves are located within the United States.

	Oil MBbl	Gas MMcf	NGL MBbl	MBoe	Reserve %	PV-10 M$
Proved developed producing	8,206	40,204	2,721	17,627	52%	$ 201,254
Proved developed non producing	608	5,955	67	1,668	5%	21,262
Proved undeveloped	5,253	43,068	2,195	14,627	43%	113,537
Total proved	14,067	89,227	4,983	33,922	100%	$ 336,053
Developed	8,814	46,159	2,788	19,295		$ 222,516
% Developed	63%	52%	56%	57%		66%

Our properties have a 13.3 year reserve-to-production ratio.

Internal Controls over Reserves Estimate

Our policies regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and values in compliance with SEC regulations. Responsibility for compliance in reserve bookings is delegated to our reservoir engineering group, which is led by our Senior Vice President of Operations.

Technical reviews are performed throughout the year by our engineering and geologic staff who evaluate pertinent geological and engineering data. This data in conjunction with economic data and ownership information is used in making a determination of proved reserve quantities. The reserve process is overseen by our Vice President of Business Development. Our internal reservoir engineering staff has an average experience of more than 20 years in the area of reserve estimating and reservoir evaluations. We have internal auditing guidelines and controls in place to monitor the reservoir data and reporting parameters used in preparing the year-end reserves. Technologies and economic data used include updated production data, well performance, formation logs, geological maps, reservoir pressure tests and wellbore mechanical integrity information. Final approval of the reserves is required by our Senior Vice President of Operations.

Our reserve estimates are certified by the independent petroleum engineering firm of Forrest A. Garb & Associates using their own engineering assumptions and the economic data which we provide. Forrest A. Garb & Associates is an independent petroleum engineering consulting firm that provides petroleum consulting services throughout the world. Forrest A. Garb is chairman of the board of his firm, and is a registered professional engineer with more than 50 years of practical petroleum industry experience. The Forrest A. Garb & Associates report is included as Exhibit 99.1.

In addition to third party reserve report preparation, our reserves are reviewed by senior management and the Audit Committee of our Board of Directors. Senior management, which includes the President and Chief Executive Officer, the Senior Vice President of Operations and the Senior Vice President and Chief Financial Officer, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews the final reserves estimate in conjunction with Forrest A. Garb & Associates certified reserve report letter. They may also meet with the key representative from Forrest A. Garb & Associates to discuss their process and findings.

Estimated quantities of proved reserves and future net revenues are affected by oil and natural gas prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond the control of the producer. The reserve data set forth in this report represent only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revisions based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors, which revisions may be material. The PV-10 Value of our proved oil and natural gas reserves does not necessarily represent the current or fair market value of such proved reserves, and the 10% discount factor may not reflect current interest rates, our cost of capital or any risks associated with the development and production of our proved oil and natural gas reserves. Proved reserves include proved developed and proved undeveloped reserves.

Transition Impact of Application of New Oil and Gas Rules

In addition to reporting our reserves using the first-day-of-the-month average prices for 2009, as required by SEC regulations, for comparative purposes we are presenting an alternate price case using year-end 2009 prices of $79.36 per Bbl and $5.79 per Mcf, consistent with SEC guidelines in effect for calendar year 2008 and prior years. At year-end 2009 prices were well above the first-day-of-the-month average prices of $61.18 per Bbl and $3.87 per Mcf.

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The table below reflects our December 31, 2009 proved reserves quantities and PV-10 Values using year-end 2009 pricing:

	Oil MBbl	Gas MMcf	NGL MBbl	MBoe	Reserve %	PV-10 M$
Proved developed producing	9,403	43,606	2,856	19,526	52%	$ 317,743
Proved developed non producing	632	6,216	97	1,765	5%	31,984
Proved undeveloped	5,706	49,786	2,319	16,323	43%	208,186
Total Proved	15,741	99,608	5,272	37,614	100%	$ 557,913
Developed	10,035	49,822	2,953	21,291		$ 349,726
% Developed	64%	50%	56%	57%		63%

Applying last year s methodology of using year-end prices, our proved reserves and PV-10 Value at December 31, 2009 would have reflected an increase of 8% and 73%, respectively, over December 31, 2008 levels.

Reserve Reconciliation

Our total proved reserve reconciliation starting at year-end 2008 and ending year-end 2009 is as follows:

	Oil MBbl	Gas MMcf	NGL MBbl	MBoe
Total proved				
As of December 31, 2008	14,285	96,952	4,325	34,769
Extensions, discoveries and additions	1,771	10,070	508	3,957
Purchases				
Sales	(15)	(3,808)		(650)
Price revisions	2,308	(8,416)	(27)	878
Production	(1,138)	(5,994)	(406)	(2,542)
Loss to 5-year rule	(751)			(751)
Revisions of previous estimates	(2,393)	423	583	(1,739)
As of December 31, 2009	14,067	89,227	4,983	33,922

We added 3.9 MMBoe in proved reserve extensions, discoveries and additions in 2009 primarily as a result of our success in our development drilling in our La Copita field of South Texas and in our mature oil area of Electra/Burkburnett in North Texas. The reserve additions in these two areas comprised 89% of the reserves added and primarily are attributable to drilling locations that were upgraded to proved undeveloped in 2009. We eliminated approximately 750 MBoe of proved undeveloped reserves due to the SEC s new five-year scheduling rule. The majority of these reserves are in smaller secondary recovery waterflood projects. Our reduction due to revisions of previous estimates is primarily due to changes in performance forecasts and revised estimates of our proved undeveloped locations in North Texas.

Proved Undeveloped Reserves

At December 31, 2009 our total proved undeveloped reserves were 14.6 MMBoe, comprised of 7.4 MMBbl of crude and natural gas liquids and 43.1 Bcf of natural gas. During 2009, we drilled 10 gross (9.8 net) wells developing 750 MBoe, or 5.7%, of our total proved undeveloped reserves as of December 31, 2008. The capital costs to develop these reserves was approximately $6.5 million. Our projected costs to develop our remaining proved undeveloped reserves are $30.7 million in 2010, $40.0 million in 2011, $38.8 million in 2012, $13.7 million in 2013 and $10.8 million in 2014.

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Also during 2009, we drilled wells at 35 locations that did not include proved reserves as of December 31, 2008. These wells helped provide the basis to add additional proved undeveloped reserves. We added 100 proved undeveloped locations in our Electra/Burkburnett area, and three proved undeveloped locations in our La Copita field during 2009.

Unproved Reserves

The new SEC guidelines allow for the disclosure of probable and possible reserves, which are unproved reserves. Disclosure of unproved reserves is optional and we have elected not to disclose any unproved reserves in this report.

Technologies Used to Establish Additions to Reserve Estimates

The revised rules permit the use of reliable technologies that have been field tested as evidence proven to establish with reasonable certainty quantities of proved reserves. They also permit assigning reserves to locations more than one offset away from standard development spacing if reasonable certainty can be established, and the estimates are economically producible. We evaluated the potential use of reliable technologies in connection with the preparation of our 2009 reserve estimates and have elected not to rely on the new rule as a means of assigning proved or unproved reserves. We are, however, actively using seismic interpretation to high grade our potential drilling locations. In future filings, we may use reliable technologies to assign reserves if the application can prove with a high degree of confidence that the estimated quantities can be recovered.

Our proved developed reserves, total proved reserves, estimated PV-10 Value and prices used after the effects of market differentials by year is as follows:

	As of December 31,		
	2009	**2008**	**2007**
Reserve Data:			
Proved developed reserves:			
Oil (MBbls)	8,814	9,235	13,552
Natural gas (MMcf)	46,159	57,635	50,990
Natural gas liquids (MBbls)	2,788	2,705	2,565
Total (MBoe)	19,295	21,546	24,615
PV-10 Value (in thousands)	$ 222,516	$ 233,061	$ 593,300

	As of December 31,		
	2009	**2008**	**2007**
Total Proved reserves:			
Oil (MBbls)	14,067	14,285	19,544
Natural gas (MMcf)	89,227	96,952	93,358
Natural gas liquids (MBbls)	4,983	4,325	4,271
Total (MBoe)	33,922	34,769	39,375
PV-10 Value (in thousands)	$ 336,053	$ 322,131	$ 911,549
Prices used in calculating PV-10 Value:			
$/Bbl (Oil)	$ 58.63	$ 44.15	$ 93.90
$/Mcf	$ 3.76	$ 5.33	$ 7.00
$/Bbl (NGL)	$ 31.03	$ 23.59	$ 54.69

The prices used in calculating the PV-10 values are net of the appropriate market differentials and are for the economic life of the properties.

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The following is a summary of the standardized measure of discounted net cash flows using methodology provided for in Topic 932 of the Accounting Standards Codification (the Codification) implemented by the Financial Accounting Standards Board, related to our estimated proved oil and natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves for the year ended December 31, 2009 were computed using benchmark prices based on the unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas during each month of 2009, as required by SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*, effective December 31, 2009, while estimated cash flows in the reserve reports at December 31, 2007 and 2008 were based on oil and natural gas spot prices as of the end of the period presented. Future development and production costs attributable to the proved reserves were estimated assuming that existing conditions would continue over the economic lives of the individual leases and costs were not escalated for the future. Estimated future income tax expenses were calculated by applying future statutory tax rates (based on the current tax law adjusted for permanent differences and tax credits) to the estimated future pretax net cash flows related to proved oil and natural gas reserves, less the tax basis of the properties involved. For further information regarding the standardized measure of discounted net cash flows related to our estimated proved oil and natural gas reserves for the years ended December 31, 2009, 2008 and 2007, please review Note M in the notes to our year-end 2009 financial statements appearing elsewhere in this report. The standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves at December 31 is summarized as follows:

	Year ended December 31,		
	2009	2008 (in thousands)	2007
Future cash inflows	$ 1,314,714	$ 1,253,537	$ 2,722,099
Future production costs	(535,784)	(472,191)	(824,576)
Future development costs	(148,956)	(145,086)	(146,734)
Future income tax expenses	(123,943)	(103,434)	(574,169)
Future net cash flows	506,031	532,826	1,176,620
10% annual discount for estimated timing of cash flows	(231,797)	(248,373)	(578,225)
Standardized measure of discounted future net cash flows	$ 274,234	$ 284,453	$ 598,395

We believe that PV-10 Value before income taxes, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions due to tax characteristics, which can differ significantly, among comparable companies. The standardized measure represents the PV-10 Value after giving effect to income taxes. The following table provides a reconciliation of our PV-10 Value to our standardized measure:

	At December 31,		
	2009	2008 (in thousands)	2007
PV-10 Value	$ 336,053	$ 322,131	$ 911,549
Future income taxes	(123,943)	(103,434)	(574,169)
Discount of future income taxes at 10% per annum	62,124	65,756	261,015
Standardized Measure	$ 274,234	$ 284,453	$ 598,395

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Except to the extent we acquire properties containing proved reserves or conduct successful exploration and development activities, our proved reserves will decline as reserves are produced. Our future oil and natural gas production is, therefore, highly dependent upon our level of success in finding or acquiring additional reserves.

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Net Production, Unit Prices and Costs

The following table presents certain information with respect to our oil and natural gas production and prices and costs attributable to all oil and natural gas properties owned by us for the periods shown. Average realized prices reflect the actual realized prices received by us, before and after giving effect to the results of our derivative contracts. Our derivative contracts are financial, and our production of oil, natural gas and NGLs, and the average realized prices we receive from our production, are not affected by our derivative contracts.

	Year ended December 31,		
	2009	**2008**	**2007 (1)**
Production volumes:			
Oil (MBbls)	1,138	1,187	774
Natural gas liquids (MBbls)	406	354	184
Natural gas (MMcf)	5,994	6,082	2,785
Total (MBoe)	2,542	2,554	1,422
Average realized prices (before effects of derivative contracts):			
Oil (per Bbl)	$ 58.24	$ 98.59	$ 71.11
Natural gas liquids (per Bbl)	27.26	50.24	49.16
Natural gas (per Mcf)	3.47	7.87	6.40
Total per Boe	38.62	71.52	57.60
Effect of settlement of derivative contracts:			
Oil (per Bbl)	$ 4.94	$ (8.84)	$ (4.35)
Natural gas liquids (per Bbl)			
Natural gas (per Mcf)	2.27		.25
Total per Boe	7.57	(4.10)	(1.88)
Average realized prices (after effects of derivative contracts):			
Oil (per Bbl)	$ 63.18	$ 89.75	$ 66.77
Natural gas liquids (per Bbl)	27.26	50.24	49.16
Natural gas (Per Mcf)	5.74	7.87	6.65
Total per Boe	46.19	67.42	55.72
Expenses (per Boe):			
Oil and natural gas production taxes	$ 2.09	$ 4.10	$ 3.43
Oil and natural gas production expenses	14.73	14.89	15.18
Amortization of full cost pool	12.06	17.89	12.86
General and administrative	6.56	7.95	8.36
Cash interest	5.28	10.11	11.91
Cash taxes	0.12	0.27	0.01
Impairment	18.73	105.66	

(1) Includes data with respect to Ascent Energy from November 29, 2007 through December 31, 2007.

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Fields containing 15% or more of total proved reserves at December 31, 2009:

	Year ended December 31,		
	2009	**2008**	**2007**
La Copita:			
Production volumes:			
Oil (MBbls)	58	42	22
Natural gas liquids (MBbls)	118	112	82
Natural gas (MMcf)	1,586	1,670	1,174
Total (MBoe)	441	433	300
Average realized prices:			
Oil (per Bbl)	$ 58.41	$ 103.45	$ 69.27
Natural gas liquids (per Bbl)	29.28	46.36	45.08
Natural gas (per Mcf)	3.95	8.91	6.79
Total per Boe	29.78	56.47	44.04
Oil and natural gas production expenses (per Boe)	$ 3.62	$ 4.68	$ 7.24

	Year ended December 31,		
	2009	**2008**	**2007**
Electra/Burkburnett:			
Production volumes:			
Oil (MBbls)	537	560	577
Natural gas liquids (MBbls)	70	91	83
Natural gas (MMcf)			
Total (MBoe)	607	651	660
Average realized prices:			
Oil (per Bbl)	$ 57.99	$ 99.05	$ 70.01
Natural gas liquids (per Bbl)	27.85	42.22	34.39
Natural gas (per Mcf)			
Total per Boe	54.51	91.15	65.53
Oil and natural gas production expenses (per Boe)	$ 22.46	$ 22.71	$ 19.47

Acquisition, Development and Exploration Capital Expenditures

The following table presents information regarding our net costs incurred in our acquisitions of proved and unproved properties, and our development and exploration activities (in thousands):

	Year ended December 31,		
	2009	**2008**	**2007 (1)**
Proved property acquisition costs	$ 1,311	$ 10,091	$ 299,573
Unproved property acquisition costs		2,691	24,642
Development costs	28,239	57,084	12,921
Exploration costs	321	14,857	7,659
Total costs incurred	$ 29,871	$ 84,723	$ 344,795

(1) Includes data with respect to Ascent Energy from November 29, 2007 through December 31, 2007.

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Finding Costs

The following table sets forth the estimated proved reserves we acquired or discovered, including revisions of previous estimates, during each stated period. In calculating finding costs, we include acquisition costs related to proved property acquisitions, development costs, and exploration costs with respect to exploratory wells drilled and completed.

	Year ended December 31,		
	2009	2008	2007 (1)
Proved reserves acquired/discovered (MBoe)	3,957	4,984	19,973
Total cost per Boe of reserves acquired/discovered	$ 7.55	$ 17.00	$ 17.26

(1) Includes data with respect to Ascent properties from November 29, 2007 to December 31, 2007.

Producing Wells

The following table sets forth the number of productive wells in which we owned an interest as of December 31, 2009. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline connections or connection to production facilities. Wells that we complete in more than one producing horizon are counted as one well.

	Gross	Net
Oil	2,755	2,166
Natural gas	686	363
Total	3,441	2,529

Acreage

The following table sets forth our developed and undeveloped gross and net leasehold acreage as of December 31, 2009:

	Gross	Net
Developed	142,623	68,458
Undeveloped	240,792	91,222
Total	383,415	159,680

Approximately 75% of our net acreage was located in our core areas as of December 31, 2009. Our undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether or not such acreage is held by production or contains proved reserves. A gross acre is an acre in which we own an interest. A net acre is deemed to exist when the sum of fractional ownership interests in gross acres equals one. The number of net acres is the sum of the fractional interests owned in gross acres.

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Drilling Activities

During the periods indicated, we drilled or participated in drilling the following wells:

	Year Ended December 31,					
	2009 (1)		2008 (2)		2007 (3)	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	45	44	83	66.8	52	52.0
Non-productive	1	0.9	1	0.2	5	5.0
Exploratory wells:						
Productive			6	5.1	11	2.0
Non-productive					2	.4
Total	46	44.9	90	72.1	70	59.4

(1) Does not include 3 gross (0.16 net) wells that were in the process of being completed at December 31, 2009 and does not include 2 gross (1 net) wells that were drilled in 2008 and waiting on pipeline connection.
(2) Does not include 7 gross (5.8 net) wells that were in the process of being completed at December 31, 2008.
(3) Does not include 11 gross (9 net) wells that were in the process of being completed at December 31, 2007.

Ascent Acquisition

On November 29, 2007, we acquired Ascent Energy in a cash and stock transaction valued at $303.8 million. Ascent was an independent oil and natural gas company engaged in the acquisition, exploration and development of both conventional and unconventional oil and natural gas properties in Texas, Oklahoma, Louisiana and the Appalachian region of West Virginia. The total consideration paid by us in connection with our acquisition of Ascent included 18,783,344 shares of our common stock, warrants to purchase 6,200,000 shares of our common stock at an exercise price of $5.00 per share, most of which were exercised prior to their expiration on May 11, 2008, and $203.0 million in cash (including $1.3 million of direct acquisition costs). The Ascent acquisition added 18.6 MMBoe of proved reserves and approximately 3,000 Boe per day of current production, together with a significant number of additional drilling locations and further development opportunities.

Oil and Natural Gas Marketing and Derivative Activities

During the year ended December 31, 2009, Shell Trading (US) Company, or STUSCO, accounted for $59.5 million, or 61%, of our oil and natural gas revenue for that period. No other purchaser accounted for 10% or more of our oil and natural gas revenue during 2009. Our agreement with STUSCO covers all of our North Texas oil production. Effective August 1, 2008 through January 31, 2009, our agreement provided for payment, on a per barrel basis, of a price equal to STUSCO s posted price for North Texas Sweet plus a premium of $3.25. Effective February 1, 2009, our price changed to STUSCO s posted price for North Texas Sweet, plus or minus Platts Trade-month P+ (a fluctuating premium based on petroleum stock levels and refinery demand), minus $1.50. Effective July 1, 2009, our price changed to STUSCO s posted price for West Texas Intermediate, plus a premium of $0.80.

There are other purchasers in the fields and such other purchasers would be available to purchase our production should our current purchaser discontinue operations. We have no reason to believe that any such cessation is likely to occur.

To reduce exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow, we periodically utilize various derivative strategies to manage the price received for a portion of our future oil and natural gas production. The notional volumes under our derivative contracts do not exceed our expected production. Our derivative strategies customarily involve the purchase of put options to provide a price floor for our production, put/call collars that establish both a floor and a ceiling price to provide price certainty within a fixed range, call options that establish a secondary floor above a put/call collar ceiling, or swap arrangements that establish an index-related price above which we pay the derivative counterparty and below which we are paid by the derivative counterparty. These contracts allow us to predict with greater certainty the effective oil and natural gas prices to be received for our production and benefit us when market prices are less than the base floor prices or swap prices under our derivative contracts. However, we will not benefit from market prices that are higher than the ceiling or swap prices in these contracts for our hedged production.

