

RAM ENERGY RESOURCES INC
Form 10-K
March 12, 2009
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2008

OR

“ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number: 000-50682

RAM Energy Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of

incorporation or organization)

20-0700684
(I.R.S. Employer Identification

Number)

5100 East Skelly Drive, Suite 650

Tulsa, Oklahoma
(Address of principal

74135
(Zip Code)

executive office)

(918) 663-2800

(Registrant's telephone number, including area code)

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

None

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

Common Stock, \$.0001 par value

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of "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 ☐

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

Yes ☐ No ☒

As of March 11, 2009, there were outstanding 79,668,062 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, 2008, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately \$254.0 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 2009 annual meeting of stockholders, which will be filed with the Securities and Exchange Commission, or SEC, no later than 120 days after December 31, 2008.

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RAM ENERGY RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2008

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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, 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, Oklahoma and West Virginia. 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 million. On November 29, 2007, we acquired Ascent Energy in a cash and stock transaction valued at \$303.8 million. Through December 31, 2008, we have drilled or participated in the drilling of over 700 oil and natural gas wells, over 93% 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 three main onshore locations:

South Texas Starr, Wharton and Duval Counties, Texas;

North Texas Barnett Shale Our Tier 1 Barnett Shale acreage is located in Jack and Wise Counties, Texas, where we own interests in approximately 27,000 gross (7,000 net) acres. Our Tier 2 Barnett Shale acreage is located in Bosque and Hamilton Counties, Texas, where we own interests in approximately 17,000 gross (13,000 net) acres; and

Appalachian Devonian Shale Cabell and Mason Counties, West Virginia. We own leasehold interests in approximately 61,000 gross (50,000 net) acres.

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At December 31, 2008, our estimated net proved reserves were 36.2 MMBoe, of which approximately 40% were crude oil, 47% were natural gas, and 13% were natural gas liquids, or NGLs. The PV-10 Value of our proved reserves was approximately \$311.4 million based on benchmark prices as of December 31, 2008, which were \$44.60 per Bbl of oil and \$5.71 per MMBtu of natural gas. 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, 2008, our proved developed reserves comprised 60% of our total proved reserves.

At December 31, 2008, 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 over 90% of our aggregate PV-10 Value as of December 31, 2008. 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, 2008, we drilled or participated in the drilling of 90 wells on our oil and natural gas properties, 82 of which were successfully completed as producing wells, one of which was a dry hole well and seven of which were either drilling or waiting to be completed at the end of that period. For the twelve months ended December 31, 2008, we generated EBITDA of \$103.6 million from production averaging nearly 7,000 Boe per day. For more information regarding our EBITDA, including a reconciliation to our net income (loss), see Item 6. *Selected Consolidated 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. This year's capital budget of \$40 to \$45 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, 2008, we have identified 195 development and extension drilling projects and 240 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 19 gross (7 net) wells to date with a 100% success rate.

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 acquisition criteria designed to increase reserves, production and cash flow per share on an accretive

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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 28 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 2008, approximately 40% of our estimated proved reserves were oil, 47% were natural gas and 13% 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 over 90% of our aggregate PV-10 Value at December 31, 2008. 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, 2008, we drilled or have participated in the drilling of over 700 oil and natural gas wells with over 93% 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 12, 2009 our directors, executive officers and our two principal stockholders beneficially owned approximately 53% 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 prospectus. 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 and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known 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%.

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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.

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. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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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SAFE HARBOR STATEMENT

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 contained 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 forward-looking 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 some of the more significant factors that could affect our business and our results of operations. We caution the reader that the list of factors may not be exhaustive. Other factors may exist that we cannot anticipate or that we do not consider to be significant based on information that is currently available.

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 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 2008, our average lifting costs were approximately \$18.99 per Boe. 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 continuing 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 2009. However, if oil and natural gas prices continue to decline or remain at reduced 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 as compared to our capital expenditures in 2008 and recent years. A decrease in our capital expenditures will likely result in a decrease in our production levels.

Worldwide demand for oil and natural gas appears to be declining, which could materially reduce our profitability and cash flow.

Based on a number of economic indicators, it appears that growth in global economic activity has slowed substantially. At the present time, the rate at which the global economy will slow has become increasingly uncertain. A slowing of global economic growth, and in particular in the U.S. or China, will likely reduce demand for oil and natural gas, increase spare productive capacity and result in lower oil and natural gas prices, which will reduce our cash flow from operations.

Oil and natural gas prices have declined significantly over the past six months 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 for natural gas. Market prices currently are in the range of \$44.00 for crude oil and \$4.00 for natural gas, a 69% to 73% decline from the earlier highs. As a result, our operating revenues are expected to decline significantly in 2009 as compared with 2008.

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 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.

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Estimates of oil and natural gas reserves are uncertain and may vary substantially from actual production.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures, including many factors beyond our control. Petroleum engineering is not an exact science. Information relating to our proved oil and natural gas reserves is based upon engineering estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

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 current deterioration 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.

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 \$16.2 million, \$16.0 million of which is restricted, as of December 31, 2008. 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

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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.

We have been a defendant in a class action lawsuit alleging the underpayment of oil and natural gas royalties in the past. If we were again sued for royalty underpayments and ultimately determined to be liable, the amount of the judgment could adversely affect our financial condition.

Several of our subsidiaries have been named defendants in a class action lawsuit in which the plaintiffs seek monetary damages for our alleged underpayment of oil and natural gas royalties, including damages for alleged breach of contract, alleged tortious breach of implied covenants and alleged breach of fiduciary duty, together with punitive damages and other equitable relief. Lawsuits of this nature are not uncommon in the oil and natural gas production industry. If we are sued again in a similar lawsuit and the amount of any damages ultimately awarded to the plaintiffs were material, it could adversely affect our financial condition. For a further discussion of settled litigation of this type, please see Item 3. *Legal Proceedings* appearing elsewhere in this report.

Our operations are subject to various governmental regulations that require compliance that can be burdensome and expensive. Proposed changes in tax laws affecting the oil and gas industry may adversely affect our financial condition and results of operations.

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. Also, the new administration recently proposed certain changes to the federal income tax laws that could, if adopted, adversely affect our financial condition and results of operations, including a requirement to capitalize rather than expense intangible drilling costs, repeal of percentage depletion and a provision lengthening the period for amortization of geological and geophysical expenses. We cannot predict what, if any, other changes in the laws affecting our industry may be proposed by the new administration or adopted by Congress.

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

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any reporting date, such excess costs are charged to operations. In the current year, we recorded a \$282.0 million charge for the impairment of our oil and natural gas properties. This writedown is 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;

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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.

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

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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 continuing decline in oil and natural gas prices, or a prolonged period of oil and natural gas prices at current 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.

Risk Related to Our Common Stock

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

Prior to consummation of our RAM Energy acquisition, RAM Energy regularly paid cash dividends to its stockholders. 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.

Voting control 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 19% of our outstanding common stock. In addition, persons who beneficially own approximately 30% of our outstanding common stock are subject to a voting agreement pursuant to which such holders agree to vote for the slate of directors proposed by our board of directors through our 2009 annual meeting of stockholders. Accordingly, our insiders and the parties to this voting agreement will be able to control the election of directors and, therefore, our policies and direction during the term of the voting agreements. 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 one hundred million shares of common stock and one million shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As of December 31, 2008, we had outstanding 78,532,134 shares of common stock, and outstanding options to purchase 275,000 shares of our common stock at an exercise price of \$9.90 per share. In addition, we have reserved an additional 3,734,526 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

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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.

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 certificate of incorporation also provides that our bylaws may be amended by the affirmative vote of the holders of at least 80% of the voting power of the outstanding shares of our capital stock.

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.

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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.

BUSINESS AND PROPERTIES**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 2008, we participated in the drilling of 90 gross wells (72.1 net) in these areas and experienced a success rate of 99%.

The following table summarizes our estimated proved oil and gas reserves by area as of December 31, 2008 and our average daily production by area for calendar year 2008.

	Average Daily Production Boe	Oil MBbls	Gas MMcf	NGL MBbls	Equivalent MBoe	Percent of proved reserve
Developing Fields	2,170	551	50,006	3,008	11,893	33%
Mature Oil Fields	3,375	12,101	7,904	415	13,834	38%
Mature Gas Fields	1,452	1,844	44,602	1,192	10,469	29%
	6,997	14,496	102,512	4,615	36,196	100%

Developing Fields

The average daily production from our developing fields averaged 2,170 Boe per day (31.0% of the company total daily production) in 2008. We drilled a total of 23.0 gross wells (17.0 net) in 2008 and completed 100% as producers. Our drilling activity targeted the Vicksburg sands in South Texas, the Barnett Shale in North Texas, and the Devonian Shale in West Virginia. As of December 31, 2008, the proved reserves in our developing fields are 11.9 million Boe and account for 33% of our total proved reserves. The most significant fields within the developing fields group are noted as follows.

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South Texas. During 2008, our net daily production from our South Texas properties averaged 1,625 Boe per day. We participated in drilling 3.0 gross wells (3.0 net) in our La Copita field in Star County, Texas and 2.0 gross well (2.0 net) in the West Lissie field in Wharton County, TX. All completions were successful and flowing gas at initial daily rates ranging from 250 Boe per day to over 500 Boe per day from the Vicksburg formation in Star County and over 67 Boe per day from the Wilcox formation in Wharton County, Texas. Our 2008 drilling program in the La Copita field added another 14 new proved undeveloped locations to our drilling inventory. The South Texas properties make up 27% (9.7 million Boe) of our total proved reserves and 82% of our reserves in our developing fields category. We operate 100% of these wells. We plan to drill 4.0 gross (3.5 net) Vicksburg wells in 2009 and 1.0 gross (1.0 net) Wilcox well in 2009.