See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for further information about our derivative positions at December 31, 2009.

Competition

The oil and natural gas industry is highly competitive. We compete for the acquisition of oil and natural gas properties, primarily on the basis of the price to be paid for such properties, with numerous entities including major oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well-established companies and have financial and other resources substantially greater than ours. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Title to Properties

We believe that we have satisfactory title to our properties in accordance with standards generally accepted in the oil and natural gas industry. As is customary in the oil and natural gas industry, we make only a cursory review of title to farmout acreage and to undeveloped oil and natural gas leases upon execution of any contracts. Prior to the commencement of drilling operations, a title examination is conducted and curative work is performed with respect to significant defects. To the extent title opinions or other investigations reflect title defects, we, rather than the seller of the undeveloped property, typically are responsible to cure any such title defects at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent for us to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We have obtained title opinions or reports on substantially all of our producing properties. Prior to completing an acquisition of producing oil and natural gas leases, we perform a title review on a material portion of the leases. Our oil and natural gas properties are subject to customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use of or affect the value of such properties.

Facilities

Our executive and operating offices are located at Suite 650, Meridian Tower, 5100 E. Skelly Drive, Tulsa, Oklahoma 74135 which we occupy under a lease with a remaining term ending in January 2014, at an annual rental of approximately $0.4 million, subject to escalations for taxes and utilities. As a result of the Ascent acquisition, we acquired an executive and operating office at 4965 Preston Park Blvd., Suite 800, in Plano, Texas, subject to a lease extending through 2014. Currently, rent under the lease is approximately $0.7 million annually. We have subleased a portion of our Plano office and will receive approximately $0.1 million annually beginning in June 2010. We also lease a small office in Houston, Texas. We believe that our facilities are adequate for our current needs.

Regulation

General. Various aspects of our oil and gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and gas industry and our individual members.

Regulation of Sales and Transportation of Natural Gas. The Federal Energy Regulatory Commission, or the FERC, regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. In the past, the federal government has regulated the prices at which natural gas can be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation and proposed regulation designed to increase competition within the natural gas industry, to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers and to establish the rates interstate pipelines may charge for their services. Similarly, the Oklahoma Corporation Commission and the Texas Railroad Commission have been reviewing changes to their regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes being considered by these federal and state regulators would affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that any actions taken will have an effect materially different than the effect on other natural gas producers with which we compete.

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

Oil Price Controls and Transportation Rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The price we receive from the sale of these products may be affected by the cost of transporting the products to market.

Environmental. Our oil and natural gas operations are subject to pervasive federal, state, and local laws and regulations concerning the protection and preservation of the environment (e.g., ambient air, and surface and subsurface soils and waters), human health, worker safety, natural resources and wildlife. These laws and regulations affect virtually every aspect of our oil and natural gas operations, including our exploration for, and production, storage, treatment, and transportation of, hydrocarbons and the disposal of wastes generated in connection with those activities. These laws and regulations increase our costs of planning, designing, drilling, installing, operating, and abandoning oil and natural gas wells and appurtenant properties, such as gathering systems, pipelines, and storage, treatment and salt water disposal facilities.

In December 2009, the EPA promulgated a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas (GHG) regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, in September 2009, the EPA also promulgated a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. These regulations may apply to our operations. The EPA has proposed two other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and gas exploration and production industry and pipeline industry.

The GHG reporting rule and the proposed rules to regulate the emissions of GHGs would result in federal regulation of carbon dioxide emissions and other GHGs, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry. See Risk factors Risks relating to our business Regulation related to greenhouse gas emissions could have an adverse effect on our operations and demand for oil and natural gas.

We have expended and will continue to expend significant financial and managerial resources to comply with applicable environmental laws and regulations, including permitting requirements. Our failure to comply with these laws and regulations can subject us to substantial civil and criminal penalties, claims for injury to persons and damage to properties and natural resources, and clean-up and other remedial obligations. Although we believe that the operation of our properties generally complies with applicable environmental laws and regulations, the risks of incurring substantial costs and liabilities are inherent in the operation of oil and natural gas wells and appurtenant properties. We could also be subject to liabilities related to the past operations conducted by others at properties now owned by us, without regard to any wrongful or negligent conduct by us.

We cannot predict what effect future environmental legislation and regulation will have upon our oil and natural gas operations. The possible legislative reclassification of certain wastes generated in connection with oil and natural gas operations as hazardous wastes would have a significant impact on our operating costs, as well as the oil and natural gas industry in general. The cost of compliance with more stringent environmental laws and regulations, or the more vigorous administration and enforcement of those laws and regulations, could result in material expenditures by us to remove, acquire, modify, and install equipment, store and dispose of wastes, remediate facilities, employ additional personnel, and implement systems to ensure compliance with those laws and regulations. These accumulative expenditures could have a material adverse effect upon our profitability and future capital expenditures.

Regulation of Oil and Gas Exploration and Production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells, and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties.

Employees

At December 31, 2009, we had 195 employees, of whom 38 were administrative, accounting or financial personnel and of whom 157 were technical and operations personnel. Our exploration staff includes three exploration geologists and six landmen. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreement and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Available Information

Copies of our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are available free of charge through our website (www.ramenergy.com) as soon as reasonably practicable after we electronically file the material with, or furnish it to, the SEC. Our SEC filings are also available from the SEC s website at: http://www.sec.gov. The references to our website address do not constitute incorporation by reference of the information contained on the website and should not be considered part of this report.

Item 3. ***Legal Proceedings***

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. Other than the litigation matters described below, we are not involved in any legal proceedings, nor are we a party to any pending or threatened claims, that could reasonably be expected to have a material adverse effect on our financial condition or results of operations.

Sacket v. Great Plains Pipeline Company, et al., District Court of Woods County, Oklahoma (Case No. CJ-2002-70). This was a class action lawsuit on behalf of certain royalty owners in which RAM Energy, together

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with certain of its subsidiaries and affiliates, were defendants. In the lawsuit, the plaintiff alleged that the royalty payments to landowners for oil and natural gas produced from wells connected to a RAM Energy subsidiary s natural gas, oil and saltwater pipeline system in Woods, Alfalfa and Major Counties, Oklahoma, were calculated on a price that was lower than the price at which the production from the related wells was resold by the subsidiary. RAM Energy and its subsidiaries sold their interests in the affected leases effective December 1, 2001.

On September 18, 2008, we, together with the other defendants in the lawsuit, entered into a settlement agreement with the plaintiff, individually and as representative of the putative class, pursuant to which the defendants agreed to pay an aggregate $25.0 million in settlement of the lawsuit. RAM Energy and its subsidiaries agreed to pay $16.0 million of the settlement amount, with the unrelated third party defendants paying the remaining $9.0 million. On March 5, 2009, following a hearing at which the Court received evidence concerning the fairness of the proposed settlement to the plaintiff class, the Court entered an order approving the settlement and the related plan of allocation and distribution of the settlement fund. On April 4, 2009, the settlement became final, promptly after which the plan of distribution was implemented and the settlement funds distributed to the members of the plaintiff class.

In conjunction with our May 8, 2006 acquisition of RAM Energy, the former stockholders of RAM Energy deposited in escrow 3,200,000 shares of our common stock to secure their potential indemnity obligations to us, including any loss we might sustain in the pending litigation. Under the terms of the escrow agreement, the former stockholders of RAM Energy had the option of substituting cash for all or a portion of their escrowed shares, based on the average closing price of our common stock for the ten trading days ending on the last trading day prior to the date our indemnity claim against the escrow is paid, in which event the escrowed shares for which cash is substituted would be delivered to the stockholders and the cash paid to us out of the escrow. During 2008, we recorded a contingent liability of $16.0 million for our share of the settlement amount and a receivable of $2.8 million representing the value of the escrowed shares based on the closing price of $0.88 per share on December 31, 2008.

On April 7, 2009, we made a claim against the escrow for all of the escrowed shares. Also on April 7, 2009, the former stockholders of RAM Energy notified the escrow agent that they would substitute cash, at a fair market value of $0.74 per share (determined pursuant to the terms of the escrow agreement), for a total of 316,190 shares of their Company common stock held in escrow. On April 8, 2009, the escrow agent initiated the transfer to us, in satisfaction of the indemnification obligation of the former RAM Energy stockholders, of a total of 2,883,810 shares of our common stock and $233,980 in cash, less the fees and expenses of the escrow agent. These transactions concluded the settlement and closed the escrow. In the first quarter of 2009, we recorded a charge to other expense of $0.4 million and adjusted the receivable from $2.8 million to $2.4 million to reflect the $0.74 per share market value of the escrow shares on the final settlement date.

Rathborne Land Company, et al., v. Ascent Energy Inc., *et al.*, United States District Court for the Eastern District of Louisiana (Case No. 05-2452). In this lawsuit, Ascent Energy Inc. and its Ascent Energy Louisiana, LLC subsidiary were sued for lease cancellation and damages for failure to explore and develop the plaintiff s lease. By Opinion dated December 31, 2008, the Court found in favor of the plaintiff and against the defendants. On June 1, 2009, the court entered judgment in favor of the plaintiff and against the defendants in the amount of $4.6 million, and shortly thereafter we filed an appeal with the United States Court of Appeals for the Fifth Circuit. The appeal is currently pending.

In conjunction with our November 29, 2007 acquisition of Ascent, the former stockholders and note holders of Ascent deposited $20.0 million in escrow to secure their obligation to indemnify us with respect to certain liabilities and obligations of Ascent, including any loss, cost, liability or expense we might incur in connection with this and other pending litigation, subject to a sharing arrangement. After giving effect to such sharing arrangement with respect to previously settled litigation, we and the former Ascent owners will share equally the first $1.8 million of any losses attributable to this lawsuit and the former Ascent owners, out of the escrow, will bear the remaining portion of any loss so incurred, up to the remaining balance in the escrow fund. On June 18, 2009, we arranged for the posting of a cash security bond with the registry of the trial court in the amount of $5.5 million, being 120% of the amount of the judgment, as required by court rule. By agreement with the representative of the former Ascent stockholders and note holders, we posted the sum of $0.9 million toward the security deposit and the remaining sum of $4.6 million was posted out of the escrow fund. All remaining funds in the escrow account, less the sum of approximately $0.2 million (which was retained in the escrow account to cover additional and incidental fees and expenses related to this litigation), were distributed to the Ascent stockholders and note holders per the terms of the escrow agreement. During the fourth quarter of 2008, we recorded a contingent liability of $0.9 million related to this litigation.

Item 4. ***Reserved***

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PART II

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

Market for Common Stock

Our common stock is traded on the Nasdaq Capital Market under the symbol RAME. The following table sets forth the range of high and low closing bid prices for our common stock for the periods indicated.

	Common Stock	
	High	**Low**
2010:		
First Quarter (through March 9, 2010)	$ 2.23	$ 1.49
2009:		
First Quarter	$ 1.24	$ 0.40
Second Quarter	1.09	0.68
Third Quarter	1.30	0.64
Fourth Quarter	2.24	1.41
2008:		
First Quarter	$ 5.10	$ 4.42
Second Quarter	6.73	4.80
Third Quarter	6.40	2.68
Fourth Quarter	2.75	0.74
2007:		
First Quarter	$ 5.57	$ 4.00
Second Quarter	5.56	4.25
Third Quarter	5.64	4.17
Fourth Quarter	5.46	4.65

Holders

As of March 3, 2010, there were 89 holders of record of our common stock. We believe that at March 3, 2010, there were 6,180 beneficial holders of our common stock.

Dividends

It is the present intention of our board of directors to retain all earnings, if any, for use in our business operations and, accordingly, our board does not anticipate declaring any dividends in the foreseeable future.

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Compensation Plan Information

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2009, under which our equity securities were authorized for issuance:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders (1)	2,363,993(2)	$ 2.64(3)	2,409,426(4)
Equity compensation plans not approved by security holders			
Total	2,363,993	$ 2.64	2,409,426

(1) Shares awarded under all above plans may be newly issued, from our treasury or acquired in the open market.

(2) This number represents shares of unvested restricted stock awards issued and outstanding under our 2006 Long-Term Incentive Plan as of December 31, 2009.

(3) This represents the weighted average market price on the date of grant of shares of restricted stock issued under our 2006 Long-Term Incentive Plan.

(4) This number reflects shares available for issuance under our 2006 Long-Term Incentive Plan as of December 31, 2009.

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Stockholder Return Performance Presentation

The following graph and table compare the cumulative 5-year total return provided to our stockholders on our common stock beginning December 31, 2004 through December 31, 2009, relative to the cumulative total returns of the Nasdaq Composite index and the Dow Jones Wilshire MicroCap Exploration & Production index. The comparison assumes an investment of $100 (with reinvestment of all dividends) was made in our common stock on December 31, 2004 and in each of the indexes and its relative performance is tracked through December 31, 2009. The identity of the 50+ companies included in the Dow Jones Wilshire MicroCap Exploration & Production Index will be provided upon request.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
RAM Energy Resources, Inc.	$ 40	$ 19	$ 107	$ 117	$ 117
Nasdaq Composite	106	83	142	129	116
Dow Jones Wilshire MicroCap Exploration & Production Index	54	48	133	194	164

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

We acquired RAM Energy effective May 8, 2006, by the merger of our wholly owned subsidiary with and into RAM Energy. For accounting and financial reporting purposes, the merger was accounted for as a reverse acquisition and, in substance, as a capital transaction, because we had no active business operations prior to consummation of the merger. Accordingly, for accounting and financial reporting purposes, the RAM Energy acquisition was treated as the equivalent of RAM Energy issuing stock for our net monetary assets accompanied by a recapitalization. Our net monetary assets have been stated at their fair value, essentially equivalent to historical costs, with no goodwill or other intangible assets recorded. The accumulated deficit of RAM Energy has been carried forward. Operations prior to the merger are those of RAM Energy.

We acquired Ascent Energy Inc. on November 29, 2007, by the merger of our wholly owned subsidiary with and into Ascent. The Ascent acquisition was accounted for under the purchase method of accounting. Upon completion of the Ascent acquisition, Ascent adopted the full cost method of accounting for exploration, development and production of oil and natural gas.

The selected consolidated financial information presented below should be read in conjunction with our consolidated financial statements and the related notes, and *Management s Discussion and Analysis of Financial Condition and Results of Operations* contained elsewhere in this report. Our financial position and results of operations for 2009, 2008 and 2007 may not be comparative to other periods as a result of certain divestitures and acquisitions, as more fully described in our consolidated financial statements included elsewhere in this report.

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Selected Financial Data

(in thousands, except share data)

	Year Ended December 31,				
	2009	2008	2007 (1)	2006	2005
Revenues and Other Operating Income:					
Oil sales	$ 66,281	$ 117,036	$ 55,000	$ 48,013	$ 42,322
Natural gas sales	20,818	47,884	17,830	14,232	17,728
Natural gas liquids sales	11,068	17,770	9,047	5,770	6,193
Realized gains (losses) on derivatives	19,255	(10,472)	(2,669)	(4,650)	(5,393)
Unrealized gains (losses) on derivatives	(30,561)	33,257	(10,056)	6,239	(6,302)
Other	217	382	488	640	851
Total revenues and other operating income	87,078	205,857	69,640	70,244	55,399
Operating Expenses:					
Oil and natural gas production taxes	5,320	10,480	4,869	3,329	3,320
Oil and natural gas production expenses	37,455	38,030	21,574	18,266	16,099
Depreciation and amortization	31,650	46,512	18,948	13,252	12,972
Accretion expense	1,976	2,207	704	535	510
Impairment	47,613	269,886			
Share-based compensation	2,179	2,563	989	2,308	
General and administrative, net of operator s overhead fees	16,667	20,305	11,891	9,300	8,610
Total operating expenses	142,860	389,983	58,975	46,990	41,511
Operating income (loss)	(55,782)	(184,126)	10,665	23,254	13,888
Other Income (Expense):					
Interest expense	(18,590)	(24,182)	(20,757)	(17,050)	(12,614)
Interest income	82	208	1,047	309	75
Other expense	(440)	(13,536)	(57)		
Income (Loss) Before Income Taxes	(74,730)	(221,636)	(9,102)	6,513	1,349
Income Tax Provision (Benefit)	(16,347)	(91,683)	(7,852)	1,465	806
Net income (loss)	$ (58,383)	$ (129,953)	$ (1,250)	$ 5,048	$ 543

(1) We acquired Ascent Energy Inc. in November 2007.

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Selected Financial Data (continued)

(in thousands, except share data)

	Year Ended December 31,				
	2009	2008	2007 (1)	2006	2005
Cash dividends per share	$	$	$	$ 0.02	$ 0.05
Earnings (loss) per share:					
Basic	$ (0.75)	$ (1.80)	$ (0.03)	$ 0.16	$ 0.02
Diluted	(0.75)	(1.80)	(0.03)	0.16	0.02
Weighted average shares outstanding:					
Basic	77,601,057	72,234,750	42,087,617	30,900,213	26,492,286
Diluted	77,601,057	72,234,750	42,087,617	32,119,169	26,492,286
Statement of Cash Flow Data					
Cash provided by (used in):					
Operating activities	$ 32,372	$ 74,454	$ 17,042	$ 29,660	$ 18,359
Investing activities	(23,921)	(82,568)	(241,192)	(25,317)	(12,554)
Financing activities	(8,486)	1,405	224,302	2,308	(6,910)
Other Data					
Capital expenditures (2)	$ 29,871	$ 84,723	$ 344,795	$ 28,145	$ 13,528
Modified EBITDA	58,287	103,641	42,352	33,419	33,747

	As of December 31,				
	2009	2008	2007(1)	2006	2005
Balance Sheet Data					
Total assets	$ 311,162	$ 403,964	$ 580,242	$ 161,725	$ 143,276
Long-term debt, including current portion	246,167	250,696	335,747	132,237	112,846
Stockholders equity (deficit)	(526)	57,840	98,698	(27,895)	(20,769)

(1) We acquired Ascent Energy Inc. in November 2007.
(2) Includes costs of acquisitions.

Our Modified EBITDA is determined by adding the following to net income (loss): interest expense, amortization and depreciation, accretion, income taxes, share-based compensation, impairment charges, settlement charges and unrealized gains (losses) on derivatives. The table below reconciles Modified EBITDA to net income (loss).

We present Modified EBITDA because we believe that it provides useful information regarding our continuing operating results. We rely on Modified EBITDA as a measure to review and assess our operating performance with corresponding periods, and as an assessment of our overall liquidity and our ability to meet our debt service obligations.

We believe that Modified EBITDA is useful to investors to provide disclosure of our operating results on the same basis as that used by our management. We also believe that this measure can assist investors in comparing our performance to that of other companies on a consistent basis without regard to certain items that do not directly affect our ongoing operating performance or cash flows. Modified EBITDA, which is not a financial measure under generally accepted accounting principles, or GAAP, has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for net income, cash flows from operating activities and other consolidated income or cash flows statement data prepared in accordance with GAAP. Because of these limitations, Modified EBITDA should neither be considered as a measure of discretionary cash available to

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us to invest in the growth of our business, nor as a replacement for net income. We compensate for these limitations by relying primarily on our GAAP results and using Modified EBITDA as supplemental information.