Barnett Shale Jack and Wise Counties Texas. We participated in drilling 7.0 gross wells (3.2 net) in 2008 on our Tier 1 Barnett Shale acreage in Wise and Jack Counties in the Fort Worth Basin of North Texas. All of these Barnett Shale wells were completed as producers for a 100% success rate. The average 2008 net daily production rate was 515 Boe per day (approximately 7% of our company's 2008 average daily production). 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 19.0 gross wells (7.0 net) have been drilled since the inception of the agreement. As of December 31, 2008 we estimated our proved reserves in our Tier 1 Barnett Shale area to be 2.6 million Boe, or 6% of our proved reserves.

Mature Oil Fields

We produced an average of 3,375 Boe per day from our mature oil fields during 2008. Proved reserves as of December 31, 2008 were 13.8 million Boe (38% of our total reserve base). Our mature oil fields are shallow oil fields that have historically exhibited very dependable production performance and have sizable long life reserves.

Northeast Fitts and Allen Field. During 2008, we participated in the drilling of 8.0 gross (7.2 net) infill wells in Pontotoc and Seminole Counties, Oklahoma. The North East Fitts field produces from shallow McAlester and Hunton formations at depths less than 4,250 feet. We are the operator of the units with approximately a 91% working interest. The North East Fitts field was waterflooded over time and we are evaluating the potential of re-establishing a more efficient injection profile to improve field production rates and ultimate recovery. The combined proved reserves from these two areas are 8.0 million Boe (22% of our proved reserves).

Electra/Burkburnett Fields. We drilled a total of 42.0 gross (42.0 net) wells during 2008 in Wichita and Wilbarger Counties, Texas and we have drilled more than 250 wells in these fields since November 1, 2004. We are planning on drilling another 45.0 gross (45.0 net) wells in 2009 and have a large inventory of more than 100 drilling locations. 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 keying on low cost investment opportunities to achieve improved production performance such as recompletions, workovers, and improving water injection performance. As of December 31, 2008, the estimated proved reserves in these fields are 5.2 million Boe (14% of our total proved reserves).

Mature Gas Fields

We participated in drilling 14.0 gross (2.9 net) wells in our mature gas fields in 2008. The average daily production was 1,452 Boe per day during 2008, and the proved reserves are 10.4 million Boe (29% of the company's total proved reserves). The proved reserves in our Boonsville field in Jack and Wise Counties, TX are estimated at 2.0 million Boe (6% of the total proved reserves). We also have production in the Lake Enfermer

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field in Lafourche Parish, Louisiana. Our Louisiana reserves total 3.6 million Boe (10 % of our total proved reserves). Multiple recompletions are budgeted in the immediate future as we attempt to improve production.

The following table summarizes our 2008 drilling activity:

	Gross wells Drilled	Developed Net Wells Drilled	Completion Rate (%)	Gross wells Drilled	Exploratory Net Wells Drilled	Completion Rate (%)
Developing Fields	17.0	11.9	100	6.0	5.1	100
Mature Oil Fields	53.0	52.2	100			
Mature Gas Fields	14.0	2.9	93			
	84.0	67.0	99	6.0	5.1	100

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, 706 injection wells. During the year ended December 31, 2008, we drilled or participated in the drilling of 84.0 gross (67.0 net) development wells on our oil and gas properties. Capital expenditures in connection with these activities during this period aggregated approximately \$57.1 million.

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 240 projects involving recompletions in existing wells, all of which involve reserves included in our proved reserves at December 31, 2008.

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 2009, assuming the continuation of existing commodity prices for oil and natural gas, we expect to conduct only limited exploration activities. In our core areas, we own in excess of 200,000 gross (75,000 net) undeveloped leasehold acres (including options), which enhances our competitive exploration position and provides the foundation for future reserve additions.

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, 2008, we drilled or participated in the drilling of 6.0 gross (5.1 net) exploratory wells at a cost of approximately \$10.5 million and incurred total capital expenditures of approximately \$14.9 million for all exploration activities. At December 31, 2008, 2.0 gross (1.0 net) exploratory wells were awaiting completion and zero wells were dry holes. For 2009, we have budgeted \$5.0 million for geological and geophysical activities relating to exploration projects and \$5.0 million for leasehold acquisition for exploratory drilling.

Table of Contents**Oil and Natural Gas Reserves**

At December 31, 2008, our estimated net proved reserves were 36.2 million Boe, of which 40% were crude oil, 47% were natural gas, and 13% were NGLs, with a PV-10 Value of approximately \$311.4 million before income taxes. Our estimated proved developed reserves comprised 60% of our total proved reserves, and our reserve life for total proved reserves is approximately 14.5 years.

The following table summarizes the estimates of our historical net proved reserves and the related present values of such reserves at the dates shown. The reserve and present value data for our oil and natural gas properties as of December 31, 2008 was prepared by the independent petroleum engineering firms of Williamson Petroleum Consultants, Inc. and Forrest A. Garb & Associates.

Estimated quantities of proved reserves and future net revenues therefrom 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.

	As of December 31,		
	2008	2007	2006
Reserve Data:			
Proved developed reserves:			
Oil (MBbls)	9,235	13,552	6,954
Natural gas (MMcf)	59,717	50,990	26,888
Natural gas liquids (MBbls)	2,710	2,565	1,671
Total (MBoe)	21,897	24,615	13,106
PV-10 Value (in thousands)	\$ 228,568	\$ 593,300	\$ 192,045

	As of December 31,		
	2008	2007	2006
Proved reserves:			
Oil (MBbls)	14,496	19,544	10,796
Natural gas (MMcf)	102,512	93,358	33,199
Natural gas liquids (MBbls)	4,615	4,271	2,123
Total (MBoe)	36,196	39,375	18,452
PV-10 Value (in thousands)	\$ 311,385	\$ 911,549	\$ 269,892
Prices used in calculating PV-10 Value:			
\$/Bbl (Oil)	\$ 44.15	\$ 93.90	\$ 58.74
\$/Mcf	\$ 5.33	\$ 7.00	\$ 5.51
\$/Bbl (NGL)	\$ 23.59	\$ 54.69	\$ 36.51

The following is a summary of the standardized measure of discounted net cash flows using methodology provided for in Statement of Financial Accounting Standard No. 69, related to our estimated proved oil and

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natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves were computed using 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, 2008, 2007 and 2006, please review Note M in the notes to our year-end 2008 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,		
	2008	2007 (in thousands)	2006
Future cash inflows	\$ 1,294,803	\$ 2,722,099	\$ 894,626
Future production costs	(482,977)	(824,576)	(356,961)
Future development costs	(188,415)	(146,734)	(48,605)
Future income tax expenses	(99,862)	(574,169)	(158,602)
Future net cash flows	523,549	1,176,620	330,458
10% annual discount for estimated timing of cash flows	(248,300)	(578,225)	(150,717)
Standardized measure of discounted future net cash flows	\$ 275,249	\$ 598,395	\$ 179,741

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, and is calculated in accordance with SFAS No. 69. The following table provides a reconciliation of our PV-10 Value to our standardized measure:

	2008	At December 31, 2007 (in thousands)	2006
PV-10 Value	\$ 311,385	\$ 911,549	\$ 269,892
Future income taxes	(99,862)	(594,169)	(158,602)
Discount of future income taxes at 10% per annum	63,726	261,015	68,451
Standardized Measure	\$ 275,249	\$ 598,395	\$ 179,741

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.

Table of Contents**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,		
	2008	2007 (1)	2006
Production volumes:			
Oil (MBbls)	1,187	774	752
Natural gas liquids (MBbls)	354	184	143
Natural gas (MMcf)	6,082	2,785	2,365
Total (MBoe)	2,554	1,422	1,290
Average realized prices (before effects of derivative contracts):			
Oil (per Bbl)	\$ 98.59	\$ 71.11	\$ 63.82
Natural gas liquids (per Bbl)	50.24	49.16	40.33
Natural gas (per Mcf)	7.87	6.40	6.02
Total per Boe	71.52	57.60	52.74
Effect of settlement of derivative contracts:			
Oil (per Bbl)	\$ (8.84)	\$ (4.35)	\$ (5.78)
Natural gas liquids (per Bbl)			
Natural gas (per Mcf)		.25	(.13)
Total per Boe	(4.10)	(1.88)	(3.61)
Average realized prices (after effects of derivative contracts):			
Oil (per Bbl)	\$ 89.75	\$ 66.77	\$ 58.04
Natural gas liquids (per Bbl)	50.24	49.16	40.33
Natural gas (Per Mcf)	7.87	6.65	5.89
Total per Boe	67.42	55.72	49.13
Expenses (per Boe):			
Oil and natural gas production taxes	\$ 4.10	\$ 3.43	\$ 2.58
Oil and natural gas production expenses	14.89	15.18	14.16
Amortization of full cost pool	17.99	12.86	9.77
General and administrative	7.95	8.36	7.21
Impairment	110.58		

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

Table of Contents**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,		
	2008	2007 (1)	2006
Proved property acquisition costs	\$ 10,091	\$ 299,573	\$ 4,476
Unproved property acquisition costs	2,691	24,642	705
Development costs	57,084	12,921	18,475
Exploration costs	14,857	7,659	4,489
Total costs incurred	\$ 84,723	\$ 344,795	\$ 28,145

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

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,		
	2008	2007 (1)	2006
Proved reserves acquired/discovered (MBoe)	5,180	19,973	2,973
Total cost per Boe of reserves acquired/discovered	\$16.36	\$17.26	\$9.47

(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, 2008. 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	2,749	2,101
Natural gas	654	353
Total	3,403	2,454

Acreage

The following table sets forth our developed and undeveloped gross and net leasehold acreage, including options to acquire leasehold acreage, as of December 31, 2008:

	Gross	Net
Developed	152,383	73,465
Undeveloped	261,368	107,323
Total	413,751	180,788

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Approximately 75% of our net acreage was located in our core areas as of December 31, 2008. 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.

Drilling Activities

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

	Year Ended December 31,					
	2008 (1)		2007 (2)		2006 (3)	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	83	66.8	52	52.0	77	75.7
Non-productive	1	0.2	5	5.0	2	.5
Exploratory wells:						
Productive	6	5.1	11	2.0	3	.7
Non-productive			2	.4	2	1.5
Total	90	72.1	70	59.4	84	78.4

- (1) Does not include 7.0 gross (5.8 net) wells that were in the process of being completed at December 31, 2008.
- (2) Does not include 11.0 gross (9.0 net) wells that were in the process of being completed at December 31, 2007.
- (3) Does not include 3.0 gross (2.1 net) wells that were in the process of being completed at December 31, 2006.

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 million Boe 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, 2008, Shell Trading (US) Company, or STUSCO, accounted for \$97.4 million, or 53%, 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 2008. Our agreement with STUSCO, which covers all of our north Texas oil production through December 31, 2008, 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 refinery demand), minus \$1.50.

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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, 2008.

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 also lease a small office in Houston, Texas. We believe that our facilities are adequate for our current needs.

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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.

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.

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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, 2008, we had 202 employees, of whom 41 were administrative, accounting or financial personnel and of whom 161 were technical and operations personnel. Our exploration staff includes 3 exploration geologists and 6 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). RAM Energy, together with certain of its subsidiaries and affiliates, are defendants in this lawsuit, which is a putative class action case filed by a landowner alleging 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. The plaintiff filed the lawsuit

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as a class action on behalf of himself and all other royalty owners under leases held by any of the defendants upon which wells were connected to the system. Plaintiff seeks unspecified damages for breach of contract, tortious breach of implied covenants and breach of fiduciary duty, together with an accounting, imposition of a constructive trust, a permanent injunction, punitive damages and recovery of litigation costs and fees. We believe that a fair and proper accounting was made to the royalty owners for production from the affected leases.

On January 11, 2007, the Court entered an order certifying the plaintiff's proposed class. 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 October 14, 2008, the trial court preliminarily approved the settlement and scheduled a fairness hearing. Following that preliminary approval, the entire settlement amount was deposited in escrow by the defendants pending final approval of the settlement. 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. Absent the filing of an appeal, which is unlikely as there were no objections to the settlement, the judgment will become final on April 4, 2009, promptly after which the plan of distribution will be 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. These escrowed shares will remain in escrow until the litigation is resolved. At such time as the litigation is finally resolved, the former stockholders of RAM Energy have 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.

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. Judgment has not yet been entered in the case, but is expected to be in the range of \$3.2 million. We plan to appeal the judgment, when entered, to the United States Court of Appeals for the Fifth Circuit.

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 incurred by us 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. The balance in the escrow account is sufficient to satisfy the former Ascent owners' indemnification obligation with respect to this lawsuit. During the fourth quarter of 2008, the Company recorded a contingent liability of \$0.9 million related to this litigation.

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

None.

Table of Contents**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
2009:		
First Quarter (through March 11, 2009)	\$ 1.24	\$ 0.40
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
2006:		
First Quarter	\$ 5.89	\$ 5.46
Second Quarter	6.79	5.19
Third Quarter	5.79	4.68
Fourth Quarter	5.64	4.65

Holders

As of March 4, 2009, there were 82 holders of record of our common stock. We believe that at March 4, 2009, there were 6,387 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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The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2008, 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)	1,468,244(2)	\$ 4.79(3)	3,734,526(4)
Equity compensation plans not approved by security holders			
Total	1,468,244	\$ 4.79	3,734,526

- (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, 2008.
- (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, 2008.

Table of Contents**Stockholder Return Performance Presentation**

The following graph and table compare the cumulative 55-month total return provided to our stockholders on our common stock beginning May 24, 2004 (the date of consummation of our initial public offering) through December 31, 2008, 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 May 24, 2004 and in each of the indexes and its relative performance is tracked through December 31, 2008. 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,				
	2008	2007	2006	2005	2004
RAM Energy Resources, Inc.	\$ 19	\$ 107	\$ 117	\$ 117	\$ 108
Nasdaq Composite	83	142	129	116	113
Dow Jones Wilshire MicroCap Exploration & Production Index	48	133	194	164	123

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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 2008, 2007 and 2006 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.

Table of Contents**Selected Financial Data**

(in thousands, except share data)

	Year Ended December 31,				
	2008	2007 (1)	2006	2005	2004 (2)
Revenues and Other Operating Income:					
Oil sales	\$ 117,036	\$ 55,000	\$ 48,013	\$ 42,322	\$ 6,698
Natural gas sales	47,884	17,830	14,232	17,728	307
Natural gas liquids sales	17,770	9,047	5,770	6,193	10,970
Realized losses on derivatives	(10,472)	(2,669)	(4,650)	(5,393)	(870)
Unrealized gains (losses) on derivatives	33,257	(10,056)	6,239	(6,302)	77
Gain on sale of subsidiary					12,139
Gain on sale assets	10	61	142		
Other	372	427	498	851	338
Total revenues and other operating income	205,857	69,640	70,244	55,399	29,659
Operating Expenses:					
Oil and natural gas production taxes	10,480	4,869	3,329	3,320	1,263
Oil and natural gas production expenses	38,030	21,574	18,266	16,099	3,600
Depreciation and amortization	46,758	18,948	13,252	12,972	3,273
Accretion expense	2,207	704	535	510	78
Impairment	282,465				
Share-based compensation	2,563	989	2,308		
General and administrative, net of operator's overhead fees	20,305	11,891	9,300	8,610	6,601
Total operating expenses	402,808	58,975	46,990	41,511	14,815
Operating income (loss)	(196,951)	10,665	23,254	13,888	14,844
Other Income (Expense):					
Interest expense	(24,182)	(20,757)	(17,050)	(12,614)	(5,070)
Interest income	208	1,047	309	75	35
Other expense	(13,536)	(57)			
Income (Loss) Before Income Taxes	(234,461)	(9,102)	6,513	1,349	9,809
Income Tax Provision (Benefit)	(96,389)	(7,852)	1,465	806	3,733
Net income (loss)	\$ (138,072)	\$ (1,250)	\$ 5,048	\$ 543	\$ 6,076

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

(2) We acquired WG Energy Holdings, Inc. in December 2004.

Table of Contents**Selected Financial Data (continued)**

(in thousands, except share data)

	Year Ended December 31,				
	2008	2007 (1)	2006	2005	2004 (2)
Net income (loss) per share attributable to common stockholders basic	\$ (1.95)	\$ (0.03)	\$ 0.16	\$ 0.02	\$ 0.20
Cash dividends per share	\$	\$	\$ 0.02	\$ 0.05	\$ 0.04
Earnings (loss) per share:					
Basic	\$ (1.95)	\$ (0.03)	\$ 0.16	\$ 0.02	\$ 0.20
Diluted	(1.95)	(0.03)	0.16	0.02	0.20
Weighted average shares outstanding:					
Basic	70,629,452	41,240,021	30,808,065	26,492,286	29,706,104
Diluted	70,629,452	41,240,021	32,105,885	26,492,286	29,706,104

Statement of Cash Flow Data

Cash provided by (used in):

Operating activities	\$ 74,454	\$ 17,042	\$ 29,660	\$ 18,359	\$ 1,793
Investing activities	(82,568)	(241,192)	(25,317)	(12,554)	(64,852)
Financing activities	1,405	224,302	2,308	(6,910)	62,116

Other Data

Capital expenditures (3)	\$ 84,723	\$ 344,795	\$ 28,145	\$ 13,528	\$ 102,719
EBITDA	103,641	42,352	33,419	33,747	\$ 18,153

	As of December 31,				
	2008	2007 (1)	2006	2005	2004 (2)
Balance Sheet Data					
Total assets	\$ 395,845	\$ 580,242	\$ 161,725	\$ 143,276	\$ 140,324
Long-term debt, including current portion	250,696	335,747	132,237	112,846	117,344
Stockholders equity (deficit)	49,721	98,698	(27,895)	(20,769)	(19,912)

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

(2) We acquired WG Energy Holdings, Inc. in December 2004.

(3) Includes costs of acquisitions.

Our 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 EBITDA to net income (loss).

We present EBITDA because we believe that it provides useful information regarding our continuing operating results. We rely on 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 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. 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, EBITDA should neither be considered as a measure of discretionary cash available to us to invest in

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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 EBITDA as supplemental information.