	Year ended December 31,				
	2009	2008	2007	2006	2005
	(in thousands)				
Reconciliation of Modified EBITDA to net income (loss):					
Net income (loss)	$ (58,383)	$ (129,953)	$ (1,250)	$ 5,048	$ 543
Plus: Interest expense	18,590	24,182	20,757	17,050	12,614
Plus: Amortization and depreciation expense	31,650	46,512	18,948	13,252	12,972
Plus: Accretion expense	1,976	2,207	704	535	510
Plus: Income tax expense (benefit)	(16,347)	(91,683)	(7,852)	1,465	806
Plus: Share-based compensation	2,179	2,563	989	2,308	
Plus: Impairment charges	47,613	269,886			
Plus: Settlement charge	448	13,184			
Plus: Unrealized (gain) loss on derivatives	30,561	(33,257)	10,056	(6,239)	6,302
Modified EBITDA	$ 58,287	$ 103,641	$ 42,352	$ 33,419	$ 33,747

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

General

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Louisiana and Oklahoma. Through our RAM Energy subsidiary, we have been active in our core producing areas of Texas, Louisiana and Oklahoma since 1987. Our management team has extensive technical and operating expertise in all areas of our geographic focus.

Prior to May 8, 2006, our corporate name was Tremisis Energy Acquisition Corporation. On May 8, 2006, we acquired RAM Energy through the merger of our wholly owned subsidiary into RAM Energy. The RAM Energy acquisition was accomplished pursuant to the terms of an Agreement and Plan of Merger dated October 20, 2005, as amended, among us, our acquisition subsidiary, RAM Energy and the stockholders of RAM Energy. Upon completion of the RAM Energy acquisition, RAM Energy became our wholly owned subsidiary and we changed our name from Tremisis Energy Acquisition Corporation to RAM Energy Resources, Inc.

The RAM Energy acquisition was accounted for as a reverse acquisition. RAM Energy was treated as the acquiring company and the continuing reporting entity for accounting purposes. Upon completion of the merger, our assets and liabilities were recorded at their fair value, which is considered to approximate historical cost, and added to those of RAM Energy. Because we had no active business operations prior to consummation of the merger, the merger was accounted for as a recapitalization of RAM Energy.

On February 13, 2007, we consummated a public offering of 7,500,000 shares of our common stock and received net proceeds of $28.1 million.

On November 29, 2007, we consummated our acquisition of Ascent for a total consideration that included 18,783,344 shares of our common stock and warrants to purchase 6,200,000 shares of our common stock at an exercise price of $5.00 per share at any time prior to May 11, 2008, and $203.0 million in cash (including $1.3 million of direct acquisition costs), of which $20.0 million was deposited in escrow. The total consideration included amounts paid to certain holders of Ascent s outstanding indebtedness, amounts necessary to settle and close all of Ascent s outstanding oil and natural gas hedging contracts, and payments to holders of Ascent s outstanding preferred stock and common stock.

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Effective May 12, 2008, warrants to purchase 17,617,331 shares of our common stock (including certain of the warrants issued in connection with the Ascent acquisition) were exercised at an exercise price of $5.00 per share. The exercise of these warrants resulted in net proceeds to us of $86.6 million. Proceeds of the exercise were used to pay down the term loan portion of our credit facility. An additional 1,231,469 warrants expired on that same date and are no longer outstanding.

Oil and natural gas prices have historically been volatile. In 2009, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $58.24 per Bbl and $3.47 per Mcf compared with 2008 average realized prices of $98.59 per Bbl and $7.87 per Mcf. While the annual average prices for oil and natural gas during 2008 exceeded 2007 average prices, the fourth quarter of 2008 experienced significant declines in prices for both commodities. Spot natural gas prices declined to $5.71 per Mcf on December 31, 2008 from $12.27 per Mcf on June 30, 2008, a decrease of approximately 53%. Oil prices in the last six months of 2008 experienced a 68% decrease, declining to $44.60 per Bbl on December 31, 2008 from $138.32 per Bbl on June 30, 2008. Natural gas and oil prices continued to decline into the first quarter of 2009. The volatile commodity price environment from 2006 through the third quarter of 2008 was characterized by an upward trend, which created a competitive environment for drilling rigs, oil field services, labor and tubular goods. Accordingly, prices for these products and services also increased. The rapid declines in oil and natural gas prices beginning late in the third quarter of 2008 have created an environment, particularly with drilling rigs and oil field services, where demand has fallen in certain areas. Prices improved in the fourth quarter of 2009 for oil, increasing 28% to $73.36 per Bbl compared to $57.56 in the 2008 period. Natural gas prices continued to decline to $3.93 per Mcf in the fourth quarter of 2009 from $5.05 in the fourth quarter of 2008, a 22% drop. It is impossible to predict the duration or outcome of these price declines or the long-term impact on drilling and operating costs and the impacts, whether favorable or unfavorable, to our results of operations and liquidity. We continue to monitor operations and planned capital budget expenditures as the economics of many projects have diminished as a result of commodity price declines.

Critical Accounting Policies

The preparation of our financial statements in conformity with generally accepted accounting principles requires our management to make estimates and assumptions that affect our reported assets, liabilities and contingencies as of the date of the financial statements and our reported revenues and expenses during the related reporting period. Our actual results could differ from those estimates. See Note A to our consolidated financial statements included in Item 8 of this report for further discussions of our significant accounting policies and recently adopted accounting standards.

We follow the full cost method of accounting for oil and natural gas operations. Under this method all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of oil and natural gas reserves are capitalized. No gains or losses are recognized upon the sale or other disposition of oil and natural gas properties except in transactions that would significantly alter the relationship between capitalized costs and proved reserves. The costs of unevaluated oil and natural gas properties are excluded from the amortizable base until the time that either proven reserves are found or it has been determined that such properties are impaired. As properties become evaluated, the related costs transfer to proved oil and natural gas properties using full cost accounting.

Under the full cost method the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed the estimated after-tax future net revenues from proved oil and natural gas properties, discounted at 10% (the Ceiling Limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, and certain production-related and ad valorem taxes are deducted. In calculating future net revenues, prices and costs are held constant indefinitely, except for changes that are fixed and determinable by existing contracts. The net book value is compared to the Ceiling Limitation on a quarterly and yearly basis. The excess, if any, of the net book value above the Ceiling Limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. At December 31, 2008, the net book value of our

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oil and natural gas properties exceeded the Ceiling Limitation resulting in reduction in the carrying value of our oil and natural gas properties by $269.4 million, or $171.6 million net of tax, and at March 31, 2009, the net book value of our oil and natural gas properties exceeded the Ceiling Limitation resulting in reduction in the carrying value of our oil and natural gas properties by $47.6 million, or $30.3 million net of tax.

Estimates of our crude oil and natural gas reserves are prepared by independent petroleum and geological engineers in accordance with guidelines established by the SEC. Proved reserves, estimated future net revenues and the present value of our reserves are estimated based upon a combination of historical data and estimates of future activity. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Estimates of proved crude oil and natural gas reserves may significantly affect the amount at which oil and natural gas properties are recorded and significantly affect our amortization and depreciation expense.

On December 31, 2008, the SEC issued Release No. 33-8995 amending its oil and natural gas reporting requirements for oil and natural gas producing companies. Companies were not permitted to comply at an earlier date. Among other things, Release No. 33-8995:

- Revises a number of definitions relating to proved oil and natural gas reserves to make them consistent with the Petroleum Resource Management System, which includes certain non-traditional resources in proved reserves;
- Permits the use of new technologies for determining proved oil and natural gas reserves;
- Requires the use of average prices for the trailing twelve-month period in the estimation of oil and natural gas reserve quantities and, for companies using the full cost method of accounting, in computing the Ceiling Limitation, in place of a single day price as of the end of the fiscal year;
- Permits the disclosure in filings with the SEC of probable and possible reserves and reserves sensitivity to changes in prices;
- Requires additional disclosures (outside of the financial statements) regarding the status of undeveloped reserves and changes in status of these from period to period; and
- Requires a discussion of the internal controls in place to assure objectivity in the reserve estimation process and disclosure of the technical qualifications of the technical person having primarily responsibility for preparing the reserve estimates.

Our independent petroleum engineers utilized the new procedures in preparing the estimate of our proved reserves as of December 31, 2009, as reflected in this report.

Topic 410 of the Codification addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends Statement of Financial Accounting Standards No. 19, now Topic 932 of the Codification. Topic 410 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. We determine our asset retirement obligation by calculating the present value of the estimated cash flows related to the liability.

As set forth in Topic 740 of the Codification, deferred income taxes are recognized at each period end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. We routinely assess the realizability of our deferred tax assets. We consider future taxable income in making such assessments. 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, it is reduced by a

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valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods.

We account for our derivative arrangements as set forth in Topic 815 of the Codification. Topic 815 requires the accounting recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We may or may not elect to designate a derivative instrument as a hedge against changes in the fair value of an asset or a liability (a fair value hedge) or against exposure to variability in expected future cash flows (a cash flow hedge). The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated by us as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the statement of operations due to the fact that changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in the fair value are recognized in earnings. We have not elected to designate our derivative instruments as hedges as required by Topic 815 in order to receive hedge accounting treatment. Accordingly, all gains and losses on the derivative instrument have been recorded in earnings.

During June 2008, the FASB issued authoritative guidance on whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in computing basic earnings per share. The guidance was effective for fiscal years beginning after December 15, 2008, and interim periods within those years. Additionally, all prior period earnings per share must be adjusted retrospectively. As our restricted stock awards granted under our Long-Term Incentive Plan qualify as participating securities, we adopted the guidance during 2009, which resulted in an increase in our basic and diluted weighted average shares outstanding for the years ended December 31, 2009, 2008 and 2007. The impact of the adoption of the guidance is reflected in the following table:

	2009	2008	2007
Before adoption:			
Weighted average shares outstanding:			
Basic	75,251,399	70,629,452	41,240,021
Diluted	75,251,399	70,629,452	41,240,021
Earnings (loss) per share:			
Basic	$ (0.78)	$ (1.84)	$ (0.03)
Diluted	$ (0.78)	$ (1.84)	$ (0.03)
After adoption:			
Weighted average shares outstanding:			
Basic	77,601,057	72,234,750	42,087,617
Diluted	77,601,057	72,234,750	42,087,617
Earnings (loss) per share:			
Basic	$ (0.75)	$ (1.80)	$ (0.03)
Diluted	$ (0.75)	$ (1.80)	$ (0.03)

We account for share-based payments under authoritative guidance, as set forth in Topic 718 of the Codification. Topic 718 requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

We account for uncertain tax positions under the guidance set forth in Topic 740 of the Codification. This Topic prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the enterprise determines whether it is more

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likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based solely on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Results of Operations

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

Oil and natural gas sales decreased $84.5 million, or 46%, to $98.2 million for the year ended December 31, 2009 as compared to $182.7 million for the year ended December 31, 2008. This decrease was driven by commodity price decreases, which on a per Boe basis declined 46% for the year ended December 31, 2009 as compared to 2008.

The following tables summarize our oil and natural gas production volumes (in thousands), average sale prices and comparisons for the years ended December 31, 2009 and 2008:

	South Texas	Developing Fields Barnett Shale	Appalachia	Mature Oil Fields* Various	Mature Natural Gas Fields Various	Total
Year Ended December 31, 2009						
Aggregate Net Production						
Oil (MBbls)	62	8	1	957	110	1,138
NGLs (MBbls)	122	124		78	82	406
Natural Gas (MMcf)	2,105	780	81	595	2,433	5,994
MBoe	534	262	15	1,134	597	2,542
Year Ended December 31, 2008						
Aggregate Net Production						
Oil (MBbls)	49	7	1	977	153	1,187
NGLs (MBbls)	113	85		81	75	354
Natural Gas (MMcf)	2,587	576	62	1,046	1,811	6,082
MBoe	593	188	11	1,232	530	2,554
Change in MBoe	(59)	74	4	(98)	67	(12)
Percentage Change in MBoe	-9.9%	39.4%	36.4%	-8.0%	12.6%	-0.5%

* Includes Electra/Burkburnett, Allen/Fitts and Layton fields.

	Year ended December 31, 2009	Year ended December 31, 2008	(Decrease)
Average sale prices:			
Oil (per Bbl)	$ 58.24	$ 98.59	(40.9)%
NGL (per Bbl)	$ 27.26	$ 50.24	(45.7)%
Natural gas (per Mcf)	$ 3.47	$ 7.87	(55.9)%
Per Boe	$ 38.62	$ 71.52	(46.0)%

Production volumes were essentially flat during the year ended December 31, 2009 as compared to the year ended December 31, 2008. Production from our developing fields of South Texas, Barnett Shale, and Appalachia (West Virginia) increased by 19 MBoe in the current year due principally to a 39% increase in production from our Barnett Shale properties. Drilling activity included two gross (0.4 net) wells on our Tier 1 Barnett Shale acreage in 2009, with one gross (0.4 net) well completed as a producing well and one gross (0.04 net) well in the

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process of being completed at December 31, 2009. Production from our mature oil fields of Electra/Burkburnett in North Texas and Allen/Fitts in Pontotoc County, Oklahoma decreased by 98 MBoe over the prior year due to normal production declines and a reduced pace of drilling in those fields. We drilled 39 gross (39 net) wells in Electra/Burkburnett in 2009. Production from our mature gas field of Boonsville increased by 67 MBoe over the prior year. Drilling activity included one gross (one net) well in 2009.

The average realized sales price for oil was $58.24 per barrel for the year ended December 31, 2009, a decrease of 41%, compared to $98.59 per barrel for 2008. The average realized sales price for NGLs was $27.26 for the year ended December 31, 2009, a decrease of 46%, compared to $50.24 per barrel for 2008. The average realized sales price for natural gas was $3.47 per Mcf for the year ended December 31, 2009, a decrease of 56%, compared to $7.87 per Mcf for 2008.

Realized and Unrealized Gain (Loss) from Derivatives. For the year ended December 31, 2009, our loss from derivatives was $11.3 million compared to a gain of $22.8 million for the year ended December 31, 2008. Our gains and losses for these periods were the net result of recording actual contract settlements, the premiums paid for our derivative contracts, and unrealized gains and losses attributable to mark-to-market values of our derivative contracts at the end of the periods.

	Year ended December 31, 2009	2008
	(in thousands)	
Contract settlements and premium costs:		
Oil	$ 5,626	$ (10,497)
Natural gas	13,629	25
Realized gains (losses)	19,255	(10,472)
Mark-to-market gains (losses):		
Oil	(23,724)	26,590
Natural gas	(6,837)	6,667
Unrealized gains (losses)	(30,561)	33,257
Realized and unrealized gains (losses)	$ (11,306)	$ 22,785

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $5.3 million for the year ended December 31, 2009, compared to $10.5 million for the year ended December 31, 2008, due primarily to lower commodity prices during the 2009 period. Production taxes vary by state. Most are based on realized prices at the wellhead, while Louisiana production tax is based on volumes for natural gas and value for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 5.4% for the year ended December 31, 2009, compared to 5.7% for the year ended December 31, 2008.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $37.5 million for the year ended December 31, 2009, a decrease of $0.5 million, or 2%, from the $38.0 million for the year ended December 31, 2008. For the year ended December 31, 2009, our oil and natural gas production expense was $14.73 per Boe compared to $14.89 per Boe for the year ended December 31, 2008, essentially flat. As a percentage of oil and natural gas sales, oil and natural gas production expense was 38% for the year ended December 31, 2009, as compared to 21% for the year ended December 31, 2008. The increase is due to declining commodity prices in the 2009 period.

Depreciation and Amortization Expense. Our depreciation and amortization expense decreased $14.9 million, or 32%, for the year ended December 31, 2009, compared to the year ended December 31, 2008. The decrease was a result of a lower amortization rate per Boe. On an equivalent basis, our amortization of the full-cost pool of $30.7 million was $12.06 per Boe for the year ended December 31, 2009, a decrease per Boe of 33%

compared to $45.7 million, or $17.89 per Boe for the year ended December 31, 2008. This rate decrease per Boe resulted from lower capitalized costs subsequent to the asset impairment writedowns in the fourth quarter of 2008 and the first quarter of 2009.

Accretion Expense. Topic 410 of the Codification includes, among other things, the accounting for asset retirement obligations. Accretion expense is a function of changes in the discounted liability from period to period. We recorded $2.0 million for the year ended December 31, 2009, compared to $2.2 million for the year ended December 31, 2008.

Impairment Charge. We incurred a $47.6 million impairment on the carrying value of our oil and gas properties for the year ended December 31, 2009 as compared to $269.4 million for the year ended December 31, 2008. We also incurred a $0.5 million impairment on the carrying value of our inventory in 2008. The impairment of our oil and gas properties was primarily due to a reduction in the estimated present value of future net revenues from our proved oil and gas reserves resulting from a significant decline in commodity prices during the fourth quarter of 2008.

Share-Based Compensation. From time to time, our board of directors grants restricted stock awards under our 2006 Long-Term Incentive Plan. Each of these grants vests in equal increments over the vesting period provided for the particular award. All currently unvested awards provide for vesting periods of from one to five years. The share-based compensation expense related to these grants is calculated using the closing price per share on each of the grant dates and the total share-based compensation on all these grants will be recognized over their respective vesting periods. For the year ended December 31, 2009, we recorded a total of $2.2 million share-based compensation expense compared to $2.6 million for the year ended December 31, 2008. The decrease in share-based compensation expense was a result of the accelerated vesting in the 2008 period of restricted stock grants to John Cox, our senior vice president, who passed away in March 2008.

General and Administrative Expense. For the year ended December 31, 2009, our general and administrative expense was $16.7 million, compared to $20.3 million for the year ended December 31, 2008, a decrease of $3.6 million, or 18%. The decrease is primarily due to decreased professional fees and lower officer and employee bonuses in 2009.

Interest Expense. We recorded interest expense of $18.6 million for the year ended December 31, 2009, compared to $24.2 million incurred during the previous year. The decrease in interest expense was due to lower debt balances for the 2009 period and lower effective interest rates in the first half of 2009 compared to 2008, partially offset by higher interest rates during the second half of 2009 due to the Second Amendment to our credit facility executed June 26, 2009. Our debt was lower during 2009 because in the second quarter of 2008, we used $86.6 million in realized net proceeds from the exercise of 17,617,331 warrants in May 2008 to pay down the term facility, and $9.4 million in cash to pay down the revolver. Our blended interest rate was 7.6% during 2009 compared to 9.7% in the 2008 period. As a result of this paydown and lower interest rates for the period, our interest expense decreased by $5.6 million for the year ended December 31, 2009 compared to 2008.

Other Expense. Our other expense was $0.4 million in 2009 compared to $13.5 million in 2008. In 2008, we recorded a charge to other expense of $13.5 million for litigation expense related to a legal settlement. In September 2008, we entered into an agreement pursuant to which we agreed to pay $16.0 million in settlement of a pending class action lawsuit. We placed that amount in escrow in October 2008 in anticipation of a final court approved settlement in the second quarter of 2009. In conjunction with our May 8, 2006 acquisition of RAM Energy, the former stockholders of RAM Energy deposited in escrow 3,200,000 shares of their common stock to secure their potential indemnity obligations to us, including any loss we might sustain in this litigation or through an agreed settlement. At December 31, 2008, we recorded a contingent liability of $16.0 million for the settlement and a receivable of $2.8 million representing the market value of the escrow shares based on the closing price of $0.88 per share on December 31, 2008. The $13.5 million charge to other expense represents the difference between the settlement liability and the value of the escrowed shares. On March 5, 2009, the court

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approved the settlement and on April 6, 2009, the settlement became final. We recorded a $0.4 million charge to other expense in the first quarter of 2009 representing the adjustment to fair market value of the escrowed shares on the final settlement date of $0.74 per share.

Income Taxes. For the year ended December 31, 2009, we recorded an income tax benefit of $16.3 million on a pre-tax loss of $74.7 million. In 2009, we recorded an increase in valuation allowance of $9.5 million to reflect our estimate of reduced tax benefits expected to be realized from net deferred tax assets of the company. For the year ended December 31, 2008, we recorded an income tax benefit of $91.7 million on a pre-tax loss of $221.6 million. Included in the income tax benefit for 2008 is a $6.9 million decrease resulting from the reversal of an uncertain tax position and related accrued interest. The effective tax rate for the year ended December 31, 2009 was 21.9%. Excluding the reversal of the uncertain tax position, the effective tax rate was 38.3% for the year ended December 31, 2008. The lower effective tax rate in 2009 was a result of the increased valuation allowance, which caused a decrease in deferred tax benefit.

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

Oil and natural gas sales increased $100.8 million, or 123%, to $182.7 million for the year ended December 31, 2008 as compared to $81.9 million for the year ended December 31, 2007. This increase was driven by both volume increases which were 80% for the year ended December 31, 2008 as compared to 2007, and by commodity price increases, which were 24% for the year ended December 31, 2008 as compared to 2007. The production increase was the result of the recently acquired South Texas and Appalachia fields in the Ascent acquisition, a 48% increase in the Barnett Shale field, a 47% increase in our mature oil fields, and a 28% increase in our mature natural gas fields.

The following tables summarize our oil and natural gas production volumes (in thousands), average sale prices and comparisons for the years ended December 31, 2008 and 2007:

		Developing Fields		Mature Oil Fields*	Mature Natural Gas Fields	
	South Texas	**Barnett Shale**	**Appalachia**	**Various**	**Various**	**Total**
Year Ended December 31, 2008						
Aggregate Net Production						
Oil (MBbls)	49	7	1	977	153	1,187
NGLs (MBbls)	113	85		81	75	354
Natural Gas (MMcf)	2,587	576	62	1,046	1,811	6,082
MBoe	593	188	11	1,232	530	2,554
Year Ended December 31, 2007						
Aggregate Net Production						
Oil (MBbls)	3	4		706	61	774
NGLs (MBbls)	8	41		65	70	184
Natural Gas (MMcf)	199	490		405	1,691	2,785
MBoe	44	127		838	413	1,422
Change in MBoe	549	61	11	394	117	1,132
Percentage Change in MBoe	1247.7%	48.0%	0.0%	47.0%	28.3%	79.6%

* Includes Electra/Burkburnett, Allen/Fitts and Layton fields.

	Year ended December 31, 2008	2007	Increase
Average sale prices:			
Oil (per Bbl)	$ 98.59	$ 71.11	38.6%
NGL (per Bbl)	$ 50.24	$ 49.16	2.2%
Natural gas (per Mcf)	$ 7.87	$ 6.40	23.0%
Per Boe	$ 71.52	$ 57.60	24.2%

Production volumes increased 80% during the year ended December 31, 2008 primarily due to the Ascent acquisition in November 2007, and the 84.0 gross development and 6.0 gross exploratory wells drilled during the year ended December 31, 2008. Production from our developing fields of South Texas, Barnett Shale, and Appalachia (West Virginia) increased by 621 MBoe in the current year and accounted for 55% of our total production growth as compared with the year ended December 31, 2007. Drilling activity included 5.0 gross development wells in Starr and Wharton Counties of South Texas, 6.0 gross additional Barnett Shale development wells and 1.0 gross exploratory well, and 4.0 gross development and 4.0 gross exploratory wells in the developing field of Appalachia in West Virginia. Production from our mature oil fields of Electra/Burkburnett in North Texas and Allen/Fitts in Pontotoc County, Oklahoma increased by 394 MBoe over the prior year, which accounted for 35% of our total production growth as compared with 2007. Drilling activity included 42.0 gross development wells in Electra/Burkburnett and 8.0 gross development wells in Allen/Fitts.

The average realized sales price for oil was $98.59 per barrel for the year ended December 31, 2008, an increase of 39%, compared to $71.11 per barrel for 2007. The average realized sales price for NGLs was $50.24 for the year ended December 31, 2008, an increase of 2%, compared to $49.16 per barrel for 2007. The average realized sales price for natural gas was $7.87 per Mcf for the year ended December 31, 2008, an increase of 23%, compared to $6.40 per Mcf for 2007.

Realized and Unrealized Gain (Loss) from Derivatives. For the year ended December 31, 2008, our gain from derivatives was $22.8 million compared to a loss of $12.7 million for the year ended December 31, 2007. Our gains and losses for these periods were the net result of recording actual contract settlements, the premiums paid for our derivative contracts, and unrealized gains and losses attributable to mark-to-market values of our derivative contracts at the end of the periods.

	Year ended December 31, 2008	2007
	(in thousands)	
Contract settlements and premium costs:		
Oil	$ (10,497)	$ (3,362)
Natural gas	25	693
Realized losses	(10,472)	(2,669)
Mark-to-market gains (losses):		
Oil	26,590	(9,689)
Natural gas	6,667	(367)
Unrealized gains (losses)	33,257	(10,056)
Realized and unrealized gains (losses)	$ 22,785	$ (12,725)

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $10.5 million for the year ended December 31, 2008, compared to $4.9 million for the year ended December 31, 2007. Production taxes vary by state. Most are based on realized prices at the wellhead, while Louisiana production tax is based on volumes for natural gas and value for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 5.7% for the year ended December 31, 2008, compared to 6.0% for the year ended December 31, 2007.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $38.0 million for the year ended December 31, 2008, an increase of $16.4 million, or 76%, from the $21.6 million for the year ended December 31, 2007. The increase was due primarily to our acquisition of Ascent Energy in November 2007. For the year ended December 31, 2008, our oil and natural gas production expense was $14.89 per Boe compared to $15.18 per Boe for the year ended December 31, 2007, a decrease of 2%. As a percentage of oil and natural gas sales, oil and natural gas production expense was 21% for the year ended December 31, 2008, as compared to 26% for the year ended December 31, 2007.

Depreciation and Amortization Expense. Our depreciation and amortization expense increased $27.6 million, or 145%, for the year ended December 31, 2008, compared to the year ended December 31, 2007. The increase was a result of higher capitalized costs due to our acquisition of Ascent Energy in November 2007. On an equivalent basis, our amortization of the full-cost pool of $45.7 million was $17.89 per Boe for the year ended December 31, 2008, an increase per Boe of 39% compared to $18.3 million, or $12.86 per Boe for the year ended December 31, 2007. This rate increase per Boe resulted from our recording of the Ascent reserves at their acquisition cost in connection with the merger.

Accretion Expense. Topic 410 of the Codification includes, among other things, the accounting for asset retirement obligations. Accretion expense is a function of changes in the discounted liability from period-to-period. We recorded $2.2 million for the year ended December 31, 2008, compared to $0.7 million for the year ended December 31, 2007. The increase was due primarily to our acquisition of Ascent Energy in November 2007.

Impairment Charge. We incurred a $269.4 million impairment on the carrying value of our oil and gas properties during 2008. We also incurred a $0.5 million impairment on the carrying value of our inventory. The impairment of our oil and gas properties was primarily due to a reduction in the estimated present value of future net revenues from our proved oil and gas reserves resulting from a significant decline in commodity prices during the fourth quarter of 2008.

Share-Based Compensation. From time to time, our board of directors grants restricted stock awards under our 2006 Long-Term Incentive Plan. Each of these grants vests in equal increments over the vesting period provided for the particular award. All currently unvested awards provide for vesting periods of from one to five years. The share-based compensation on these grants was calculated using the closing price per share on each of the grant dates and the total share-based compensation on all these grants will be recognized over their respective vesting periods. For the year ended December 31, 2008, we recognized a total of $2.6 million share-based compensation compared to $1.0 million for the year ended December 31, 2007. The increase in share-based compensation expense was a result of additional stock grant issuances in connection with our acquisition of Ascent Energy, and the accelerated vesting of restricted stock grants to John Cox, our senior vice president who passed away in March 2008.

General and Administrative Expense. For the year ended December 31, 2008, our general and administrative expense was $20.3 million, compared to $11.9 million for the year ended December 31, 2007, an increase of $8.4 million, or 71%. The increase is primarily due to increased salary expense and an increased number of employees associated with our acquisition of Ascent Energy in November 2007, together with increased professional fees and expenses.

Interest Expense. Our interest expense increased by $3.4 million, to $24.2 million for the year ended December 31, 2008, compared to $20.8 million incurred for the previous year. This increase of 17% was due to higher outstanding indebtedness during the 2008 period compared to the 2007 period, offset partially by lower effective interest rates.

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Other Expense. We recorded a charge to other expense of $13.5 million for litigation expense related to a legal settlement. In September 2008, we entered into an agreement pursuant to which we agreed to pay $16.0 million in settlement of a pending class action lawsuit. We placed that amount in escrow in October 2008 in anticipation of a final court approved settlement in the second quarter of 2009. In conjunction with our May 8, 2006 acquisition of RAM Energy, the former stockholders of RAM Energy deposited in escrow 3,200,000 shares of their common stock to secure their potential indemnity obligations to us, including any loss we might sustain in this litigation or through an agreed settlement. These escrowed shares will remain in escrow until the settlement becomes final or the litigation is otherwise resolved. At December 31, 2008, we recorded a contingent liability of $16.0 million for the settlement and a receivable of $2.8 million representing the market value of the escrow shares based on the closing price of $0.88 per share on December 31, 2008. The $13.5 million charge to other expense represents the difference between the settlement liability and the value of the escrowed shares.

Income Taxes. For the year ended December 31, 2008, we recorded an income tax benefit of $91.7 million, on a pre-tax loss of $221.6 million. Included in this income tax benefit is a $6.9 million decrease resulting from the reversal of an uncertain tax position and related accrued interest. For the year ended December 31, 2007, our income tax benefit was $3.3 million, on a pre-tax loss of $9.1 million. We also reduced income tax by $4.6 million in the 2007 period to reverse a deferred tax position in our 2003 federal income tax return. Excluding the reversal of the uncertain tax position, the effective tax rate was 38.3% for the year ended December 31, 2008 and 36.3% for the year ended December 31, 2007.

Liquidity and Capital Resources

As of December 31, 2009, we had cash and cash equivalents of $0.1 million and $40.0 million of nominal availability under our revolving credit facility; however, because of the amount of our Modified EBITDA for the preceding four fiscal quarters, the financial covenants in our credit facility would have limited us to $25.3 million of additional borrowings as of December 31, 2009. We will be unable to borrow the full amount of our borrowing base until our Modified EBITDA for the preceding four fiscal quarters equals or exceeds $63.6 million. Management believes that borrowings currently available to us under our credit facilities and anticipated cash flows from operations will be sufficient to satisfy our currently expected capital expenditures, working capital, and debt service obligations through 2010. At December 31, 2009, we had $246.2 million of indebtedness outstanding, including $135.0 million under our revolving credit facility, $111.0 million under our term loan facility and $0.2 million in other indebtedness. As of December 31, 2009, we had an accumulated deficit of $217.3 million and a working capital deficit of $14.4 million.

Credit Facility. In November 2007, in conjunction with the Ascent acquisition, we entered into a new $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. The new facility, which replaced our previous $300.0 million facility, includes a $250.0 million revolving credit facility, a $200.0 million term loan facility, and an additional $50.0 million available under the term loan as requested by us and approved by the lenders. The entire amount of the $200.0 million term loan was advanced at closing. The borrowing base under the revolving credit facility at the closing was $175.0 million, a portion of which was advanced at the closing of the Ascent acquisition. Borrowings under the new facility were used to refinance RAM Energy s existing indebtedness, fund the cash requirements in connection with the closing of the Ascent acquisition, and for working capital and other general corporate purposes. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the four-year term of the revolver, and initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The term loan portion of our credit facility initially provided for payments of interest only during its five-year term, with the initial interest rate being LIBOR plus 7.5%. The $175.0 million borrowing base was reaffirmed in September 2009 based on the value of our proved reserves at June 30, 2009.

Advances under our credit facility are secured by liens on substantially all of our properties and assets. The credit facility contains representations, warranties and covenants customary in transactions of this nature, including financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to total indebtedness.

On June 26, 2009, we renegotiated certain terms of our credit facility to provide us greater flexibility in complying with certain of the financial covenants under the loan agreement. In exchange for the added flexibility afforded by these changes to the credit facility, we agreed to increase the base cash interest rate on both the revolving credit facility and the term loan credit facility by 1% per annum, establish a LIBOR floor of 1.5% and pay an additional 2.75% per annum of non-cash, payment-in-kind, or PIK, interest on the term portion of the facility. Accrued PIK interest is added to the principal balance of the term loan on a monthly basis and will be paid at maturity.

In May of 2008, we used $86.6 million in realized net proceeds from the exercise of 17,617,331 warrants to pay down the term facility to $113.4 million. In 2009 we used $4.0 million in proceeds from asset sales to pay down the term facility. PIK interest of $1.6 million was added to the term facility in 2009, bringing the balance to $111.0 million at December 31, 2009.

Notwithstanding the recent amendments to our loan agreement, our ability to comply with the financial covenants in our credit facility may be affected by events beyond our control and, as a result, in future periods we may be unable to 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 corporate activities. A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit facility. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit facility. The accelerated debt would become immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. At December 31, 2009, we were in compliance with all of the financial covenants under our credit facility.

We are required to maintain commodity hedges with respect to not less than 50%, but not more than 85%, of our projected monthly production volumes on a rolling 30-month basis, until the leverage ratio is less than or equal to 2.0 to 1.0. At December 31, 2009, our commodity hedging represented approximately 51% of our projected production volumes through June 30, 2012.

Senior Notes. In February 1998, RAM Energy completed the sale of $115.0 million of 11.5% Senior Notes due 2008 in a public offering of which $28.4 million remained outstanding at December 31, 2007. These notes were retired at maturity on February 15, 2008 using proceeds from our revolving credit facility.

Cash Flow From Operating Activities. Our cash flow from operating activities is comprised of three main items: net income (loss), adjustments to reconcile net income to cash provided (used) before changes in working capital, and changes in working capital. For the year ended December 31, 2009, our net loss was $58.4 million, as compared to a net loss of $130.0 million for the year ended December 31, 2008. Adjustments (primarily non-cash items such as asset impairment charge, depreciation and amortization, unrealized gain or loss on derivatives, deferred income taxes and legal contingency expense) were $102.4 million for the year ended December 31, 2009 compared to $211.5 million for the year of 2008, a decrease of $109.1 million. Asset impairment charge, depreciation and amortization and legal contingency expense offset by change in unrealized (gains) losses and deferred income taxes caused most of this decrease. Working capital changes for the year ended December 31, 2009 were a negative $11.7 million compared with negative changes of $7.1 million for the year ended December 31, 2008. For the year ended December 31, 2009, in total, net cash provided by operating activities was $32.4 million compared to $74.5 million of net cash provided by operations for the previous year.

Cash Flow From Investing Activities. For the year ended December 31, 2009 net cash used in our investing activities consisted of $30.5 million in payments for oil and gas properties and other equipment, offset by $6.1 million in proceeds from sales of oil and natural gas properties and $0.4 million from the sale of other property and equipment. For the year ended December 31, 2008, net cash used in our investing activities was $82.6 million; 71% higher than the current year. The change is primarily due to a reduction in capital expenditures in the 2009 period.

Cash Flow From Financing Activities. For the year ended December 31, 2009, net cash used in our financing activities was $8.5 million, compared to net cash provided of $1.4 million for the year ended December 31, 2008. The cash used in 2009 included $6.2 million in net payments on long-term debt and $2.3 million for deferred loan costs. The cash provided in 2008 included $86.6 million in proceeds received from the exercise of warrants, which we used to pay down our term loan facility, and other net payments on our revolving credit facility of $1.4 million.

Capital Commitments

During 2009, we had capital expenditures of $29.9 million relating to our oil and natural gas operations, of which $28.3 million was allocated to drilling new development wells and recompletion operations in existing wells, $0.3 million was for exploration costs, and $1.3 million was for acquisition costs.

We have budgeted $50.0 million for non-acquisition capital expenditures in 2010 related to:

- geological, geophysical and seismic costs ($6.0 million);
- developmental drilling and recompletions ($38.0 million); and
- exploratory drilling, including leasehold acquisitions ($6.0 million).

In our 2010 non-acquisition capital budget, we have allocated $22.0 million for drilling on our South Texas properties, $3.0 million for our North Texas Barnett Shale, $9.0 million for continued development of our Electra/Burkburnett area, $2.0 million for reworking and production enhancement operations in our other mature fields, and $2.0 million to our Pontotoc properties in Oklahoma.

The amount and timing of our capital expenditures for calendar year 2010 may vary depending on a number of factors, including prevailing market prices for oil and natural gas, the favorable or unfavorable results of operations actually conducted, projects proposed by third party operators on jointly owned acreage, development by third party operators on adjoining properties, rig and service company availability, and other influences that we cannot predict.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that cash flows from operations and the availability under our revolving credit facility will be sufficient to satisfy our budgeted non-acquisition capital expenditures, working capital and debt service obligations for 2010. The actual amount and timing of our future capital requirements may differ materially from our estimates as a result of, among other things, changes in product pricing and regulatory, technological and competitive developments. Sources of additional financing available to us may include commercial bank borrowings, vendor financing and the sale of equity or debt securities. We cannot provide any assurance that any such financing will be available on acceptable terms or at all.

The credit markets are undergoing significant volatility. Many financial institutions have liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to the current credit market crisis includes our revolving credit facility, counterparty risks related to our trade credit and risks related to our cash investments.

Our revolving credit facility matures in November 2011. Our term loan facility matures in November 2012. Should the current tightness in the credit markets continue, future extensions of our credit facility may contain terms that are less favorable than those of our current credit facility.

Current market conditions also elevate the concern over our cash deposits, which totaled approximately $0.1 million at December 31, 2009 but fluctuate throughout the year, and counterparty risks related to our trade credit. Our cash accounts and deposits with any financial institution that exceed the amount insured by the

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Federal Deposit Insurance Corporation are at risk in the event one of these financial institutions fail. We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of these parties are not as creditworthy as we are and may experience liquidity problems. Non performance by a trade creditor could result in losses.

The table below sets forth our contractual cash obligations as of December 31, 2009:

	Total	2010	2011-2012 (in thousands)	2013-2014	and after
Contractual Cash Obligations					
Long-term debt	$ 246,167	$ 126	$ 246,041	$	$
Operating leases	4,776	1,253	2,406	1,117	
Total contractual cash obligations	$ 250,943	$ 1,379	$ 248,447	$ 1,117	$

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The carrying amounts reported in our consolidated balance sheets for cash and cash equivalents, trade receivables and payables, installment notes and variable rate long-term debt approximate their fair values.

Interest Rate Sensitivity

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents and the interest rate paid on our borrowings. We have not used interest rate derivative instruments to manage our exposure to interest rate changes.

Our long-term debt as of December 31, 2009 is denominated in U.S. dollars. Our debt has been issued at variable rates, and as such, interest expense would be impacted by interest rate shifts. The impact of a 100-basis point increase in LIBOR interest rates above our current floor of 1.5% would result in an increase in interest expense of $2.5 million annually. A 100-basis point decrease would have no effect on interest expense until the market rate of LIBOR is above our current floor of 1.5%.

Commodity Price Risk

Our revenue, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell most of our oil and natural gas production under market price contracts.

To reduce exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow, and as required by our lenders, we utilize various derivative strategies to manage the price received for a portion of our future oil and natural gas production. We have not established derivatives in excess of our expected production.