	2008	Year ended December 31, 2007 2006 2005			2004
		(in thousands)			
Reconciliation of EBITDA to net income (loss):					
Net income (loss)	\$ (138,072)	\$ (1,250)	\$ 5,048	\$ 543	\$ 6,076
Plus: Interest expense	24,182	20,757	17,050	12,614	5,070
Plus: Amortization and depreciation expense	46,758	18,948	13,252	12,972	3,273
Plus: Accretion expense	2,207	704	535	510	78
Plus: Income tax expense (benefit)	(96,389)	(7,852)	1,465	806	3,733
Plus: Share-based compensation	2,563	989	2,308		
Plus: Impairment charges	282,465				
Plus: Settlement charge	13,184				
Plus: Unrealized (gain) loss on derivatives	(33,257)	10,056	(6,239)	6,302	(77)
EBITDA	\$ 103,641	\$ 42,352	\$ 33,419	\$ 33,747	\$ 18,153

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, Oklahoma and West Virginia. Through our RAM Energy subsidiary, we have been active in our core producing areas of Texas, Oklahoma and Louisiana 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, which we refer to as the merger agreement, 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.

Upon consummation of the RAM Energy acquisition, the stockholders of RAM Energy received an aggregate of 25,600,000 shares of our common stock and \$30.0 million of cash. Prior to consummation of the RAM Energy acquisition, and as permitted by the merger agreement, on April 6, 2006, RAM Energy redeemed a portion of its outstanding stock for an aggregate consideration of \$10.0 million.

The RAM Energy acquisition was accounted for as a reverse acquisition. RAM Energy has been 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

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\$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.

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 2008, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were \$98.59 per Bbl and \$7.87 per Mcf compared with 2007 average realized prices of \$71.11 per Bbl and \$6.40 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 Mmbtu on December 31, 2008 from \$12.27 per Mmbtu 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 have 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. 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 are closely monitoring 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 in effect at the time of the calculation are held constant.

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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 oil and natural gas properties exceeded the Ceiling Limitation resulting in reduction in the carrying value of our oil and natural gas properties by \$282.0 million, \$179.6 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. The effective date of the new accounting and disclosure requirements is for annual reports filed for fiscal years ending on or after December 31, 2009. Companies are 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.

We are currently evaluating the effect the adoption of the final rule will have on our financial statements and oil and natural gas reserve estimates and disclosures.

Statement of Financial Accounting Standards No. 143 (SFAS No. 143), *Accounting for Asset Retirement Obligations*, 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 (SFAS No. 19), *Financial Accounting and Reporting by Oil and Gas Producing Companies*. SFAS No. 143 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.

Under Statement of Financial Accounting Standards No. 109 (SFAS No. 109), *Accounting for Income Taxes*, deferred income taxes are recognized at each year 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

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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 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 under Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instrument and Hedging Activities* (SFAS 133). SFAS 133 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 as earnings. We have not elected to designate our derivative instruments as hedges as required by SFAS 133 in order to receive hedge accounting treatment. Accordingly, all gains and losses on the derivative instrument have been recorded in earnings.

We account for share-based payments under Statement of Financial Accounting Standards No. 123R, *Share-Based Payments* (SFAS 123R). SFAS 123R 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.

Effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). The Interpretation 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 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, 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.

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

	South Texas	Developing Fields Barnett Shale	Appalachia	Mature Oil Fields* Various	Mature Natural Gas Fields 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,		Increase
	2008	2007	
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.

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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.

Amortization and Depreciation Expense. Our amortization and depreciation expense increased \$27.8 million, or 147%, 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 \$46.0 million was \$17.99 per Boe for the year ended December 31, 2008, an increase per Boe of 40% 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. SFAS No. 143, Accounting for Asset Retirement Obligations, includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value 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 \$282.0 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.

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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 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.

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 \$96.4 million, on a pre-tax loss of \$234.5 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 38.2% for the year ended December 31, 2008 and 36.3% for the year ended December 31, 2007.

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Oil and natural gas sales increased \$13.9 million, or 20% to \$81.9 million for the year ended December 31, 2007 as compared to \$68.0 million for the year ended December 31, 2006. This increase was driven by both commodity price increases, which increased 9% for the year ended December 31, 2007 as compared to 2006, and by volume increases which increased 10% for the year ended December 31, 2007 as compared to 2006.

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The following table summarizes our oil and natural gas production volumes, average sales prices and period to period comparisons for the years ended December 31, 2007 and 2006 (in thousands):

	Developing Fields		Mature Oil Fields*	Mature Natural Gas Fields	
	South Texas	Barnett Shale	Various	Various	Total
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
Year Ended December 31, 2006					
Aggregate Net Production					
Oil (MBbls)		5	651	96	752
NGLs (MBbls)		5	49	89	143
Natural Gas (MMcf)		374	206	1,785	2,365
MBoe		72	734	484	1,290
Change in MBoe	44	55	104	(71)	132
Percentage Change in MBoe	0.0%	76.4%	14.2%	(14.7%)	10.2%

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

	Year ended December 31,		Increase
	2007	2006	
Average sale prices:			
Oil (per Bbl)	\$ 71.11	\$ 63.82	11.4%
NGL (per Bbl)	\$ 49.16	\$ 40.33	21.9%
Natural gas (per Mcf)	\$ 6.40	\$ 6.02	6.4%
Per Boe	\$ 57.60	\$ 52.74	9.2%

Production volumes increased 10% during the year ended December 31, 2007 primarily due to the Ascent acquisition in November 2007, and the 57.0 gross development and 13.0 gross exploratory wells drilled during the year ended December 31, 2007. Production from our developing fields of Barnett Shale increased by 55 MBoe in the current year and accounted for 42% of our total production growth as compared with the year ended December 31, 2006. Drilling activity included 4.0 gross additional Barnett Shale development wells. Production from our mature oil fields of Electra/Burkburnett in North Texas and Allen/Fitts in Pontotoc County, Oklahoma increased by 104 MBoe over the prior year. Drilling activity included 53.0 gross development wells in Electra/Burkburnett.

The average realized sales price for oil was \$71.11 per barrel for the year ended December 31, 2007, an increase of 11%, compared to \$63.82 per barrel for the same period in 2006. The average realized sales price for NGLs was \$49.16 for the year ended December 31, 2007, an increase of 22%, compared to \$40.33 per barrel for the same period in 2006. The average realized sales price for natural gas was \$6.40 per Mcf for the year ended December 31, 2007, an increase of 6%, compared to \$6.02 per Mcf for the same period in 2006.

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Realized and Unrealized Gain (Loss) from Derivatives. For the year ended December 31, 2007, our loss from derivatives was \$12.7 million, compared to a gain of \$1.6 million for the previous year. Our gains and losses during these periods were the net result of recording actual contract settlements, the premium costs paid for various derivative contracts, and unrealized mark-to-market values of our derivative contracts as of each year end.

	Year ended December 31,	
	2007	2006
Contract settlements and premium costs:		
Oil	\$ (3,362)	\$ (4,349)
Natural gas	693	(301)
Realized (losses)	(2,669)	(4,650)
Mark-to-market gains (losses):		
Oil	(9,689)	1,686
Natural gas	(367)	4,553
Unrealized gains (losses)	(10,056)	6,239
Realized and unrealized gains (losses)	\$ (12,725)	\$ 1,589

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were \$4.9 million for the year ended December 31, 2007, compared to \$3.3 million for the year ended December 31, 2006. Production taxes are based on realized prices at the wellhead or volumes of production. As revenues or production volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 6.0% for the year ended December 31, 2007, compared to 4.9% for the year ended December 31, 2006.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense was \$21.6 million for the year ended December 31, 2007, an increase of \$3.3 million, or 18%, from the \$18.3 million for the previous year. Ascent reported \$1.4 million of production expense for the last month of 2007. For the year ended December 31, 2007, our oil and natural gas production expense was \$15.18 per Boe compared to \$14.16 per Boe for the year ended December 31, 2006, an increase of 7%. As a percentage of oil and natural gas sales, oil and natural gas production expense decreased slightly to 26% for the year ended December 31, 2007, down from 27% in the year ended December 31, 2006.

Amortization and Depreciation Expense. Our amortization and depreciation expense increased \$5.7 million, or 43%, for the year ended December 31, 2007, compared to the year ended December 31, 2006. The increase was primarily a result of our Ascent acquisition in late November 2007, which represented \$2.8 million amortization and depreciation expense for the last month of the year. Also contributing to the increase was higher capitalized costs due to increased drilling in the last half of 2007. On an equivalent basis, our amortization of the full-cost pool of \$18.3 million was \$12.86 per Boe for the year ended December 31, 2007, an increase per Boe of 32% compared to \$12.6 million, or \$9.77 per Boe for the year ended December 31, 2006.

Accretion Expense. SFAS No. 143, Accounting for Asset Retirement Obligations, includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period. We recorded \$0.7 million for the year ended December 31, 2007, compared to \$0.5 million for the year 2006.

Share-Based Compensation. Our Board of Directors awarded grants in accordance with our 2006 Long-Term Incentive Plan. The share-based compensation on these grants was calculated using the closing price per share on each of the grant dates. The total share-based compensation on all these grants will be recognized over vesting periods ranging from one month to five years. For the year ended December 31, 2007, we recognized a total of \$1.0 million share-based compensation on these grants, compared to \$2.3 million recognized in 2006.