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Our derivative positions at December 31, 2009, consisting of put/call collars and put options, also called bare floors as they provide a floor price without a corresponding ceiling, are shown in the following table:

	Crude Oil (Bbls)					Natural Gas (Mmbtu)				
	Floors		Ceilings			Floors		Ceilings		
	Per Day[1]	Price	Per Day	Price	Months Covered	Per Day[1]	Price	Per Day	Price	Months Covered
Collars										
2010	1,503	$ 53.74	1,503	$ 80.57	January - December	5,288	$ 5.00	5,288	$ 9.23	January - June, November - December
2011		$		$		4,959	$ 5.00	4,959	$ 9.60	January - June

	Bare Floors			Bare Floors		
	Per Day[1]	Price	Months Covered	Per Day[1]	Price	Months Covered
Year						
2010	1,121	$ 64.84	January - March, July - December	5,452	$ 4.46	April - December
2011	744	$ 60.00	January - June		$	

(1) Per day amounts are calculated based on a 365-day year.

Based on December 31, 2009 NYMEX forward curves of natural gas and crude oil futures prices, adjusted for volatility by 40 basis points, we would expect to pay future cash payments of $4.8 million under our natural gas and crude oil derivative arrangements as they mature. If future prices of natural gas and crude oil were to decline by 10%, we would expect to pay future cash payments under our natural gas and crude oil derivative arrangements of $0.6 million, and if future prices were to increase by 10%, we would pay future cash payments of $9.1 million.

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Item 8. ***Financial Statements and Supplementary Data***

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

RAM Energy Resources, Inc.

We have audited the accompanying consolidated balance sheets of RAM Energy Resources, Inc. (a Delaware corporation) and subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity (deficit) and cash flows for each of the three years in the period ended December 31, 2009. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated 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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes 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 presently fairly, in all material respects, the consolidated financial position of RAM Energy Resources, Inc. and subsidiaries at December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note A to the consolidated financial statements, in 2009, the Company adopted SEC Release 33-8995 and the amendments to ASC Topic 932, Extractive Industries Oil and Gas, resulting from ASU 2010-03 (collectively, the Modernization Rules).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of RAM Energy Resources, Inc. and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2010 expressed an unqualified opinion on the effective operation of internal control over financial reporting.

/s/ UHY LLP

Houston, Texas

March 10, 2010

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RAM Energy Resources, Inc.

Consolidated Balance Sheets

(in thousands, except share and per share amounts)

	As of December 31, 2009	As of December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 129	$ 164
Cash, restricted		16,000
Accounts receivable:		
Oil and natural gas sales, net of allowance of $50 ($50 at December 31, 2008)	12,585	8,702
Joint interest operations, net of allowance of $641 ($515 at December 31, 2008)	1,303	818
Other, net of allowance of $48 ($35 at December 31, 2008)	193	4,045
Derivative assets		21,006
Prepaid expenses	1,970	2,330
Deferred tax asset	3,531	
Inventory	3,900	4,116
Other current contingencies		2,816
Other current assets	27	25
Total current assets	23,638	60,022
PROPERTIES AND EQUIPMENT, AT COST:		
Proved oil and natural gas properties and equipment, using full cost accounting	702,502	683,341
Other property and equipment	9,337	9,460
	711,839	692,801
Less accumulated depreciation, amortization and impairment	(462,541)	(383,476)
Total properties and equipment	249,298	309,325
OTHER ASSETS:		
Deferred tax asset	31,573	24,018
Derivative assets		4,531
Deferred loan costs, net of accumulated amortization of $2,924 ($1,282 at December 31, 2008)	4,697	4,015
Other	1,956	2,053
Total assets	$ 311,162	$ 403,964
LIABILITIES AND STOCKHOLDERS EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 15,697	$ 26,370
Oil and natural gas proceeds due others	10,113	7,218
Other	636	982
Accrued liabilities:		
Compensation	2,664	2,893
Interest	2,933	865
Franchise taxes		1,300
Income taxes	655	399
Contingencies		16,000
Other	10	
Deferred income taxes		5,779
Derivative liabilities	4,471	
Asset retirement obligations	711	1,093
Long-term debt due within one year	126	160
Total current liabilities	38,016	63,059

OIL & NATURAL GAS PROCEEDS DUE OTHERS		2,523
DERIVATIVE LIABILITIES	358	
LONG-TERM DEBT	246,041	250,536
ASSET RETIREMENT OBLIGATIONS	26,363	29,106
OTHER LONG-TERM LIABILITIES	10	
COMMITMENTS AND CONTINGENCIES	900	900
STOCKHOLDERS EQUITY (DEFICIT):		
Common stock, $0.0001 par value, 100,000,000 shares authorized, 80,748,674 and 79,423,574 shares issued, 76,951,883 and 78,532,134 shares outstanding at December 31, 2009 and 2008, respectively	8	8
Additional paid-in capital	222,979	220,800
Treasury stock 3,796,791 shares (891,440 shares at December 31,2008) at cost	(6,189)	(4,027)
Accumulated deficit	(217,324)	(158,941)
Stockholders equity (deficit)	(526)	57,840
Total liabilities and stockholders equity (deficit)	$ 311,162	$ 403,964

The accompanying notes are an integral part of these consolidated financial statements.

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RAM Energy Resources, Inc.

Consolidated Statements of Operations

(in thousands, except share and per share amounts)

	Years ended December 31, 2009	2008	2007
REVENUES AND OTHER OPERATING INCOME:			
Oil and natural gas sales			
Oil	$ 66,281	$ 117,036	$ 55,000
Natural gas	20,818	47,884	17,830
NGLs	11,068	17,770	9,047
Total oil and natural gas sales	98,167	182,690	81,877
Realized gains (losses) on derivatives	19,255	(10,472)	(2,669)
Unrealized gains (losses) on derivatives	(30,561)	33,257	(10,056)
Other	217	382	488
Total revenues and other operating income	87,078	205,857	69,640
OPERATING EXPENSES:			
Oil and natural gas production taxes	5,320	10,480	4,869
Oil and natural gas production expenses	37,455	38,030	21,574
Depreciation and amortization	31,650	46,512	18,948
Accretion expense	1,976	2,207	704
Impairment	47,613	269,886	
Share-based compensation	2,179	2,563	989
General and administrative, overhead and other expenses, net of operator s overhead fees	16,667	20,305	11,891
Total operating expenses	142,860	389,983	58,975
Operating income (loss)	(55,782)	(184,126)	10,665
OTHER INCOME (EXPENSE):			
Interest expense	(18,590)	(24,182)	(20,757)
Interest income	82	208	1,047
Other expense	(440)	(13,536)	(57)
LOSS BEFORE INCOME TAXES	(74,730)	(221,636)	(9,102)
INCOME TAX BENEFIT	(16,347)	(91,683)	(7,852)
Net loss	$ (58,383)	$ (129,953)	$ (1,250)
BASIC LOSS PER SHARE	$ (0.75)	$ (1.80)	$ (0.03)
BASIC WEIGHTED AVERAGE SHARES OUTSTANDING	77,601,057	72,234,750	42,087,617
DILUTED LOSS PER SHARE	$ (0.75)	$ (1.80)	$ (0.03)
DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING	77,601,057	72,234,750	42,087,617

The accompanying notes are an integral part of these consolidated financial statements.

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RAM Energy Resources, Inc.

Consolidated Statements of Stockholders Equity (Deficit)

Years ended December 31, 2009, 2008, and 2007

(In thousands, except share amounts)

	Common Stock		Additional	Treasury Stock			Stockholders
			Paid-In			Accumulated	Equity
	Shares	Amount	Capital	Shares	Amount	Deficit	(Deficit)
BALANCE, January 1, 2007	34,276,805	$ 3	$ 2,308	837,275	$ (3,768)	$ (26,438)	$ (27,895)
Long term incentive plan grants	300,262						
Long term incentive plan forfeitures	(18,775)						
Adoption of FIN 48 (uncertain tax positions)						(1,300)	(1,300)
Net loss						(1,250)	(1,250)
Issuance of shares for cash, net of costs	7,500,000	1	27,365				27,366
Issuance of shares relating to merger with Ascent Energy, Inc.	18,783,344	2	96,908				96,910
Issuance of warrants relating to merger with Ascent Energy, Inc.			4,049				4,049
Warrants exercised	1,200		6				6
Repurchase of stock				52,391	(177)		(177)
Share-based compensation			989				989
BALANCE, December 31, 2007	60,842,836	6	131,625	889,666	(3,945)	(28,988)	98,698
Long term incentive plan grants	1,104,800						
Long term incentive plan forfeitures	(141,393)						
Net loss						(129,953)	(129,953)
Warrants exercised	17,617,331	2	86,612				86,614
Repurchase of stock				1,774	(82)		(82)
Share-based compensation			2,563				2,563
BALANCE, December 31, 2008	79,423,574	8	220,800	891,440	(4,027)	(158,941)	57,840
Long term incentive plan grants	1,343,000						
Long term incentive plan forfeitures	(17,900)						
Net loss						(58,383)	(58,383)
Repurchase of stock				21,541	(28)		(28)
Receipt of common stock for settlement of contingent receivable				2,883,810	(2,134)		(2,134)
Share-based compensation			2,179				2,179
BALANCE, December 31, 2009	80,748,674	$ 8	$ 222,979	3,796,791	$ (6,189)	$ (217,324)	$ (526)

The accompanying notes are an integral part of these consolidated financial statements.

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RAM Energy Resources, Inc.

Consolidated Statements of Cash Flows

(in thousands)

	Years ended December 31,		
	2009	**2008**	**2007**
OPERATING ACTIVITIES:			
Net loss	$ (58,383)	$ (129,953)	$ (1,250)
Adjustments to reconcile net loss to net cash provided by operating activities-			
Depreciation and amortization	31,650	46,512	18,948
Amortization of deferred loan costs and Senior Notes discount	1,642	1,197	945
Write off of loan fees due to debt refinancing			2,435
Non-cash interest	1,605		
Accretion expense	1,976	2,207	704
Impairment	47,613	269,886	
Unrealized (gain) loss on derivatives, net of premium amortization	32,147	(31,762)	10,635
Deferred income tax benefit	(16,865)	(92,595)	(9,165)
Other expense	448	13,184	
Share-based compensation	2,179	2,563	989
Loss (gain) on disposal of other property, equipment and subsidiary	35	180	(61)
Undistributed losses on investment		165	57
Changes in operating assets and liabilities, net of acquisitions			
Accounts receivable	(650)	4,168	(2,775)
Prepaid expenses, inventory and other assets	905	(4,283)	(117)
Derivative premiums	(1,781)	(2,288)	(1,600)
Accounts payable and proceeds due others	(10,641)	14,606	(3,626)
Accrued liabilities and other	(15,387)	(3,124)	(265)
Restricted cash	16,000	(16,000)	
Income taxes payable	256	231	1,313
Asset retirement obligations	(377)	(440)	(125)
Total adjustments	90,755	204,407	18,292
Net cash provided by operating activities	32,372	74,454	17,042
INVESTING ACTIVITIES:			
Payments for oil and natural gas properties and equipment	(29,871)	(84,723)	(40,101)
Proceeds from sales of oil and natural gas properties	6,120	2,950	170
Payments for other property and equipment	(604)	(1,275)	(1,394)
Proceeds from sales of other property and equipment	434	23	71
Proceeds from sale of subsidiary, net of cash		308	
Acquisition of Ascent, net of cash acquired		35	(199,726)
Other investments		114	(212)
Net cash used in investing activities	(23,921)	(82,568)	(241,192)
FINANCING ACTIVITIES:			
Payments on long-term debt	(36,156)	(175,306)	(921)
Proceeds from borrowings on long-term debt	30,022	90,253	199,508
Payments for deferred loan costs	(2,324)	(74)	(1,480)
Stock repurchased	(28)	(82)	(177)
Common stock offering, net of direct costs			27,366
Warrants exercised		86,614	6
Net cash provided by (used in) financing activities	(8,486)	1,405	224,302
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(35)	(6,709)	152
CASH AND CASH EQUIVALENTS, beginning of year	164	6,873	6,721

CASH AND CASH EQUIVALENTS, end of year	$ 129	$ 164	$ 6,873

The accompanying notes are an integral part of these consolidated financial statements.

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RAM Energy Resources, Inc.

Consolidated Statements of Cash Flows (continued)

(in thousands)

	Years ended December 31,		
	2009	**2008**	**2007**
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for income taxes	$ 303	$ 682	$ 18
Cash paid for interest	$ 13,428	$ 25,813	$ 16,936
DISCLOSURE OF NON CASH INVESTING AND FINANCING ACTIVITIES:			
Payment-in-kind interest	$ 1,605	$	$ 481
Loan fees added to principal balance of credit facility	$	$	$ 4,400
Issuance of stock and warrants for Ascent merger	$	$	$ 101,065
Asset retirement obligations	$ (4,724)	$ 787	$ 16,140
Receipt of common stock for settlement of contingent receivable	$ 2,134	$	$

The accompanying notes are an integral part of these consolidated financial statements.

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RAM Energy Resources, Inc.

Notes to consolidated financial statements

December 31, 2009 and 2008

A SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, ORGANIZATION AND BASIS OF PRESENTATION

1. *Nature of Operations and Organization*

On May 8, 2006, Tremisis Energy Acquisition Corporation, or Tremisis, acquired RAM Energy, Inc., or RAM Energy, through the merger of a subsidiary of Tremisis into RAM Energy. The merger was accomplished pursuant to the terms of an Agreement and Plan of Merger dated October 20, 2005, as amended, among Tremisis, its subsidiary, RAM Energy and the stockholders of RAM Energy. Upon completion of the merger, RAM Energy became a wholly-owned subsidiary of Tremisis and Tremisis changed its name to RAM Energy Resources, Inc. (the Company).

Tremisis was formed in February 2004 to effect a merger, capital stock exchange, asset acquisition or other similar business combination with an unidentified operating business in either the energy or the environmental industry. Prior to the consummation of the merger, Tremisis did not engage in an active trade or business. Prior to the merger, RAM Energy was a privately held, independent oil and natural gas company engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties and the production of oil and natural gas.

The merger was accounted for as a reverse acquisition. Because Tremisis had no active business operations prior to consummation of the merger, the merger has been accounted for as a recapitalization of RAM Energy and RAM Energy has been treated as the acquirer and continuing reporting entity for accounting purposes. The assets and liabilities of Tremisis have been stated at historical cost, and added to those of RAM Energy.

On November 29, 2007, the Company acquired Ascent Energy Inc., an acquisition that significantly increased the size of the Company. See Note B.

The Company operates exclusively in the upstream segment of the oil and gas industry with activities including the drilling, completion, and operation of oil and gas wells. The Company conducts the majority of its operations in the states of Texas, Louisiana and Oklahoma.

2. *Basis of Presentation*

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated.

3. *Properties and Equipment*

The Company follows the full cost method of accounting for oil and natural gas operations. Under this method all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of oil and natural gas reserves are capitalized. No gains or losses are recognized upon the sale or other disposition of oil and natural gas properties except in transactions that would significantly alter the relationship between capitalized costs and proved reserves. The costs of unevaluated oil and natural gas properties are excluded from the amortizable base until the time that either proven reserves are found or it has been determined that such properties are impaired. As properties become evaluated, the related costs transfer to proved oil and natural gas properties using full cost accounting. All capitalized costs were included in the amortization base as of December 31, 2009 and 2008.

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Under the full cost method the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed the estimated after-tax future net revenues from proved oil and natural gas properties, discounted at 10% (the Ceiling Limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, and certain production-related and ad valorem taxes are deducted. In calculating future net revenues, prices and costs are held constant indefinitely, except for changes that are fixed and determinable by existing contracts. The net book value is compared to the Ceiling Limitation on a quarterly and yearly basis. The excess, if any, of the net book value above the Ceiling Limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. At March 31, 2009, the net book value of the Company s oil and natural gas properties exceeded the Ceiling Limitation resulting in a reduction in the carrying value of the Company s oil and natural gas properties of $47.6 million. The after-tax effect of this reduction was $30.3 million. At December 31, 2009, the net book value of the Company s oil and natural gas properties did not exceed the Ceiling Limitation. At December 31, 2008, the net book value of the Company s oil and natural gas properties exceeded the Ceiling Limitation resulting in a reduction in the carrying value of the Company s oil and natural gas properties by $269.4 million. The after-tax effect of this reduction in 2008 was $171.6 million.

Additionally, the Company assessed its materials and supplies inventory at December 31, 2008 and determined the book value of inventory exceeded the market value of the materials and supplies inventory. The assessment resulted in an impairment of $0.5 million for the year ended December 31, 2008.

The Company has capitalized internal costs of approximately $3.2 million, $5.0 million and $2.9 million for the years ended December 31, 2009, 2008, and 2007, respectively. Such capitalized costs include salaries and related benefits of individuals directly involved in the Company s acquisition, exploration and development activities based on the percentage of their time devoted to such activities.

Other property and equipment consists principally of furniture and equipment and leasehold improvements. Other property and equipment and related accumulated depreciation and amortization are relieved upon retirement or sale and the gain or loss is included in operations. Renewals and replacements that extend the useful life of property and equipment are treated as capital additions. Accumulated depreciation of other property and equipment at December 31, 2009 and 2008 is approximately $5.8 million and $5.0 million, respectively.

In accordance with authoritative guidance on accounting for the impairment or disposal of long-lived assets, as set forth in Topic 360 of the Accounting Standards Codification (the Codification) implemented by the Financial Accounting Standards Board (the FASB) , the Company assesses the recoverability of the carrying value of its non-oil and gas long-lived assets when events occur that indicate an impairment in value may exist. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If this occurs, an impairment loss is recognized for the amount by which the carrying amount of the assets exceeds the estimated fair value of the asset.

4. *Depreciation and Amortization*

All capitalized costs of oil and natural gas properties and equipment, including the estimated future costs to develop proved reserves, are amortized using the unit-of-production method based on total proved reserves. Depreciation of other equipment is computed on the straight-line method over the estimated useful lives of the assets, which range from three to twenty years. Amortization of leasehold improvements is computed based on the straight-line method over the term of the associated lease or estimated useful life, whichever is shorter.

5. *Natural Gas Sales and Gas Imbalances*

The Company follows the entitlement method of accounting for natural gas sales, recognizing as revenues only its net interest share of all production sold. Any amount attributable to the sale of production in excess of or less than the Company s net interest is recorded as a gas balancing asset or liability. At December 31, 2009 and 2008, the Company s gas imbalances were immaterial.

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6. *Cash Equivalents*

All highly liquid unrestricted investments with a maturity of three months or less when purchased are considered to be cash equivalents.

7. *Credit and Market Risk*

The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these operations are generally unsecured. In 2009, 2008, and 2007 approximately 61%, 53% and 50%, respectively, of total revenues were to one customer. The Company provides an allowance for doubtful accounts for certain purchasers and certain joint interest owners receivable balances when the Company believes the receivable balance may not be collected. Accounts receivable are presented net of the related allowance for doubtful accounts.

In 2009 and 2008 the Company had cash deposits in certain banks that at times exceeded the maximum insured by the Federal Deposit Insurance Corporation. The Company monitors the financial condition of the banks and has experienced no losses on these accounts.

8. *Deferred Loan Costs*

Deferred loan costs are stated at cost net of amortization computed using the straight-line method over the term of the related loan agreement, which approximates the interest method.