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General and Administrative Expense. For the year ended December 31, 2007, our general and administrative expense was \$11.9 million, compared to \$9.3 million for the year ended December 31, 2006, an increase of \$2.6 million, or 28%. The acquisition of Ascent in late November 2007 represented \$0.5 million of this increase. The remainder of the increase was due to higher salaries resulting from a larger employee base and increased salaries.

Interest Income. Interest income was \$1.0 million for the year ended December 31, 2007 compared to \$0.3 million for the year ended December 31, 2006. The increase was due to higher cash balances resulting from proceeds held from the common stock offering which closed in February of 2007. Cash balances remained high through November 2007, when we utilized the cash in the Ascent acquisition.

Interest Expense. Our interest expense increased by \$3.7 million, to \$20.8 million for the year ended December 31, 2007, compared to \$17.1 million incurred for the previous year. As a result of refinancing, the write-off of unamortized loan costs made up \$2.4 million interest expense in 2007 compared to \$2.1 million of unamortized loan costs and prepayment premiums written off in 2006. The overall increased expense is due to additional borrowings on the revolving credit facility during the 2007 period.

Income Taxes. For the year ended December 31, 2007, we recorded an income tax benefit of \$3.3 million on a pre-tax loss of \$9.1 million. We also reduced income tax expense by \$4.6 million in the third quarter of 2007 to reverse an uncertain tax position and related accrued interest as a result of the expiration of the applicable statute of limitations period. For the year ended December 31, 2006, our income tax expense was \$1.5 million, on a pre-tax income of \$6.5 million. Excluding the reversal of the uncertain tax positions, the effective tax rate was 36% for the year ended December 31, 2007 and 22% for 2006.

Liquidity and Capital Resources

As of December 31, 2008, we had cash and cash equivalents of \$0.2 million and \$37.7 million was available under our revolving credit facility. At that date, we had \$250.7 million of indebtedness outstanding, including \$250.4 million under our credit facility, and \$0.3 million in other indebtedness. In addition, we had \$0.3 million utilized by outstanding letters of credit. As of December 31, 2008, we had an accumulated deficit of \$167.1 million and a working capital deficit of \$3.0 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 will bear interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. At December 31, 2008, the balance outstanding under our revolving credit facility was \$137.0 million. The term loan portion of our credit facility provides for payments of interest only during its five-year term, with the interest rate being LIBOR plus 7.5%. 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 the existing level of \$113.4 million. During 2008, we reduced the outstanding balance of our credit facility by a net of \$56.0 million.

Advances under the new facility are secured by liens on substantially all of our properties and assets. The loan agreement 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

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and a required ratio of asset value to total indebtedness. 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 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, 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.

At December 31, 2008, we were in compliance with all of the financial covenants under our loan agreement; however, a continuing decline in oil and natural gas prices, or a prolonged period of oil and natural gas prices at current levels, could eventually result in our failing to meet certain 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, 2008, our commodity hedging represented approximately 51% of our projected production volumes through June 30, 2011.

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, 2008, our net loss was \$138.1 million, as compared to a net loss of \$1.3 million for the year ended December 31, 2007. 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 \$218.4 million for the year ended December 31, 2008 compared to \$24.9 million for the year of 2007, an increase of \$193.5 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 increase. Working capital changes for the year ended December 31, 2008 were a negative \$5.9 million compared with negative changes of \$6.6 million for the year ended December 31, 2007. For the year ended December 31, 2008, in total, net cash provided by operating activities was \$74.5 million compared to \$17.0 million of net cash provided by operations for the previous year.

Cash Flow From Investing Activities. For the year ended December 31, 2008 net cash used in our investing activities consisted of \$86.0 million in payments for oil and gas properties and other equipment, offset by \$3.0 million in proceeds from sales of property and equipment and \$0.4 million from the sale of a gathering system and other investments. For the year ended December 31, 2008, net cash used in our investing activities was \$82.6 million; a 66% decrease compared to the previous year.

Cash Flow From Financing Activities. For the year ended December 31, 2008, net cash provided by our financing activities was \$1.4 million, compared to net cash provided of \$224.3 million for the year ended December 31, 2007. 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. The cash provided in 2007 included \$199.5 million in proceeds from borrowing on long-term debt in connection with the Ascent acquisition, and \$27.4 million in net proceeds from a common stock offering, partially offset by a \$2.4 million net debt decrease and \$0.2 million for the repurchase of stock.

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Capital Commitments

During 2008, we had capital expenditures of \$84.7 million relating to our oil and natural gas operations, of which \$57.1 million was allocated to drilling new development wells and recompletion operations in existing wells, \$14.9 million was for exploration costs, and \$12.7 million was for acquisition costs.

We have budgeted \$40.0-\$45.0 million for non-acquisition capital expenditures in 2009 related to:

geological, geophysical and seismic costs (\$5.0 million);

developmental drilling and recompletions (\$30.0-\$35.0 million); and

exploratory drilling, including leasehold acquisitions (\$5.0 million).

In our 2009 non-acquisition capital budget, we have allocated \$12.0-\$14.0 million for drilling on our South Texas properties, \$1.0-\$2.0 million for our North Texas Barnett Shale, \$8.0-\$9.0 million for continued development of our Electra/Burkburnett area, \$8.0-\$9.0 for reworking and production enhancement operations in our Louisiana mature gas fields, and \$1.0 million to our Pontotoc properties in Oklahoma.

The amount and timing of our capital expenditures for calendar year 2009 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 will be sufficient to satisfy our budgeted non-acquisition capital expenditures, working capital and debt service obligations for 2009. 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 current credit market volatility be prolonged for several years, 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 total approximately \$0.2 million, and counterparty risks related to our trade credit. Our cash accounts 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 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.

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The table below sets forth our contractual cash obligations as of December 31, 2008:

	Total	2009	2010-2011 (in thousands)	2012-2013	and after
Contractual Cash Obligations					
Long-term debt	\$ 250,696	\$ 160	\$ 137,144	\$ 113,392	\$
Operating leases	5,177	1,110	2,100	1,940	27
Total contractual cash obligations	\$ 255,873	\$ 1,270	\$ 139,244	\$ 115,332	\$ 27

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, 2008, 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 would result in an increase in interest expense of \$2.5 million annually. A 100-basis point decrease would result in a decrease in interest expense of \$2.5 million annually.

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, 2008 are shown in the following table:

	Crude Oil (Bbls)				Natural Gas (MMBtu)			
	Floors		Ceilings		Floors		Ceilings	
	Per Day	Price	Per Day	Price	Per Day	Price	Per Day	Price
Collars								
2009	1,371	\$ 59.46	1,371	\$ 81.92	10,501	\$ 7.14	10,501	\$ 11.31
2010	500	\$ 60.00	500	\$ 80.00	13,000	\$ 7.00	13,000	\$ 9.92
Secondary Floors								
	Per Day	Price						
Year								
2009	800	\$ 75.00						
Bare Floors								
	Per Day	Price			Per Day	Price		
Year								
2009	1,501	\$ 68.35			5,000	\$ 7.00		
2010	2,200	\$ 70.00			5,000	\$ 7.00		

Both crude oil and natural gas floors and ceilings for 2009 cover the calendar year. Crude oil secondary floors for 2009 cover January through March, and crude oil bare floors for 2009 cover the calendar year. Natural gas bare floors for 2009 cover January through March, and November and December. Crude oil floors and ceilings for 2010 cover January through March. Crude oil bare floors for 2010 cover January through March. Natural gas floors and ceilings for 2010 cover January through March, and natural gas bare floors for 2010 cover January through March.

Based on December 31, 2008 NYMEX forward curves of natural gas and crude oil futures prices, we would expect to receive future cash payments of \$25.5 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 receive future cash payments under our natural gas and crude oil derivative arrangements of \$33.0 million, and if future prices were to increase by 10% we would receive future cash payments of \$18.8 million.

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Item 8. *Financial Statements*

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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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, 2008 and 2007, 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, 2008. 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the 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 present fairly, in all material respects, the consolidated financial position of RAM Energy Resources, Inc. and subsidiaries at December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note A to the consolidated financial statements, the Company changed its method of accounting for uncertain income tax positions effective January 1, 2007.

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, 2008, 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 11, 2009 expressed an unqualified opinion on the effective operation of internal control over financial reporting.