The estimated future amortization expense is as follows (in thousands):

Year ending December 31,	
2010	$2,088
2011	$1,972
2012	$ 637

9. *General and Administrative Expense*

The Company receives fees for the operation of jointly owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $0.6 million, $0.5 million and $0.2 million for the years ended December 31, 2009, 2008, and 2007, respectively.

10. *Use of Estimates*

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas reserves, amortization relating to oil and natural gas properties, asset retirement obligations, contingent litigation settlements, derivative instrument valuations and income taxes. The Company evaluates its estimates and assumptions on a regular basis. Estimates are based on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates used in preparation of our financial statements. In addition, alternatives can exist among various accounting methods. In such cases, the choice of accounting method can have a significant impact on reported amounts.

11. ***Oil and Natural Gas Reserves Estimates***

Independent petroleum and geological engineers prepare estimates of the Company s oil and natural gas reserves. Proved reserves, estimated future net revenues and the present value of our reserves are estimated based upon a combination of historical data and estimates of future activity. Consistent with SEC requirements, we have based our estimate of proved reserves on spot prices on the date of the estimate for periods prior to December 31, 2009. However, in accordance with the Securities and Exchange Commission s (SEC) Release No. 33-8995, Modernization of Oil and Gas Reporting, and Topic 932 of the Codification, effective December 31, 2009, the Company calculated its estimate of proved reserves using a twelve month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each period within the twelve-month period prior to the end of the reporting period. The reserve estimates are used in the assessment of the Company s Ceiling Limitation and in calculating depletion, depreciation and amortization. Significant assumptions are required in the valuation of proved oil and natural gas reserves which, as described herein, may affect the amount at which oil and natural gas properties are recorded. Actual results could differ materially from these estimates.

12. ***Fair Value of Financial Instruments***

Cash and cash equivalents, trade receivables and payables, and installment notes: The carrying amounts reported on the consolidated balance sheets approximate fair value due to the short-term nature of these instruments.

Credit facility: The carrying amount reported on the consolidated balance sheets approximates fair value because this debt instrument carries a variable interest rate based on market interest rates.

Derivative contracts: The carrying amount reported on the consolidated balance sheets is the estimated fair value of the Company s derivative instruments. See Notes I and J.

13. ***Reclassifications***

Certain reclassifications of previously reported amounts for 2008 and 2007 have been made to conform to the 2009 presentation. These reclassifications had no effect on net income or loss or cash flows from operating, investing or financing activities.

14. ***Derivatives***

The Company recognizes all derivative instruments as either assets or liabilities in the balance sheet at fair value in accordance with authoritative guidance as set forth in Topic 815 of the Codification.

The Company entered into numerous derivative contracts to reduce the impact of oil and natural gas price fluctuations and as required by the terms of its credit facility (see Notes C and J). The Company did not designate these transactions as hedges. Accordingly, all gains and losses on the derivative instruments during 2009, 2008 and 2007 have been recorded in the statements of operations.

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15. ***Loss per Common Share***

Basic loss per share is computed by dividing net loss by the weighted average number of common shares outstanding for the period. Diluted loss per share reflects the potential dilution that could occur if dilutive stock warrants were exercised, calculated using the treasury stock method. A reconciliation of net loss and weighted average shares used in computing basic and diluted net loss per share is as follows for the years ended December 31 (in thousands, except per share amounts):

	2009	2008	2007
Net loss	$ (58,383)	$ (129,953)	$ (1,250)
Weighted average shares basic	77,601,057	72,234,750	42,087,617
Dilutive effect of warrants			
Weighted average shares dilutive	77,601,057	72,234,750	42,087,617
Basic loss per share	$ (0.75)	$ (1.80)	$ (0.03)
Diluted loss per share	$ (0.75)	$ (1.80)	$ (0.03)

16. ***Asset Retirement Obligations***

Authoritative guidance, set forth in Topic 410 of the Codification, addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The authoritative guidance requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. We determine our asset retirement obligation on our oil and gas properties by calculating the present value of the estimated cash flows related to the estimated liability. Periodic accretion of the discount of the estimated liability on our oil and natural gas properties is recorded in the income statement.

The Company recorded the following activity related to the asset retirement obligations for the years ended December 31, 2009 and 2008 (in thousands):

	2009	2008
Liability for asset retirement obligations, beginning of year	$ 30,199	$ 27,645
Accretion expense	1,976	2,207
Change in estimates	(4,498)	(751)
Obligations for wells acquired and wells drilled	864	2,051
Obligations for wells sold or retired	(1,467)	(953)
Liability for asset retirement obligations, end of year	27,074	30,199
Less: current asset retirement obligation	711	1,093
Long-term asset retirement obligations	$ 26,363	$ 29,106

17. ***Income Taxes***

The Company accounts for income taxes under the liability method as prescribed by authoritative guidance set forth in Topic 740 of the Codification. Deferred tax liabilities and assets are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted rates expected to be in effect during the year in which the basis differences reverse. The realizability of deferred tax assets are evaluated quarterly and a valuation allowance is provided if it is more likely than not that the deferred tax assets will not give rise to future benefits in the Company s tax returns.

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18. ***Uncertain Tax Positions***

The Company follows guidance in Topic 740 of the Codification for its accounting for uncertain tax positions. Topic 740 prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the Company determines whether it is more-likely-than-not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based solely on the technical merits of the position. A tax position that meets the more-likely-than-not threshold is measured to determine the amount of benefit to be recognized in the financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

The cumulative effect of adopting Topic 740 was to be reported as an adjustment to the opening balance of retained earnings in the year of adoption. Accordingly, the Company recorded a $1.3 million decrease to retained earnings, with a corresponding increase to accrued interest related to uncertain tax positions upon adoption of FIN 48 on January 1, 2007.

A rollforward of activity from January 1, 2007 follows (in thousands):

Uncertain Tax Positions:	
Balance as of December 31, 2006	$ 9,633
Liability established at adoption of FIN 48	1,300
Additions for tax positions of prior periods	507
Decreases in tax positions in prior period	
Settlements	
Additions based on tax positions related to the current year	
Lapse of statute of limitations	(4,585)
Balance as of December 31, 2007	$ 6,855
Additions for tax positions of prior periods	127
Decreases in tax positions in prior period	
Settlements	
Additions based on tax positions related to the current year	
Lapse of statute of limitations	(6,982)
Balance as of December 31, 2008	$
Additions for tax positions of prior periods	
Decreases in tax positions in prior period	
Settlements	
Additions based on tax positions related to the current year	
Lapse of statute of limitations	
Balance as of December 31, 2009	$

The Company has no liability for unrecognized tax benefits recorded as of December 31, 2009 and there was no change to the Company s unrecognized tax benefits during the year ended December 31, 2009. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the statement of operations or statement of financial position as of December 31, 2009. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease within the next twelve months. Related to the unrecognized tax benefits noted above, the Company had recognized $1.3 million in accrued interest at the date of adoption. The amount of interest related to unrecognized tax benefits which was decreased due to expirations of applicable statutes of limitations was $0.9 million during the year ended December 31, 2007. Additional interest was accrued on balances in the years ended December 31, 2008 and 2007 in the amount of $0.1 million and $0.5 million, respectively. The Company recognizes related interest and penalties as a component of income tax expense.

Tax years open for audit by federal tax authorities as of December 31, 2009 are the years ended December 31, 2006, 2007 and 2008 and the tax years open for audit for state tax authorities as of December 31, 2009 are the years ended December 31, 2006, 2007 and 2008. Tax years ending prior to 2006 are open for audit to the extent that net operating losses generated in those years are being carried forward or utilized in an open year.

19. ***New Accounting Pronouncements***

In June 2009, the FASB implemented the Codification establishing the Codification as the single official source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with generally accepted accounting principles (GAAP), other than guidance issued by the SEC. The Codification became effective for interim and annual periods ending after September 15, 2009. As the Codification was not intended to change or alter existing GAAP, adoption did not have any substantive impact on the Company s financial position or results of operations. However, as a result of the Company s implementation of the Codification during the quarter ended September 30, 2009, previous references to new accounting standards and literature are no longer applicable in the notes to the consolidated financial statements and references will now refer to the appropriate topic of the Codification.

In December 2007, the FASB revised authoritative guidance on business combinations, as set forth in Topic 805 of the Codification. The revised guidance resulted in significant changes in financial accounting and reporting of business combination transactions. The guidance establishes principles and requirements for how an acquirer in a business combination: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. Adoption of the revised guidance on January 1, 2009 did not have an impact on current financial position or results of operations, but will impact the accounting for any future acquisitions.

In December 2007, the FASB issued authoritative guidance on noncontrolling interest in consolidated financial statements, as set forth in Topic 810 of the Codification. This guidance established accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Additionally, the guidance clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, consolidated net income is to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. Disclosure is also required on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. Adoption of the guidance on January 1, 2009 did not impact the Company s financial position or results of operations.

In March 2008, the FASB issued authoritative guidance changing the disclosure requirements for derivative instruments and hedging activities, as set forth in Topic 815 of the Codification. Among other requirements, the guidance requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for, and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. Adoption of the guidance on January 1, 2009 required enhanced disclosures about the Company s derivative instruments as disclosed in Note J.

In April 2009, the FASB issued authoritative guidance on interim disclosures about the fair value of financial instruments. The guidance requires quarterly disclosure of information about the fair value of certain

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financial instruments, as set forth in Topic 825 of the Codification. Adoption of the guidance during the second quarter of 2009 did not impact the Company s financial position or results of operations.

In May 2009, the FASB issued authoritative guidance on subsequent events, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date, but before the financial statements are issued or available to be issued. The guidance is set forth in Topic 855 of the Codification and is effective for fiscal years and interim periods after June 15, 2009. Adoption of the guidance in the second quarter of 2009 did not impact the Company s financial position or results of operations.

In January 2009, the FASB issued guidance on fair value disclosures to enhance disclosures surrounding the transfers of assets in and out of level 1 and level 2, to present more detail surrounding asset activity for level 3 assets and to clarify existing disclosure requirements. The new guidance is set forth in Topic 820 of the Codification and is effective for the Company beginning January 1, 2010. Adoption of the guidance will not have any impact on our financial position or statement of operations.

During June 2008, the FASB issued authoritative guidance on whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in computing basic earnings per share. The guidance was effective for fiscal years beginning after December 15, 2008, and interim periods within those years. Additionally, all prior period earnings per share must be adjusted retrospectively. As our restricted stock awards granted under our Long-Term Incentive Plan qualify as participating securities, we adopted the guidance during 2009, which resulted in an increase in our basic and diluted weighted average shares outstanding for the years ended December 31, 2009, 2008 and 2007. The impact of the adoption of the guidance is reflected in the following table:

	2009	2008	2007
Before adoption:			
Weighted average shares outstanding:			
Basic	75,251,399	70,629,452	41,240,021
Diluted	75,251,399	70,629,452	41,240,021
Earnings (loss) per share:			
Basic	$ (0.78)	$ (1.84)	$ (0.03)
Diluted	$ (0.78)	$ (1.84)	$ (0.03)
After adoption:			
Weighted average shares outstanding:			
Basic	77,601,057	72,234,750	42,087,617
Diluted	77,601,057	72,234,750	42,087,617
Earnings (loss) per share:			
Basic	$ (0.75)	$ (1.80)	$ (0.03)
Diluted	$ (0.75)	$ (1.80)	$ (0.03)

On December 31, 2008, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting, which revises disclosure requirements for oil and gas companies. In addition to changing the definition and disclosure requirements for oil and gas reserves, the new rules change the requirements for determining oil and gas reserve quantities. These rules permit the use of new technologies to determine proved reserves under certain criteria and allow companies to disclose their probable and possible reserves. The new rules also require companies to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit. The new rules also require that oil and gas reserves be reported and the full cost ceiling limitation be calculated using a twelve-month average price rather than period-end prices. The new rules are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Additionally, the FASB issued authoritative guidance on oil and gas reserve estimation and disclosures, as set forth in Topic 932 of the Codification to align with the requirements of the SEC s revised rules. The Company implemented the new disclosure requirements and requirements for estimating reserves related to the Company s oil and natural gas operations as disclosed in Note M.

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20. *Subsequent Events*

The Company evaluates events and transactions after the balance sheet date but before the financial statements are filed with the U.S. Securities and Exchange Commission.

B SIGNIFICANT ACQUISITIONS

1. *Ascent Energy Inc.*

On November 29, 2007, RAM completed the acquisition of Ascent Energy Inc (Ascent), a company engaged in exploration and development of oil and natural gas properties, and the production of oil and natural gas. RAM s investment in the Ascent acquisition was valued at $303.8 million, and included 18,783,344 shares of RAM common stock and warrants to purchase 6,200,000 shares of RAM common stock at an exercise price of $5.00 per share, exercisable at any time on or prior to May 11, 2008. Sales proceeds of $20.0 million were placed in escrow as a source of funds to adjust for Ascent s closing date working capital and to indemnify RAM against, among other things, breaches of covenants, representations and warranties by Ascent. As a result of the post-closing working capital reconciliation and the interim settlement of certain claims, at December 31, 2009, approximately $0.2 million principal and accrued interest remained in the escrow account. Through this transaction, RAM acquired properties and assets located in Texas, Oklahoma, Louisiana and the Appalachian region. The Company financed $187.0 million of the consideration paid in connection with the acquisition through borrowings under its new credit facility with Guggenheim Corporate Funding, LLC, for itself and as agent on behalf of a group of lenders.

The acquisition was accounted for using the purchase method in accordance guidance provided in Topic 805 of the Codification. The initial acquisition cost, the final allocation to assets and liabilities are as follows (in thousands):

	Final Allocation
Cash	$ 201,673
Direct acquisition costs	1,304
Fair value of shares of RAM common stock	97,016
Fair value of shares of RAM warrants	4,049
Net receivable due from escrow	(271)
Total Acquisition Cost	$ 303,771
Fair Value of Assets and Liabilities Acquired:	
Current assets	$ 12,680
Proved oil and natural gas properties and equipment, using full cost accounting	347,570
Unevaluated oil and gas properties	26,254
Other property and equipment	1,466
Other assets	1,339
Current liabilities	(16,414)
Long-term asset retirement obligations	(13,847)
Deferred tax liability	(54,377)
Contingent liability	(900)
Total Purchase Price	$ 303,771

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Operating results for Ascent have been included in the consolidated statements of operations since the date of acquisition. The following unaudited pro forma results of operations assume that the Ascent merger occurred on January 1, 2007. The unaudited pro forma consolidated financial information is presented for illustrative purposes only and does not indicate the financial results of the combined companies had the companies actually been combined (in thousands, except per share amounts):

	Year ended December 31, 2007 (unaudited)
Revenue	$ 116,216
Net loss	$ (17,396)
Basic and diluted loss per share	$ (0.31)

2. ***Layton acquisition.***
On May 15, 2007 the Company purchased a 100% working interest in certain oil and natural gas properties in the Permian Basin area of Southeast New Mexico and West Texas on which there are 120 wells. The aggregate purchase price for these properties was $18.7 million.

C LONG-TERM DEBT

Long-term debt at December 31 consists of the following (in thousands):

	2009	2008
Credit facility	$ 245,730	$ 250,387
Accrued payment-in-kind interest	262	
Installment loan agreements	175	309
	246,167	250,696
Less amount due within one year	126	160
	$ 246,041	$ 250,536

The amounts of required principal payments as of December 31, 2009, are as follows (in thousands):

2010	$ 126
2011	135,038
2012	111,003
2013	
	$ 246,167

1. ***Senior Notes***
In February 1998, the Company completed the sale of $115.0 million of 11.5% Senior Notes due 2008 in a public offering of which $28.4 million remained outstanding at December 31, 2007. These notes were retired at maturity on February 15, 2008 using proceeds from the Company s revolving credit facility.

2. *Revolving Credit Facility*

New Credit Facility. In November 2007, in conjunction with the Ascent acquisition, the Company entered into a new $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. The facility includes a $250.0 million revolving credit facility and a $200.0 million term loan facility and an additional $50.0 million available under the term loan as requested by the Company and approved by the lenders. The initial amount of the $200.0 million term loan was advanced at closing. The borrowing base under the revolving credit facility initially was set at $175.0 million, a portion of which was advanced at the closing of the Ascent acquisition. Borrowings under the new facility were used to refinance RAM Energy s existing indebtedness, fund the cash requirements in connection with the closing of the Ascent acquisition, and for working capital and other general corporate purposes. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the four-year term of the revolver, and initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The term loan provides for payments of interest only during its term, with the initial interest rate being LIBOR plus 7.5%. The $175.0 million borrowing base under the revolver was reaffirmed in September 2009.

Advances under the new facility are secured by liens on substantially all properties and assets of the Company and its subsidiaries. The loan agreement contains representations, warranties and covenants customary in transactions of this nature, including restrictions on the payment of dividends on our capital stock and financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to total indebtedness. The Company is required to maintain commodity hedges with respect to not less than 50%, but not more than 85%, of the Company s projected monthly production volumes on a rolling 30-month basis, until the leverage ratio is less than or equal to 2.0 to 1.0. During May 2008, the Company reduced its outstanding balance on the term facility by $86.6 million of net proceeds, which it realized upon the exercise of 17,617,331 warrants. See Note F.

On June 26, 2009, the Company entered into the Second Amendment to the credit facility. The Second Amendment amends certain definitions and certain financial and negative covenant terms providing greater flexibility for the Company through the remaining term of the facility. Additionally, the Second Amendment increased the interest rates applicable to borrowings under both the revolver and term loans. Advances under the revolver will bear interest at LIBOR, with a minimum LIBOR rate, or floor, of 1.5%, plus a margin ranging from 2.25% to 3.0% based on a percentage of usage. The term loan will bear interest at LIBOR, also with a floor of 1.5%, plus a margin of 8.5%, and an additional 2.75% of payment-in-kind interest that will be added to the term loan principal balance on a monthly basis and paid at maturity. The Company was in compliance with all of its covenants in the credit facility at December 31, 2009. At December 31, 2009, $135.0 million was outstanding under the revolving credit facility and $111.0 million was outstanding under the term facility, including $0.3 million accrued payment-in-kind interest.

D LEASES

The Company leases office space and certain equipment under non-cancelable operating lease agreements that expire on various dates through 2014. Approximate future minimum lease payments for operating leases at December 31, 2009 are as follows (in thousands):

Year Ending December 31,	
2010	$ 1,253
2011	1,211
2012	1,195
2013	1,076
2014	41
	$ 4,776

Rent expense of approximately $1.3 million, $1.2 million, and $0.5 million was incurred under operating leases in the years ended December 31, 2009, 2008, and 2007, respectively. In 2010, the Company sub-leased a portion of its leased office space for the duration of the operating lease agreement. Approximate future minimum lease receipts for the sub-lease at December 31, 2009 are $0.1 million, $0.2 million, $0.2 million and $0.1 million for 2010, 2011, 2012 and 2013, respectively.

E DEFINED CONTRIBUTION PLAN

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all of its employees. The plan allows eligible employees to contribute up to 100% of their annual compensation, not to exceed the maximum amount permitted by IRS regulations. Employer contributions to the plan are discretionary. The Company provided matching contributions to the plan in 2009, 2008, and 2007 of $0.7 million, $0.6 million and $0.3 million, respectively.

F CAPITAL STOCK

On May 8, 2006, the shareholders of the Company approved the Company s 2006 Long-Term Incentive Plan (the Plan), effective upon the consummation of the Company s acquisition by merger of RAM Energy. Under the terms of the Plan, at such time as restricted stock awards vest, the grantee has the right to request the Company to repurchase, at the closing market price of the Company s common stock as of the vesting date, the number of vested shares necessary to satisfy minimum income tax withholding requirements. Pursuant to this provision, since inception of the Plan in 2006, the Company has repurchased, upon vesting, a total of 173,806 shares of common stock at an average price of $5.07 per share. The shares purchased by the Company are held as treasury shares.

On February 13, 2007, the Company completed a public offering in which it issued 7,500,000 shares of its common stock, priced at $4.00 per share. Net proceeds of the offering were $27.4 million and were used to provide additional working capital for general corporate purposes, including acquisition, development, exploitation and exploration of oil and natural gas properties, and reduction of indebtedness.

On November 29, 2007, the Company acquired Ascent in exchange for the issuance of 18,783,344 shares of common stock, warrants to purchase 6,200,000 shares of common stock at an exercise price of $5.00 per share, exercisable on or prior to May 11, 2008, and $202.8 million in cash, including direct acquisition costs.

The Company had outstanding warrants to purchase 18,848,800 shares of its common stock (including the warrants issued in connection with the Ascent acquisition) at an exercise price of $5.00 per share, of which 17,617,331 were exercised prior to the May 12, 2008 expiration date, resulting in net proceeds to the Company of $86.6 million. Proceeds of the exercise were used to pay down the term loan portion of the Company s credit facility. The remaining 1,231,469 warrants expired and are no longer outstanding.

The Company had outstanding options to purchase up to 275,000 units at any time on or prior to May 11, 2009 at an exercise price of $9.90 per unit, with each unit consisting of one share of the Company s common stock and two warrants. All of the unit purchase options expired unexercised.

G INCOME TAXES

The (provision) benefit for income taxes is comprised of (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Current	$ (518)	$ (912)	$ (1,313)
Deferred	16,865	92,595	9,165
Benefit for income tax expense	$ 16,347	$ 91,683	$ 7,852

The provision for income taxes differs from the amount computed by applying the statutory federal income tax rate to income before provision for income taxes. The significant differences between pre-tax book income and taxable book income relate to non-deductible personal expenses, meals and entertainment expenses, state income taxes and previously unrecognized tax benefits.

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The sources and tax effects of the differences are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Income tax benefit at the federal statutory rate (34%)	$ 25,408	$ 75,356	$ 3,039
State income tax benefit, net of federal benefit	(508)	6,033	732
Meals and entertainment expense	(27)	(102)	(18)
Non-deductible dues	12	(33)	(13)
Previously unrecognized tax benefits		11,613	3,715
Interest on previously unrecognized tax benefits		(127)	363
Valuation allowance	(7,433)	(2,234)	
Other	(1,105)	1,177	34
Income tax benefit	$ 16,347	$ 91,683	$ 7,852

The Company s income tax benefit was computed based on the federal statutory rate and the average state statutory rates, net of the related federal benefit. Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

Significant components of the Company s deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2009	2008
Deferred tax assets:		
Current:		
Derivative liabilities	$ 2,226	$
Accrued expenses and other	2,675	2,672
Total current deferred tax assets	$ 4,901	$ 2,672
Valuation allowance	(1,138)	(81)
Net current deferred tax assets	$ 3,763	$ 2,591
Noncurrent:		
Depreciable/depletable property, plant and equipment	$ 3,024	$
Net operating loss carryforward	36,644	33,735
Accrued liabilities and other	1,688	4,326
Total noncurrent deferred tax assets	$ 41,356	$ 38,061
Valuation allowance	(9,603)	(1,150)
Net noncurrent deferred tax assets	$ 31,753	$ 36,911
Deferred tax liabilities:		
Current:		
Prepaid expenses and other	$ (232)	$ (8,370)
Total current deferred tax liability	(232)	(8,370)
Noncurrent:		
Depreciable/depletable property, plant and equipment	$	$ (13,072)

Other	(180)	179
Total noncurrent deferred tax liabilities	$ (180)	$ (12,893)
Net deferred tax liability	$ (412)	$ (21,263)
Net deferred tax asset (liability)	$ 35,104	$ 18,239

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As of December 31, 2009, the Company anticipates net operating loss carryforwards of approximately $160.0 million for federal income tax reporting purposes, $132.7 million of which were an inherited attribute from the Ascent acquisition during 2007. If not used, the net operating losses will generally expire between 2020 and 2029. These net operating loss carryforwards are subject to the ownership change limitation provisions of Section 382 of the Internal Revenue Code. Based on the value of Ascent at the time of the acquisition, and the annual limitation on utilization of losses imposed by Section 382, and other increases for anticipated recognized built-in gains, it is estimated that approximately $62.9 million of these net operating losses will expire without being utilized; accordingly, no deferred tax asset has been established for the amount of net operating losses that are not expected to be utilized under the applicable provisions of the tax law prior to their expiration. In addition, the Company has generated net operating loss carryforwards for state income tax purposes, which the Company believes will more likely than not be realized during the relevant carryforward periods; however, such amounts have not been separately disclosed in the financial statements as the Company does not believe that these net operating losses are material to the amounts presented herein.

A valuation allowance has been established with respect to the portion of the net operating losses for which the Company currently does not reasonably believe under the deferred tax asset realization criteria set forth in Topic 740 that it will more likely than not realize a benefit in future periods. During the year ended December 31, 2009, the Company recorded an increase in the valuation allowance of $9.5 million.

H COMMITMENTS AND CONTINGENCIES

Sacket v. Great Plains Pipeline Company, et al. This was a class action lawsuit on behalf of certain royalty owners in which RAM Energy, together with certain of its subsidiaries and affiliates, were defendants. In the lawsuit, the plaintiff alleged that the royalty payments to landowners for oil and natural gas produced from wells connected to a RAM Energy subsidiary s natural gas, oil and saltwater pipeline system in Woods, Alfalfa and Major Counties, Oklahoma, were calculated on a price that was lower than the price at which the production from the related wells was resold by the subsidiary. RAM Energy and its subsidiaries sold their interests in the affected leases effective December 1, 2001. On September 18, 2008, RAM Energy, together with the other defendants in the lawsuit, entered into a settlement agreement with the plaintiff, individually and as representative of the putative class, pursuant to which the defendants agreed to pay an aggregate $25.0 million in settlement of the lawsuit. RAM Energy and its subsidiaries agreed to pay $16.0 million of the settlement amount, with the unrelated third party defendants paying the remaining $9.0 million. On March 5, 2009, following a hearing at which the Court received evidence concerning the fairness of the proposed settlement to the plaintiff class, the Court entered an order approving the settlement and the related plan of allocation and distribution of the settlement fund. On April 4, 2009, the settlement became final, promptly after which the plan of distribution was implemented and the settlement funds distributed to the members of the plaintiff class.

In conjunction with the Company s May 8, 2006 acquisition of RAM Energy, the former stockholders of RAM Energy deposited in escrow 3,200,000 shares of the Company s common stock to secure their potential indemnity obligations to the Company, including any loss the Company might sustain in the pending litigation. Pursuant to the terms of the escrow agreement, at such time as a claim against the escrow matures for payment, the former stockholders of RAM Energy had the option of substituting cash for all or a portion of their escrowed shares, based on the average closing price of the Company s common stock for the ten trading days ending on the last trading day prior to the date the Company s indemnity claim against the escrow is paid (defined as Fair Market Value), in which event the escrowed shares for which cash is substituted would be delivered to the stockholders and the cash paid to the Company out of escrow. On April 7, 2009, the Company made a claim against the escrow for all of the escrowed shares. Also on April 7, 2009, the former stockholders of RAM Energy notified the escrow agent that they would substitute cash, at a Fair Market Value of $0.74 per share, for a total of 316,190 shares of their Company common stock held in escrow.

On April 8, 2009, the escrow agent initiated the transfer to the Company, in satisfaction of the indemnification obligation of the former RAM stockholders, of a total of 2,883,810 shares of Company common stock and $0.2 million in cash, less the fees and expenses of the escrow agent. The shares of common stock received by the Company were recorded as treasury shares.

During 2008, the Company recorded a contingent liability of $16.0 million for its share of the settlement amount and a receivable of $2.8 million in other current assets representing the value of the escrowed shares based on the closing price of $0.88 per share on December 31, 2008. The Company also recorded a charge to other expense of $13.2 million for the difference between the settlement liability and the value of the escrowed shares. During the first quarter of 2009, the Company recorded a charge to other expense of $0.4 million and adjusted the receivable from $2.8 million to $2.4 million to adjust the Fair Market Value of the escrowed shares to reflect the final settlement due of $0.74 per share.

Rathborne Land Company, et al., v. Ascent Energy Inc., et al. Ascent Energy Inc. and its Ascent Energy Louisiana, LLC subsidiary were sued for lease cancellation and damages for failure to explore and develop the plaintiff s lease. By Opinion dated December 31, 2008, the court found in favor of the plaintiff and against the defendants. On June 1, 2009, the court entered judgment against the defendants in the amount of $4.6 million and shortly thereafter the Company filed an appeal with the United States Court of Appeals for the Fifth Circuit. The Company also filed a motion to stay the judgment pending final disposition on appeal and to permit the posting of a cash bond as security for the stay, which motion was granted by the court.

In conjunction with the Company s November 29, 2007 acquisition of Ascent, the former stockholders and note holders of Ascent deposited $20.0 million in escrow to secure their obligation to indemnify the Company with respect to certain liabilities and obligations of Ascent, including any loss, cost, liability or expense incurred by the Company in connection with this and other pending litigation, subject to a sharing arrangement. After giving effect to such sharing arrangement with respect to previously settled litigation, the Company and the former Ascent owners will share equally the first $1.8 million of any losses attributable to this lawsuit and the former Ascent owners, out of the escrow, will bear the remaining portion of any loss so incurred, up to the remaining balance in the escrow fund. On June 18, 2009, the defendants arranged for the posting of a cash security bond with the registry of the trial court in the amount of $5.5 million, being 120% of the amount of the judgment, as required by court rule. By agreement with the representative of the former Ascent stockholders and note holders, the Company posted the sum of $0.9 million toward the security deposit and the remaining sum of $4.6 million was posted out of the escrow fund. All remaining funds in the escrow account, less the sum of approximately $0.2 million (which was retained in the escrow account to cover additional and incidental fees and expenses related to the Rathborne litigation), were distributed to the Ascent stockholders and note holders per the terms of the escrow agreement. During the fourth quarter of 2008, the Company recorded a contingent liability of $0.9 million related to this litigation.

The Company is also involved in legal proceedings and litigation in the ordinary course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company s financial position or results of operations.

I FAIR VALUE MEASUREMENTS

The Company measures the fair value of its derivative instruments according to the fair value hierarchy, as set forth in Topic 820 of the Codification. Topic 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The fair value measurement of our net derivative liabilities as of December 31, 2009 was $4.8 million and of our net derivative assets as of December 31, 2008 was $25.5 million, based on Level 2 criteria. See Note J. As of December 31, 2008, the fair value measurement of escrowed shares recorded in other current assets was $2.8 million, based on Level 1 criteria.

At December 31, 2009, the carrying value of cash, receivables and payables reflected in the Company s consolidated financial statements approximates fair value due to their short-term nature. Additionally, the carrying value of the Company s long-term debt under the credit facility approximates fair value because the credit facility carries a variable interest rate based on market interest rates. See Note C for discussion of long-term debt.

J DERIVATIVE CONTRACTS

The Company periodically utilizes various hedging strategies to manage the price received for a portion of its future oil and natural gas production to reduce exposure to fluctuations in oil and natural gas prices and to achieve a more predictable cash flow.

During 2009, 2008 and 2007, the Company entered into numerous derivative contracts to manage the impact of oil and natural gas price fluctuations and as required by the terms of its credit facility.

The Company did not designate these transactions as hedges. Accordingly, all gains and losses on the derivative instruments during 2009, 2008 and 2007 have been recorded in the statements of operations.

The Company s derivative positions at December 31, 2009, consisting of put/call collars and put options, also called bare floors as they provide a floor price without a corresponding ceiling, are shown in the following table:

	Crude Oil (Bbls)					Natural Gas (Mmbtu)				
	Floors		Ceilings			Floors		Ceilings		
	Per Day(1)	Price	Per Day	Price	Months Covered	Per Day(1)	Price	Per Day	Price	Months Covered
Collars										
2010	1,503	$ 53.74	1,503	$ 80.57	January-December	5,288	$ 5.00	5,288	$ 9.23	January-June, November-December
2011		$ 0.00		$		4,959	$ 5.00	4,959	$ 9.60	January-June

	Bare Floors			Bare Floors		
Year	Per Day(1)	Price	Months Covered	Per Day(1)	Price	Months Covered
2010	1,121	$ 64.84	January-March, July-December	5,452	$ 4.46	April - December
2011	744	$ 60.00	January-June		$ 0.00	

(1) Per day amounts are calculated based on a 365-day year.

The Company estimates the fair value of its derivative instruments based on published forward commodity price curves as of the date of the estimate, less discounts to recognize present values. For the year ended December 31, 2008 and subsequent periods, the Company estimated the fair value of its derivatives using a pricing model which also considered market volatility, counterparty credit risk and additional criteria in determining discount rates. See Note I. For the year ended December 31, 2008 and subsequent periods, the discount rate used in the discounted cash flow projections was based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The counterparty credit risk was determined by calculating the difference between the derivative counterparty s bond rate and published bond rates. The Company incorporates its credit risk when the derivative position is a liability by using its libor spread rate.

Gross fair values of the Company s derivative instruments, prior to netting of assets and liabilities subject to a master netting arrangement, as of December 31, 2009 and 2008 and the consolidated statements of operations for the years ended December 31, 2009, 2008 and 2007 are as follows (in thousands):

CONSOLIDATED BALANCE SHEETS

Gross Assets and Liabilities	Balance Sheet Location	Fair Value as of December 31, 2009	2008
Current Assets Derivative assets	Current Liabilities Derivative liabilities	$ 413	$
Current Assets Derivative assets	Current Assets Derivative assets		22,674
Other Assets Derivative assets	Long-Term Liabilities Derivative liabilities	200	
Other Assets Derivative assets	Long-Term Assets Derivative assets		5,378
Current Liabilities Derivative liabilities	Current Liabilities Derivative liabilities	(4,884)	
Current Liabilities Derivative liabilities	Current Assets Derivative assets		(1,668)
Long-Term Liabilities Derivative liabilities	Long-Term Liabilities Derivative liabilities	(558)	
Long-Term Liabilities Derivative liabilities	Long-Term Assets Derivative assets		(847)
Total Derivatives Not Designated as Hedging Instruments		$ (4,829)	$ 25,537

CONSOLIDATED STATEMENTS OF OPERATIONS

Location	Years Ended December 31, 2009	2008	2007
Revenue Unrealized gains (losses) on derivatives	$ (30,561)	$ 33,257	$ (10,056)
Revenue Realized gains (losses) on derivatives	$ 19,255	$ (10,472)	$ (2,669)

K LIQUIDITY

As of December 31, 2009, the Company has an accumulated deficit of $217.3 million and a working capital deficit of $14.4 million. Management believes that borrowings currently available to the Company under the Company s credit facilities and anticipated cash flows from operations will be sufficient to satisfy its currently expected capital expenditures, working capital, and debt service obligations through 2010. Due to our Modified EBITDA, the financial covenants set forth in our credit facility limit us to additional borrowings under our revolving credit facility as of December 31, 2009 of $25.3 million of our $40.0 million availability. We will be unable to borrow the additional amounts under our borrowing base until our Modified EBITDA for the preceding four fiscal quarters equals or exceeds $63.6 million. The actual amount and timing of future capital requirements may differ materially from estimates as a result of, among other things, changes in product pricing and regulatory, technological and competitive developments. Sources of additional financing may include commercial bank borrowings, vendor financing and the sale of oil and natural gas properties or equity or debt securities. Management cannot assure that any such financing will be available on acceptable terms or at all.

L SHARE-BASED COMPENSATION

The Company accounts for share-based payment accruals under authoritative guidance on stock compensation, as set forth in Topic 718 of the Codification. The guidance requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

On May 8, 2006, the Company s stockholders approved its 2006 Long-Term Incentive Plan (the Plan). The Company reserved a maximum of 2,400,000 shares of its common stock for issuances under the Plan. The Plan includes a provision that, at the request of a grantee, the Company may repurchase shares to satisfy the

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grantee s federal and state income tax withholding requirements. All repurchased shares will be held by the Company as treasury stock. On May 8, 2008, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2,400,000 to 6,000,000. As of December 31, 2009, a maximum of 2,409,426 shares of common stock remained reserved for issuance under the Plan.

The number of shares repurchased and their weighted average prices for the three year period ended December 31, 2009 were as follows:

Shares Repurchased

Year ended	Number	Weighted Average Closing Price
December 31, 2007	33,616	$ 5.28
December 31, 2008	20,549	$ 3.98
December 31, 2009	21,541	$ 1.33

A summary of the status of the non-vested shares as of December 31, 2009, and changes during the three year period ended December 31, 2009, is presented below:

Nonvested Shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2007	646,805	$ 5.06
Granted	300,262	$ 4.46
Vested	(125,606)	$ 5.06
Forfeited	(18,775)	$ 5.06
Nonvested at December 31, 2007	802,686	$ 4.28
Granted	1,104,800	$ 4.84
Vested	(297,849)	$ 4.95
Forfeited	(141,393)	$ 5.03
Nonvested at December 31, 2008	1,468,244	$ 4.79
Granted	1,343,000	$ 0.95
Vested	(429,351)	$ 4.81
Forfeited	(17,900)	$ 1.20
Nonvested at December 31, 2009	2,363,993	$ 2.64

Each grant vests in equal increments over periods ranging from eight months to five years from the date of grant. At the request of certain of the grantees, the Company repurchased a portion of the vested shares at the closing market price of the Company s common stock as of the vesting date, to satisfy the requesting grantees federal and state income tax withholding requirements. The repurchased shares were held by the Company as treasury stock at December 31, 2009.

As of December 31, 2009, the Company had $4.6 million of unrecognized share-based compensation related to awards granted under the Plan. That cost is expected to be recognized over a weighted-average period of two years. The related compensation expense recognized during the years ended December 31, 2009, 2008 and 2007 was $2.2 million, $2.6 million and $1.0 million, respectively.

In March 2008, John L. Cox, a senior executive officer of the Company passed away. On April 4, 2008, the Compensation Committee of the Company s Board of Directors approved the immediate vesting in full of all restricted shares held by Mr. Cox at the time of his death. The number of shares vested totaled 95,336, and the Company recognized $0.4 million of share-based compensation related to the vesting of these shares in April 2008.

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M SUPPLEMENTARY OIL AND NATURAL GAS RESERVE INFORMATION (UNAUDITED)

The Company has interests in oil and natural gas properties that are principally located in Texas, Louisiana and Oklahoma. The Company does not own or lease any oil and natural gas properties outside the United States of America.

The Company retains independent engineering firms to provide year-end estimates of the Company s future net recoverable oil, natural gas and natural gas liquids reserves. Estimated proved net recoverable reserves as shown below include only those quantities that can be expected to be commercially recoverable. Estimated reserves for the year ended December 31, 2009 were computed using benchmark prices based on the unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas during each month of 2009, as required by SEC Release No. 33-8995 *Modernization of Oil and Gas Reporting*, effective December 31, 2009, while estimated reserves for the years ended December 31, 2007 and 2008 were based on oil and natural gas spot prices as of the end of the period presented. Costs were estimated using costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods.

Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure is required for re-completion.