/s/ UHY LLP

Houston, Texas

March 11, 2009

Table of Contents**RAM Energy Resources, Inc.****Consolidated Balance Sheets****(in thousands, except share and per share amounts)**

	As of December 31,	
	2008	2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 164	\$ 6,873
Cash, restricted	16,000	
Accounts receivable:		
Oil and natural gas sales, net of allowance of \$50 (\$287 at December 31, 2007)	8,702	15,136
Joint interest operations, net of allowance of \$515 (\$428 at December 31, 2007)	818	687
Income taxes		58
Other, net of allowance of \$35 (\$26 at December 31, 2007)	4,045	2,180
Derivative assets	21,006	
Prepaid expenses	2,330	1,928
Deferred tax asset		3,786
Other current contingencies	2,816	
Other current assets	4,141	842
Total current assets	60,022	31,490
PROPERTIES AND EQUIPMENT, AT COST:		
Proved oil and natural gas properties and equipment, using full cost accounting	683,341	573,470
Unevaluated oil and natural gas properties		26,895
Other property and equipment	9,460	8,787
	692,801	609,152
Less accumulated depreciation, amortization and impairment	(396,301)	(67,529)
Total properties and equipment	296,500	541,623
OTHER ASSETS:		
Deferred tax asset	28,724	
Derivative assets	4,531	
Deferred loan costs, net of accumulated amortization of \$1,282 (\$4,540 at December 31, 2007)	4,015	5,135
Other	2,053	1,994
Total assets	\$ 395,845	\$ 580,242
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	\$ 26,370	\$ 11,121
Oil and natural gas proceeds due others	7,218	7,800
Other	982	1,402
Accrued liabilities:		
Compensation	2,893	3,807
Interest	865	3,794
Franchise taxes	1,300	1,286
Income taxes	399	203
Contingencies	16,000	
Other		75
Deferred income taxes	5,779	
Derivative liabilities		5,302
Asset retirement obligations	1,093	1,904
Long-term debt due within one year	160	29,231

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Total current liabilities	63,059	65,925
OIL & NATURAL GAS PROCEEDS DUE OTHERS	2,523	2,383
DERIVATIVE LIABILITIES		3,073
LONG-TERM DEBT	250,536	306,516
DEFERRED INCOME TAXES		71,051
ASSET RETIREMENT OBLIGATIONS	29,106	25,741
UNCERTAIN TAX POSITIONS		6,855
COMMITMENTS AND CONTINGENCIES	900	
STOCKHOLDERS' EQUITY:		
Common stock, \$0.0001 par value, 100,000,000 shares authorized, 79,423,574 and 60,842,836, shares issued, 78,532,134 and 59,971,945 shares outstanding at December 31, 2008 and 2007, respectively	8	6
Additional paid-in capital	220,800	131,625
Treasury stock 891,440 shares (889,666 shares at December 31, 2007) at cost	(4,027)	(3,945)
Accumulated deficit	(167,060)	(28,988)
Stockholders' equity	49,721	98,698
Total liabilities and stockholders' equity	\$ 395,845	\$ 580,242

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

Table of Contents**RAM Energy Resources, Inc.****Consolidated Statements of Operations**

(in thousands, except share and per share amounts)

	Years ended December 31,		
	2008	2007	2006
REVENUES AND OTHER OPERATING INCOME:			
Oil and natural gas sales			
Oil	\$ 117,036	\$ 55,000	\$ 48,013
Natural gas	47,884	17,830	14,232
NGLs	17,770	9,047	5,770
Realized losses on derivatives	(10,472)	(2,669)	(4,650)
Unrealized gains (losses) on derivatives	33,257	(10,056)	6,239
Gain on sale of assets	10	61	142
Other	372	427	498
Total revenues and other operating income	205,857	69,640	70,244
OPERATING EXPENSES:			
Oil and natural gas production taxes	10,480	4,869	3,329
Oil and natural gas production expenses	38,030	21,574	18,266
Depreciation and amortization	46,758	18,948	13,252
Accretion expense	2,207	704	535
Impairment	282,465		
Share-based compensation	2,563	989	2,308
General and administrative, overhead and other expenses, net of operator s overhead fees	20,305	11,891	9,300
Total operating expenses	402,808	58,975	46,990
Operating income (loss)	(196,951)	10,665	23,254
OTHER INCOME (EXPENSE):			
Interest expense	(24,182)	(20,757)	(17,050)
Interest income	208	1,047	309
Other expense	(13,536)	(57)	
INCOME (LOSS) BEFORE INCOME TAXES	(234,461)	(9,102)	6,513
INCOME TAX PROVISION (BENEFIT)	(96,389)	(7,852)	1,465
Net income (loss)	\$ (138,072)	\$ (1,250)	\$ 5,048
BASIC EARNINGS (LOSS) PER SHARE	\$ (1.95)	\$ (0.03)	\$ 0.16
BASIC WEIGHTED AVERAGE SHARES OUTSTANDING	70,629,452	41,240,021	30,808,065
DILUTED EARNINGS (LOSS) PER SHARE	\$ (1.95)	\$ (0.03)	\$ 0.16
DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING	70,629,452	41,240,021	32,105,885

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

Table of Contents**RAM Energy Resources, Inc.****Consolidated Statements of Stockholders' Equity (Deficit)****Years ended December 31, 2008, 2007, and 2006****(In thousands, except share amounts)**

	Common Stock		Additional	Treasury Stock		Accumulated	Stockholders
	Shares	Amount	Paid-In Capital	Shares	Amount	Deficit	Equity (Deficit)
BALANCE, January 1, 2006	26,492,286	\$ 2	\$ 94		\$	\$ (20,865)	\$ (20,769)
Net income						5,048	5,048
Dividends declared						(500)	(500)
Stock redemption & cancellation	(892,286)		(93)			(9,699)	(9,792)
Net cost of acquisition, less cash acquired, May 8, 2006	7,700,000	1	(1)			(422)	(422)
Repurchase of stock				837,275	(3,768)		(3,768)
Share-based compensation	976,805		2,308				2,308
 BALANCE, December 31, 2006	 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						(138,072)	(138,072)
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)	 \$ (167,060)	 \$ 49,721

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,		
	2008	2007	2006
OPERATING ACTIVITIES:			
Net income (loss)	\$ (138,072)	\$ (1,250)	\$ 5,048
Adjustments to reconcile net income (loss) to net cash provided by operating activities-			
Depreciation and amortization	46,758	18,948	13,252
Amortization of deferred loan costs and Senior Notes discount	1,197	945	988
Write off of loan fees due to debt refinancing		2,435	1,055
Accretion expense	2,207	704	535
Impairment	282,465		
Unrealized (gain) loss on derivatives	(33,257)	10,056	(6,239)
Deferred income taxes provision (benefit)	(97,024)	(9,165)	1,311
Other expense	13,184		
Share-based compensation	2,563	989	2,308
Loss (gain) on disposal of other property, equipment and subsidiary	180	(61)	(142)
Undistributed losses on investment	165	57	
Changes in operating assets and liabilities, net of acquisitions			
Accounts receivable	4,168	(2,775)	1,012
Prepaid expenses and other assets	(4,283)	(117)	229
Accounts payable and proceeds due others	14,606	(3,626)	4,173
Accrued liabilities and other	(3,917)	(1,286)	6,025
Restricted cash	(16,000)		
Income taxes payable	(46)	1,313	105
Asset retirement obligations	(440)	(125)	
Total adjustments	212,526	18,292	24,612
Net cash provided by operating activities	74,454	17,042	29,660
INVESTING ACTIVITIES:			
Payments for oil and natural gas properties and equipment	(84,723)	(40,101)	(28,145)
Proceeds from sales of oil and natural gas properties	2,950	170	3,565
Payments for other property and equipment	(1,275)	(1,394)	(812)
Proceeds from sales of other property and equipment	23	71	461
Proceeds from sale of subsidiary, net of cash	308		
Acquisition of Ascent, net of cash acquired	35	(199,726)	(4,187)
Cash acquired in reverse merger			3,801
Other investments	114	(212)	
Net cash used in investing activities	(82,568)	(241,192)	(25,317)
FINANCING ACTIVITIES:			
Payments on long-term debt	(175,306)	(921)	(88,094)
Proceeds from borrowings on long-term debt	90,253	199,508	107,443
Payments for deferred loan costs	(74)	(1,480)	(2,981)
Stock redemption			(9,792)
Stock repurchased	(82)	(177)	(3,768)
Common stock offering, net of direct costs		27,366	
Warrants exercised	86,614	6	
Dividends paid			(500)
Net cash provided by financing activities	1,405	224,302	2,308
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(6,709)	152	6,651
CASH AND CASH EQUIVALENTS, beginning of year	6,873	6,721	70

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CASH AND CASH EQUIVALENTS, end of year	\$	164	\$	6,873	\$	6,721
SUPPLEMENTAL CASH FLOW INFORMATION:						
Cash paid for income taxes	\$	682	\$	18	\$	124
Cash paid for interest	\$	25,813	\$	16,936	\$	10,080
DISCLOSURE OF NON CASH INVESTING AND FINANCING ACTIVITIES:						
Accrued interest added to principal balance of credit facility	\$		\$	481	\$	2,848
Loan fees added to principal balance of credit facility	\$		\$	4,400	\$	
Issuance of stock and warrants for Ascent merger	\$		\$	101,065	\$	
Asset retirement obligations	\$	787	\$	16,140	\$	

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, 2008 and 2007

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

1. *Nature of Operations and Organization*

On May 8, 2006, Tremis Energy Acquisition Corporation, or Tremis, acquired RAM Energy, Inc., or RAM Energy, through the merger of a subsidiary of Tremis 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 Tremis, its subsidiary, RAM Energy and the stockholders of RAM Energy. Upon completion of the merger, RAM Energy became a wholly-owned subsidiary of Tremis and Tremis changed its name to RAM Energy Resources, Inc.

Tremis 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, Tremis 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.

Upon consummation of the merger, the stockholders of RAM Energy received an aggregate of 25,600,000 shares of Tremis common stock and \$30.0 million of cash. The merger agreement provided, among other things, that, prior to the consummation of the merger, RAM Energy was entitled to either pay its stockholders a one-time extraordinary dividend or effect one or more redemptions of a portion of its outstanding stock, although the aggregate amount of such cash payments to the RAM Energy stockholders could not exceed the difference between \$40.0 million and the aggregate amount of cash they would receive from Tremis in the merger. On April 6, 2006, RAM Energy redeemed a portion of its outstanding stock for an aggregate consideration of \$10.0 million.

The merger was accounted for as a reverse acquisition. Because Tremis 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 Tremis 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, Oklahoma, New Mexico and West Virginia.

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

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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. The Company had capitalized costs related to unevaluated properties of \$26.9 million as of December 31, 2007. All capitalized costs were included in the amortization base as of December 31, 2008.

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 in effect at the time of the calculation 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 oil and natural gas properties exceeded the Ceiling Limitation resulting in reduction in the carrying value of our oil and natural gas properties by \$282.0 million. The after-tax effect of this reduction in 2008 was \$179.6 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 \$5.0 million, \$2.9 million and \$2.3 million for the years ended December 31, 2008, 2007, and 2006, 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 amortization and depreciation 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, 2008 and 2007 is approximately \$5.0 million and \$4.0 million, respectively.

In accordance with the impairment provisions of Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, 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.

Table of Contents**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, 2008 and 2007, the Company's gas imbalances were immaterial.

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 2008 and 2007, approximately 53% and 50%, respectively, of total revenues were to one customer. During 2006, approximately 75% of total revenues were to two customers with sales to each of 62% and 13%. 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 2008 and 2007 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,	
2009	\$1,195
2010	\$1,195
2011	\$1,139
2012	\$ 486

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 \$0.5 million, \$0.2 million and \$0.3 million for the years ended December 31, 2008, 2007, and 2006, 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

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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 present value of proved reserves on spot prices on the date of the estimate. 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 2007 and 2006 have been made to conform to the 2008 presentation. These reclassifications had no effect on net income or loss or cash flows from operating, investing or financing activities.

14. Derivatives

The Company applies the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. SFAS No. 133 requires companies to recognize all derivative instruments as either assets or liabilities in the statement of financial position at fair value.

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 as required by SFAS No. 133 in order to receive hedge accounting treatment. Accordingly, all gains and losses on the derivative instruments during 2008, 2007 and 2006 have been recorded in the statements of operations.

Table of Contents**15. Earnings (Loss) per Common Share**

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

	2008	2007	2006
Net income (loss)	\$ (138,072)	\$ (1,250)	\$ 5,048
Weighted average shares basic	70,629,452	41,240,021	30,808,065
Dilutive effect of unvested stock grants			78,864
Dilutive effect of warrants			1,218,956
Weighted average shares dilutive	70,629,452	41,240,021	32,105,885
Basic earnings (loss) per share	\$ (1.95)	\$ (0.03)	\$ 0.16
Diluted earnings (loss) per share	\$ (1.95)	\$ (0.03)	\$ 0.16

For the years ended December 31, 2008 and 2007 the Company excluded unvested stock grants of 81,832 shares and 88,138 shares, respectively, from the calculation of diluted earnings (loss) per share as the effect was antidilutive.

16. Asset Retirement Obligations

SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends FASB Statement No. 19 *Financial Accounting and Reporting by Oil and Gas Producing Companies*. SFAS No. 143 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, 2008 and 2007 (in thousands):

	2008	2007
Liability for asset retirement obligations, beginning of year	\$ 27,645	\$ 10,801
Accretion expense	2,207	704
Change in estimates	(751)	(657)
Obligations for wells acquired and wells drilled	2,051	17,328
Obligations for wells sold or retired	(953)	(531)
Liability for asset retirement obligations, end of year	30,199	27,645
Less: current asset retirement obligation	1,093	1,904
Long-term asset retirement obligations	\$ 29,106	\$ 25,741

Table of Contents**17. Income Taxes**

The Company accounts for income taxes under the liability method as prescribed by SFAS 109. 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.

18. Uncertain Tax Positions

Effective January 1, 2007, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). The Interpretation 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 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 applying FIN 48 must be reported as an adjustment to the opening balance of retained earnings in the year of adoption. The net impact of the cumulative effect of adopting FIN 48 on January 1, 2007, was a \$1.3 million decrease to retained earnings, with a corresponding increase to accrued interest related to uncertain tax positions.

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	\$

Related to the uncertain tax benefits noted above, the Company had recognized \$1.3 million in accrued interest at the date of implementation of FIN 48. 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, 2008 are the years ended December 31, 2006 and 2007 and the tax years open for audit for state tax authorities as of December 31, 2008

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are the years ended December 31, 2005, 2006 and 2007. Tax years ending prior to 2004 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 September 2006, the Financial Accounting Standards Board issued SFAS No. 157 *Fair Value Measurements* (SFAS 157), which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning on or after November 15, 2007. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, however, it does not require any new fair value measurements. The Company adopted SFAS 157 effective January 1, 2008. As a result of the adoption, we began incorporating a credit risk assumption into the fair value measurement of our derivatives. See Note I and Note J.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159). This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by the Statement permits all entities to choose to measure eligible items at fair value at specified election dates. SFAS 159 is effective for fiscal years beginning after November 15, 2007. The Company adopted SFAS 159 effective January 1, 2008 and the adoption had no impact on its financial position or results of operations as we did not elect fair value measurement for additional financial instruments.

In December 2007, the FASB issued SFAS No. 141 (Revised), *Business Combinations* (SFAS 141(R)), which significantly changes the financial accounting and reporting of business combination transactions. SFAS 141(R) 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. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The adoption of this pronouncement may have an impact on the accounting for any acquisition the Company may make after January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51* (SFAS 160). This statement amends ARB No. 51 to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 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, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company does not expect the adoption of this pronouncement to have an impact on its financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS 161). This Statement changes the disclosure requirements for derivative instruments and hedging activities. Among other requirements, SFAS 161 requires enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and

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(c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The Company adopted SFAS 161 on January 1, 2009 and will begin reporting the enhanced disclosures in its Form 10-Q for the quarter ended March 31, 2009. The adoption of SFAS 161 did not have a material impact on the Company's financial statements.

On December 31, 2008, the Securities and Exchange Commission (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 use of a twelve-month average price could have an effect on the Company's depletion rates for its natural gas and crude oil properties. The new rule is effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, pending the potential alignment of certain accounting standards by the FASB with the new rule. The Company plans to implement the new requirements in its Annual Report on Form 10-K for the year ended December 31, 2009. The Company is currently evaluating the impact of this new rule on its consolidated financial statements and related disclosures.

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, 2008, approximately \$14.3 million principal and accrued interest amount 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 with the provisions of Statement of Financial Accounting Standards (SFAS) No. 141, Business Combinations (SFAS 141). The initial acquisition cost, the preliminary allocation to assets and liabilities, as adjusted by minimal subsequent purchase price adjustments are as follows (in thousands):

	Revised 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

Table of Contents**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

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, 2006. 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	Year ended December 31, 2006 (unaudited)
Revenue	\$ 116,216	\$ 143,957
Net loss	\$ (17,396)	\$ (15,560)
Basic and diluted loss per share	\$ (0.31)	\$ (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):

	2008	2007
11.5% Senior Notes due 2008, net of discount	\$	\$ 28,393
Credit facility	250,387	306,357
Installment loan agreements	309	997
	250,696	335,747
Less amount due within one year	160	29,231
	\$ 250,536	\$ 306,516

The amounts of required principal payments as of December 31, 2008, are as follows (in thousands):

2009	\$ 160
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2010	114
2011	137,030
2012	113,392
	\$ 250,696

Table of Contents**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.

At December 31, 2007, the unamortized original issue discount associated with the Notes was immaterial.

2. Revolving Credit Facility

New 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 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 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 will bear 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 five-year term, with the interest rate being LIBOR plus 7.5%.

Advances under the new facility are secured by liens on substantially all properties and assets of the Company and its subsidiaries, including Ascent and its subsidiaries. The loan agreement 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. The Company is 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. The Company was in compliance with all of its covenants in the credit facility at December 31, 2008. 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. At December 31, 2008, \$137.0 million was outstanding under the revolving credit facility and \$113.4 million was outstanding under the term facility.

D LEASES

The Company leases office space and certain equipment under non-cancelable operating lease agreements that expire on various dates through 2013. Approximate future minimum lease payments for operating leases at December 31, 2008 are as follows (in thousands):

Year Ending December 31,	
2009	\$ 1,110
2010	1,057
2011	1,043
2012	1,029
2013	911
2014 and thereafter	27
	\$ 5,177

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Rent expense of approximately \$1.2 million, \$0.5 million, and \$0.4 million was incurred under operating leases in the years ended December 31, 2008, 2007, and 2006, 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 2008, 2007, and 2006 of \$0.6 million, \$0.3 million and \$0.7 million, respectively.

F CAPITAL STOCK

RAM Energy, Inc. paid cash dividends of \$0.5 million for the year ended December 31, 2006 prior to being acquired by the Company.

On April 6, 2006, RAM Energy, Inc. redeemed a portion of the outstanding shares of its common stock for an aggregate redemption price of approximately \$10.0 million.

On May 8, 2006, the Company acquired RAM Energy, Inc. by merger in exchange for an issuance of 25,600,000 shares of common stock and \$30.0 million in cash. RAM Energy, Inc. is now a wholly-owned subsidiary of the Company. As a result of the merger, RAM Energy, Inc. was recapitalized so that the historical basis of its assets and liabilities remain intact. The only operations of the parent company included in the results of operations for 2006 are those that occurred subsequent to the date of the merger.