Capitalized costs relating to oil and natural gas producing activities and related accumulated depreciation and amortization at December 31 are summarized as follows (in thousands):

	2009	2008	2007
Proved oil and natural gas properties	$ 702,502	$ 683,341	$ 573,470
Unevaluated oil and natural gas properties			26,895
Accumulated depreciation, amortization and impairment	(456,720)	(378,445)	(63,480)
	$ 245,782	$ 304,896	$ 536,885

Costs incurred in oil and natural gas producing activities for the years ended December 31 are as follows (in thousands, except per equivalent oil barrel):

	2009	2008	2007
Acquisition of proved properties	$ 1,311	$ 10,091	$ 299,573
Acquisition of unproved properties		2,691	24,642
Proceeds from sale of unproved properties			
Development costs	28,239	57,084	12,921
Exploration costs	321	14,857	7,659
Exploration in progress			
Sale of producing properties	(6,120)	(2,950)	(170)
Additional asset retirement obligation	864	2,051	17,328
	$ 24,615	$ 83,824	$ 361,953
Amortization rate per equivalent oil barrel	$ 12.06	$ 17.89	$ 12.86

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Net quantities of proved and proved developed reserves of oil and natural gas, including condensate and natural gas liquids, are summarized as follows:

	Crude Oil (Thousand Barrels)	Natural Gas (Million Cubic Feet)	Natural Gas Liquids (Thousand Barrels)
December 31, 2006	10,796	33,199	2,123
Extensions and discoveries	3	1,927	143
Sales of reserves in place		(117)	
Purchases of reserves in place	8,688	58,628	1,046
Revisions of previous estimates	831	2,506	1,143
Production	(774)	(2,785)	(184)
December 31, 2007	19,544	93,358	4,271
Extensions and discoveries	631	18,647	1,071
Sales of reserves in place	(85)	(701)	
Purchases of reserves in place	151	135	
Revisions of previous estimates	(4,769)	(8,405)	(663)
Production	(1,187)	(6,082)	(354)
December 31, 2008	14,285	96,952	4,325
Extensions and discoveries	1,771	10,070	508
Sales of reserves in place	(15)	(3,808)	
Purchases of reserves in place			
Revisions of previous estimates	(836)	(7,993)	556
Production	(1,138)	(5,994)	(406)
December 31, 2009	14,067	89,227	4,983
Proved developed reserves:			
December 31, 2007	13,552	50,990	2,565
December 31, 2008	9,235	57,635	2,705
December 31, 2009	8,814	46,159	2,788

The Company added 3.9 million barrels of oil equivalent in proved reserve extensions and discoveries in 2009, primarily as a result of success in development drilling in the La Copita field of South Texas and the mature oil area of Electra/Burkburnett in North Texas. Extensions and discoveries in 2008 were due to upgrading probable and possible locations to the proved undeveloped category and from drilling many wells that were not carried as proved prior to being drilled.

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Transition Impact of Application of New Oil and Gas Rules

In addition to reporting the Company s reserves using the first-day-of-the-month average prices for 2009, as required by SEC regulations, for comparative purposes we are presenting an alternate price case using year-end 2009 prices of $79.36 per barrel and $5.79 per thousand cubic feet, consistent with SEC guidelines in effect for calendar year 2008 and prior years. At year-end 2009 prices were well above the first-day-of-the-month average prices of $61.18 per barrel and $3.87 per thousand cubic feet.

The table below reflects the Company s December 31, 2009 proved reserves quantities using year-end 2009 pricing:

	Crude Oil (Thousand Barrels)	Natural Gas (Million Cubic Feet	Natural Gas Liquids (Thousand Barrels)
Proved developed producing	9,403	43,606	2,856
Proved developed non producing	632	6,216	97
Proved undeveloped	5,706	49,786	2,319
Total Proved	15,741	99,608	5,272
Developed	10,035	49,822	2,953
% Developed	64%	50%	56%

Applying last year s methodology of using year-end prices, the Company s proved reserves December 31, 2009 would have reflected an increase of 8% over December 31, 2008 levels. Additionally, approximately 750 barrels of oil equivalent of proved undeveloped reserves were eliminated due to the SEC s new five-year scheduling rule. The majority of these reserves are in smaller secondary recovery waterflood projects.

The following is a summary of a standardized measure of discounted net cash flows related to the Company s proved oil and natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves for the year ended December 31, 2009 were computed using benchmark prices based on the unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas during each month of 2009, as required by SEC Release No. 33-8995, Modernization of Oil and Gas Reporting, effective December 31, 2009, while estimated cash flows for the years ended December 31, 2007 and 2008 were based on oil and natural gas spot prices as of the end of the period presented. Future development and production costs attributable to the proved reserves were estimated assuming that existing conditions would continue over the economic lives of the individual leases and costs were not escalated for the future. Estimated future income tax expenses were calculated by applying future statutory tax rates (based on the current tax law adjusted for permanent differences and tax credits) to the estimated future pretax net cash flows related to proved oil and natural gas reserves, less the tax basis of the properties involved.

The Company cautions against using this data to determine the fair value of its oil and natural gas properties. To obtain the best estimate of fair value of the oil and natural gas properties, forecasts of future economic conditions, varying discount rates, and consideration of other than proved reserves would have to be incorporated into the calculation. In addition, there are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production that impair the usefulness of the data.

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The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves at December 31 are summarized as follows (in thousands):

	2009	2008	2007
Future cash inflows	$ 1,314,714	$ 1,253,537	$ 2,722,099
Future production costs	(535,784)	(472,191)	(824,576)
Future development costs	(148,956)	(145,086)	(146,734)
Future income tax expenses	(123,943)	(103,434)	(574,169)
Future net cash flows	506,031	532,826	1,176,620
10% annual discount for estimated timing of cash flows	(231,797)	(248,373)	(578,225)
Standardized measure of discounted future net cash flows	$ 274,234	$ 284,453	$ 598,395

The following are the principal sources of change in the standardized measure of discounted future net cash flows of the Company for each of the three years in the period ended December 31 (in thousands):

	2009	2008	2007
Standardized measure of discounted future net cash flows at beginning of year	$ 284,453	$ 598,395	$ 179,741
Changes during the year:			
Sales and transfers of oil and natural gas produced, net of production costs	(55,393)	(134,180)	(55,434)
Net changes in prices and production costs	1,272	(538,042)	181,475
Extensions and discoveries, less related costs	31,264	77,239	11,444
Development costs incurred and revisions	28,602	(2,973)	976
Sales of reserves in place	(5,598)	(5,143)	
Purchases of reserves in place		3,494	435,261
Revisions of previous quantity estimates	(18,323)	(81,073)	41,042
Net change in income taxes	(24,245)	275,581	(223,002)
Accretion of discount	32,202	91,155	26,892
Net change	(10,219)	(313,942)	418,654
Standardized measure of discounted future net cash flows at end of year	$ 274,234	$ 284,453	$ 598,395

Prices used in computing these calculations of future cash flows from estimated future production of proved reserves were $58.63, $44.15, and $93.90 per barrel of oil at December 31, 2009, 2008, and 2007, respectively, $3.76, $5.33, and $7.00 per thousand cubic feet of natural gas at December 31, 2009, 2008, and 2007, respectively and $31.03, $23.59, and $54.69 per barrel of natural gas liquids at December 31, 2009, 2008, and 2007, respectively.

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N QUARTERLY DATA (UNAUDITED)

	2009 - Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands except per share data)			
Net revenue	$ 25,516	$ 25,131	$ 10,419	$ 26,012
Net operating expenses	23,357	24,300	23,061	72,142
Operating income (loss)	2,159	831	(12,642)	(46,130)
Interest expense	(5,820)	(5,561)	(3,601)	(3,608)
Interest income	13	40	9	20
Other income (expense)	89	10	(106)	(433)
Loss before income taxes	(3,559)	(4,680)	(16,340)	(50,151)
Income tax provision (benefit)	9,062	(1,561)	(3,055)	(20,793)
Net income (loss)	$ (12,621)	$ (3,119)	$ (13,285)	$ (29,358)
Basic net loss applicable to common stockholders per common share	$ (0.16)	$ (0.04)	$ (0.18)	$ (0.38)
Diluted net loss applicable to common stockholders per common share	$ (0.16)	$ (0.04)	$ (0.18)	$ (0.38)

	2008 - Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands except per share data)			
Net revenue	$ 69,653	$ 83,509	$ 16,645	$ 36,050
Net operating expenses	300,150	29,868	30,989	28,976
Operating income (loss)	(230,497)	53,641	(14,344)	7,074
Interest expense	(5,006)	(4,817)	(6,197)	(8,162)
Interest income	22	38	75	73
Other expense	(6,449)	(6,733)	(205)	(149)
Income (loss) before income taxes	(241,930)	42,129	(20,671)	(1,164)
Income tax provision (benefit)	(89,874)	13,641	(14,809)	(641)
Net income (loss)	$ (152,056)	$ 28,488	$ (5,862)	$ (523)
Basic net income (loss) applicable to common stockholders per common share	$ (1.94)	$ 0.37	$ (0.08)	$ (0.01)
Diluted net income (loss) applicable to common stockholders per common share	$ (1.94)	$ 0.37	$ (0.08)	$ (0.01)

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

No items to report.

Item 9A. ***Controls and Procedures***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Disclosure Controls and Procedures. We maintain controls and procedures designed to ensure that information required to be disclosed in the reports we file with the U.S. Securities and Exchange Commission (SEC), is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act) was performed as of the end of the period covered by this report. This evaluation was performed by our management, with the participation of our Chief Executive Officer and Chief Financial Officer. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures were effective at December 31, 2009. However, in November of 2009, we identified a material weakness in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15-d15(f)) in connection with the occurrence of an error in our estimate of proved oil and natural gas reserves for the year ended December 31, 2008. As a result of this material weakness, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2008, our disclosure controls and procedures were not effective. We have described below the actions we have taken to remediate the material weakness so identified.

Management s Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) and 15-d15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements. Our internal controls are designed to provide reasonable assurance that our assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of competent business process owners supported by competent and qualified external resources used to assist in testing the operating effectiveness of our internal control over financial reporting.

Our management, including our Chief Executive Officer and Chief Financial Officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Our management concluded that the design and operations of our internal control over financial reporting at December 31, 2009 were effective and provide reasonable assurance the books and records accurately reflect the transactions of the Company.

However, in November of 2009, we identified a material weakness in our internal control over financial reporting in connection with the occurrence of an error in our estimate of proved oil and natural gas reserves for the year ended December 31, 2008 resulting from the inclusion of uneconomic reserves from properties with negative cash flows. This reserve estimate error resulted in an overstatement of impairment expense, depreciation and amortization expense and income tax benefit on our financial statements for the fiscal year ended December 31, 2008. After fully evaluating the effect of the errors on our December 31, 2008 consolidated financial statements, our management and the audit committee of our Board of Directors concluded that our internal controls over financial reporting were not effective as of December 31, 2008. As a consequence of that determination, we have implemented the procedure discussed below designed to detect or prevent these errors from occurring in the future.

During the fourth quarter of 2009, we implemented a control requiring the Vice President of Business Development and the Senior Vice President of Operations to review our undiscounted future net cash flow ranking one-line summary detail in our reserve reports by lease and by well for all projected properties to insure that those properties with a negative undiscounted cash flow are excluded from the reserve reports. We have discussed this action with our audit committee and believe that such enhanced procedure has mitigated this material weakness.

Except as set forth above, there was no change in our internal control over financial reporting during the quarter ended December 31, 2009 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The effectiveness of our internal control over financial reporting has been audited by UHY LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Larry E. Lee	/s/ G. Les Austin
Larry E. Lee	G. Les Austin
Chairman, President and Chief Executive Officer	Senior Vice President and Chief Financial Officer
March 10, 2010	March 10, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

RAM Energy Resources, Inc.

We have audited RAM Energy Resources, Inc. (a Delaware corporation) and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exist, testing and evaluating the design and operating effectiveness of internal control and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

In our opinion, RAM Energy Resources, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of RAM Energy Resources, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity (deficit), and cash flows for each of the three years in the period ended December 31, 2009, and our report dated March 10, 2010, expressed an unqualified opinion on those consolidated financial statements.

/s/ UHY LLP

Houston, Texas

March 10, 2010

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Item 9B. ***Other Information***

No items to report.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

We have adopted a code of ethics that applies to all directors, officers and employees, including our principal executive officer and principal accounting officer. A copy of our code of ethics is available on our website at *www.ramenergy.com*. We intend to disclose any amendments to or waivers of our code of ethics by posting the required information on our website, *www.ramenergy.com*, or by filing a Form 8-K within the required time periods.

The information required by this item will be set forth in our Definitive Proxy Statement on Schedule 14A relating to our 2010 Annual Meeting, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended, (the Proxy Statement). The Proxy Statement relates to a meeting of stockholders involving the election of directors and the portions therefrom required to be set forth in this Form 10-K by this item are incorporated herein by reference pursuant to General Instruction G(3) to Form 10-K.

Item 11. ***Executive Compensation***

The information required by this item will be set forth in the Proxy Statement. The Proxy Statement relates to a meeting of stockholders involving the election of directors and the portions therefrom required to be set forth in this Form 10-K by this item are incorporated herein by reference pursuant to General Instruction G(3) to Form 10-K.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by this item will be set forth in the Proxy Statement. The Proxy Statement relates to a meeting of stockholders involving the election of directors and the portions therefrom required to be set forth in this Form 10-K by this item are incorporated herein by reference pursuant to General Instruction G(3) to Form 10-K.

Item 13. ***Certain Relationships and Related Transactions and Director Independence***

The information required by this item will be set forth in the Proxy Statement. The Proxy Statement relates to a meeting of stockholders involving the election of directors and the portions therefrom required to be set forth in this Form 10-K by this item are incorporated herein by reference pursuant to General Instruction G(3) to Form 10-K.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item will be set forth in the Proxy Statement. The Proxy Statement relates to a meeting of stockholders involving the election of directors and the portions therefrom required to be set forth in this Form 10-K by this item are incorporated herein by reference pursuant to General Instruction G(3) to Form 10-K.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) (1) The following consolidated financial statements of RAM Energy Resources, Inc. are included in Item 8:

RAM Energy Resources, Inc.

All other schedules have been omitted since the required information is not present, or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or notes thereto.

(a) (3) Exhibits

The following exhibits are filed as a part of this report:

Exhibit	Description	Method of Filing
3.1	Amended and Restated Certificate of Incorporation of the Registrant.	(1) [3.1]
3.2	Amended and Restated Bylaws of the Registrant.	(8) [3.2]
10.1	Form of Registration Rights Agreement among the Registrant and the Initial Stockholders.	(2) [10.9]
10.1.1	Amendment to Registration Rights Agreement among this Registrant and the Founders dated May 8, 2006.	(1) [10.9.1]
10.2	Employment Agreement between Registrant and Larry E. Lee dated May 8, 2006.*	(1) [10.15]
10.2.1	First Amendment to Employment Agreement between Registrant and Larry E. Lee dated October 18, 2006.*	(5) [10.1]
10.2.2	Second Amendment to Employment Agreement of Larry E. Lee dated February 25, 2008.*	(10) [10.6.2]
10.6.3	Third Amendment to Employment Agreement of Larry E. Lee dated December 30, 2008.*	(13) [10.6.3]
10.2.4	Fourth Amendment to Employment Agreement of Larry E. Lee dated March 24, 2009*	(14) [10.6.4]
10.3	Escrow Agreement by and among the Registrant, Larry E. Lee and Continental Stock Transfer & Trust Company dated May 8, 2006.	(1) [10.16]
10.4	Registration Rights Agreement among Registrant and the investors signatory thereto dated May 8, 2006.*	(1) [10.7]
10.5	Form of Registration Rights Agreement among the Registrant and the Investors party thereto.	(3) [10.17]
10.6	Agreement between RAM and Shell Trading-US dated February 1, 2006.	(1) [10.22]

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Exhibit	Description	Method of Filing
10.7	Agreement between RAM and Targa dated January 30, 1998.	(1) [10.23]
10.7.1	Amendment to Agreement between RAM Energy and Targa dated effective as of April 1, 2006, filed as an exhibit to Registrant s Form 8-K dated June 5, 2006 and incorporated by reference herein.	(6) [10.23.1]
10.8	Long-Term Incentive Plan of the Registrant. Included as Annex C of the Registrant s Definitive Proxy Statement (No. 000-50682), dated April 12, 2006 and incorporated by reference herein.*	(4) [Annex C]
10.8.1	First Amendment to the RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 8, 2008.*	(11) [Exhibit A]
10.9	Deferred Bonus Compensation Plan of RAM Energy, Inc. dated as of April 21, 2004.*	(7) [10.14]
10.10	Loan Agreement dated November 29, 2007, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(9) [10.1]
10.10.1	First Amendment to Loan Agreement dated February 6, 2009 by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(15) [10.17.1]
10.10.2	Second Amendment to Loan Agreement dated June 26, 2009, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(16) [10.17.2]
10.11	Description of Compensation Arrangement with G. Les Austin.*	(12) [10.18]
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10.12	Change in Control Separation Benefit Plan of Ram Energy Resources, Inc. and Participating Subsidiaries.	(15) [10.19]
21.1	Subsidiaries of the Registrant.	**
23.1	Consent of UHY LLP.	**
23.2	Consent of Forrest A. Garb & Associates, Inc.	**
31.1	Rule 13(A) 14(A) Certification of our Principal Executive Officer.	**
31.2	Rule 13(A) 14(A) Certification of our Principal Financial Officer.	**
32.1	Section 1350 Certification of our Principal Executive Officer.	**
32.2	Section 1350 Certification of our Principal Financial Officer.	**
99.1	Report of Forrest A. Garb & Associates, Inc.	**

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** Filed herewith.

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(2) Filed as an exhibit to the Registrant s Registration Statement on Form S-1 (SEC File No. 333-113583) as the exhibit number indicated in brackets and incorporated by reference herein.

(3) Filed as an exhibit to the Registrant s Current Report on Form 8-K filed on October 26, 2005, as the exhibit number indicated in brackets and incorporated by reference herein.

(4) Included as an annex to the Registrant s Definitive Proxy Statement (No. 000-50682), dated April 12, 2006, as the annex letter indicated in brackets and incorporated by reference herein.

(5) Filed as an exhibit to the Registrant s Current Report on Form 8-K on October 20, 2006, as the exhibit number indicated in brackets and incorporated by reference herein.

(6) Filed as an exhibit to the Registrant s Current Report on Form 8-K on June 5, 2006, as the exhibit number indicated in brackets and incorporated by reference herein.

(7) Filed as an exhibit to the Registrant s Registration Statement on Form S-1 (SEC File No. 333-138922) as the exhibit number indicated in brackets and incorporated by reference herein.

(8) Filed as an exhibit to the Registrant s Current Report on Form 8-K filed on February 2, 2007, as the exhibit number indicated in brackets and incorporated by reference herein.

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(16) Filed as an exhibit to Registrant s Form 8-K dated July 2, 2009 as the exhibit number indicated in brackets and incorporated by reference herein.

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SIGNATURES

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, in the City of Tulsa, State of Oklahoma, on March 10, 2010.

RAM ENERGY RESOURCES, INC.

By /s/ Larry E. Lee
Larry E. Lee, *Chairman of the Board, President and Chief Executive Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities indicated, on March 10, 2010.

Signature	Title
/s/ Larry E. Lee **Larry E. Lee**	Chairman of the Board, President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ G. Les Austin **G. Les Austin**	Senior Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
/s/ Sean P. Lane **Sean P. Lane**	Director
/s/ Gerald R. Marshall **Gerald R. Marshall**	Director
/s/ John M. Reardon **John M. Reardon**	Director

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INDEX TO EXHIBITS

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