Also, 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 152,265 shares of common stock at an average price of \$5.59 per share. The shares purchased by the Company are held as treasury shares.

On September 22, 2006, the Company purchased 739,175 shares of its common stock in a privately negotiated transaction. The purchase price was \$4.295 per share, and the shares are included in treasury stock at December 31, 2008.

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. As a result of the acquisition, Ascent is now a wholly-owned subsidiary of the Company.

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.

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The Company has outstanding options to purchase up to 275,000 units at any time on or prior to May 11, 2009, each unit consisting of one share of the Company's common stock and two warrants. The warrants included in the units have expired by their terms and as a result, the unit options currently are exercisable, at \$9.90 per unit, only for a single share of the Company's common stock.

G INCOME TAXES

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

	Years Ended December 31,		
	2008	2007	2006
Current	\$ (912)	\$ (1,313)	\$ (154)
Deferred	97,301	9,165	(1,311)
Benefit (provision) for income tax expense	\$ 96,389	\$ 7,852	\$ (1,465)

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.

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

	Years Ended December 31,		
	2008	2007	2006
Income tax benefit (provision) at the federal statutory rate (34%)	\$ 79,717	\$ 3,039	\$ (2,214)
State income tax benefit, net of federal benefit	6,378	732	781
Meals and entertainment expense	(102)	(18)	(21)
Non-deductible dues	(33)	(13)	(17)
Previously unrecognized tax benefits	11,613	3,715	
Interest on previously unrecognized tax benefits	(127)	363	
Other	(1,057)	34	6
Income tax benefit (provision)	\$ 96,389	\$ 7,852	\$ (1,465)

The Company's income tax provision 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.

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

	December 31,	
	2008	2007
Deferred tax assets:		
Current:		
Derivative liabilities	\$	\$ 3,483
Accrued expenses and other	2,672	1,752
Total current deferred tax assets	\$ 2,672	\$ 5,235
Valuation allowance	(81)	
Net current deferred tax assets	\$ 2,591	\$ 5,235
Noncurrent:		
Net operating loss carryforward	\$ 33,735	\$ 51,694
Accrued liabilities and other	4,326	6,378
	\$ 38,061	\$ 58,072
Valuation allowance	(1,150)	(19,409)
Net noncurrent deferred tax assets	\$ 36,911	\$ 38,663
Deferred tax liabilities:		
Current:		
Prepaid expenses and other	\$ (8,370)	\$ (134)
Total current deferred tax liability	(8,370)	(134)
Noncurrent:		
Depreciable/depletable property, plant and equipment	\$ (8,366)	\$ (110,979)
Other	179	(50)
Total noncurrent deferred tax liabilities	\$ (8,187)	\$ (111,029)
Net noncurrent deferred tax liability	\$ (16,557)	\$ (111,163)
Net deferred tax asset (liability)	\$ 22,945	\$ (67,265)

As of December 31, 2008, the Company anticipates net operating loss carryforwards of approximately \$151.5 million for federal income tax reporting purposes, \$138.2 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 2026. 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 \$61.9 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 of FAS 109 that it will more likely than not realize a benefit in future periods. During the year ended December 31, 2008 the Company recorded a decrease in the valuation allowance of \$18.1 million. The decrease is

primarily due to a reduction in the recorded deferred tax asset associated with net operating losses that the Company does not currently believe are ultimately recoverable and the associated valuation allowance that the Company had placed on such deferred tax assets in a prior period.

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H COMMITMENTS AND CONTINGENCIES

Sacket v. Great Plains Pipeline Company, et al. In April 2002, a lawsuit was filed in the District Court for Woods County, Oklahoma against RAM Energy, Inc., certain of its subsidiaries and various other individuals and unrelated companies, by a lessor of certain oil and gas leases from which production was sold to a gathering system owned and operated by Magic Circle Energy Corporation (Magic Circle) or its wholly-owned subsidiary, Carmen Field Limited Partnership (CFLP). The lawsuit covers the period from first sales from the subject lease to a current date. In 1998, both Magic Circle and CFLP became wholly-owned subsidiaries of RAM Energy, Inc. The lawsuit was filed as a class action on behalf of all royalty owners under leases owned by any of the defendants during the period Magic Circle or CFLP owned and operated the gathering system. The petition claims that additional royalties are due because Magic Circle and CFLP resold oil and gas purchased at the wellhead for an amount in excess of the price upon which royalty payments were based and paid no royalties on natural gas liquids extracted from the gas at plants downstream of the system. Other allegations include under-measurement of oil and gas at the wellhead by Magic Circle and CFLP, failure to pay royalties on take or pay settlement proceeds, failure to properly report deductions for post-production costs in accordance with Oklahoma's check stub law and related tort and contract claims.

On January 11, 2007, the Court entered an order certifying the plaintiff's proposed class. 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 October 14, 2008, the trial court preliminarily approved the settlement and scheduled a fairness hearing. Following that preliminary approval, the entire settlement amount was deposited in escrow by the defendants pending final approval of the settlement. 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. Absent the filing of an appeal, the judgment will become final on April 4, 2009, promptly after which the plan of distribution will be 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. These escrowed shares will remain in escrow until the judgment becomes final or the litigation is otherwise resolved. At such time as the litigation is finally resolved, the former stockholders of RAM Energy have 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 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 the Company out of the escrow. 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.

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. Judgment has not yet been entered in the case, but is expected to be in the range of \$3.2 million. We plan to appeal the judgment, when entered.

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 incurred by us in connection with this and other pending litigation, subject to a sharing arrangement. After giving effect to such sharing

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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. The balance in the escrow account is sufficient to satisfy the former Ascent owners' indemnification obligation with respect to this lawsuit. 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

Effective January 1, 2008, the Company prospectively adopted the provisions of SFAS No. 157 *Fair Value Measurements* (SFAS 157) for financial assets and financial liabilities reported or disclosed at fair value. As permitted by FASB Staff Position No. SFAS 157-2, the Company elected to defer implementation of the provisions of SFAS 157 for non-financial assets and non-financial liabilities until January 1, 2009, except for non-financial items that are recognized or disclosed at fair value in the financial statements on a recurrent basis.

SFAS 157 refines the definition of fair value, provides a framework for measuring fair value and expands disclosures about fair value measurements. SFAS 157 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. As of December 31, 2008, the fair value measurement of our net derivative assets 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.

J DERIVATIVE CONTRACTS

During 2008, 2007 and 2006, 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 as required by SFAS No. 133 in order to receive hedge accounting treatment. Accordingly, all gains and losses on the derivative instruments during 2008, 2007 and 2006 have been recorded in the statements of operations.

The Company's derivative positions at December 31, 2008 are shown in the following table:

	Crude Oil (Bbls)				Natural Gas (MMbtu)			
	Floors	Price	Ceilings	Price	Floors	Price	Ceilings	Price
	per day		per day		per day		per day	
Collars								
2009	1,371	\$ 59.46	1,371	\$ 81.92	10,501	\$ 7.14	10,501	\$ 11.31
2010	500	\$ 60.00	500	\$ 80.00	13,000	\$ 7.00	13,000	\$ 9.92
	Secondary Floors							
Year	per day	Price						
2009	800	\$ 75.00						
	Bare Floors				Bare Floors			
Year	per day	Price			per day	Price		
2009	1,501	\$ 68.35			5,000	\$ 7.00		
2010	2,200	\$ 70.00			5,000	\$ 7.00		

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Both crude oil and natural gas floors and ceilings for 2009 cover the calendar year. Crude oil secondary floors for 2009 cover January through March, and crude oil bare floors for 2009 cover the calendar year. Natural gas bare floors for 2009 cover January through March, and November and December. Crude oil floors and ceilings for 2010 cover January through March. Crude oil bare floors for 2010 cover January through March. Natural gas floors and ceilings for 2010 cover January through March, and natural gas bare floors for 2010 cover January through March.

The Company's commodity derivative instruments consist of put options, costless collars and secondary floors. 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, 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. For the year ended December 31, 2008 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.

K LIQUIDITY

As of December 31, 2008, the Company has an accumulated deficit of \$167.1 million and a working capital deficit of \$3.0 million. Management believes that borrowings currently available to the Company under the Company's credit facilities (\$37.7 million available at December 31, 2008) and anticipated cash flows from operations will be sufficient to satisfy its currently expected capital expenditures, working capital, and debt service obligations through 2009. 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

In December 2004, the Financial Accounting Standards Board issued SFAS No. 123R, *Share-Based Payments* (SFAS No. 123R). SFAS No. 123R 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. The Company adopted the provisions of SFAS No. 123R effective January 1, 2006.

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 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, 2008, a maximum of 3,734,526 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, 2008 were as follows:

Year ended	Shares Repurchased	
	Number	Weighted Average Closing Price
December 31, 2006	98,100	\$ 6.04
December 31, 2007	33,616	\$ 5.28
December 31, 2008	20,549	\$ 3.98

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A summary of the status of the non-vested shares as of December 31, 2008, and changes during the three year period ended December 31, 2008, is presented below:

Nonvested Shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2006		\$
Granted	976,805	\$ 5.62
Vested	(330,000)	\$ 6.72
Forfeited		\$
Nonvested at December 31, 2006	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

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, 2008.

As of December 31, 2008, the Company had \$5.6 million of unrecognized compensation cost related to non-vested, share-based compensation related to awards granted under the Plan. That cost is expected to be recognized over a weighted-average period of 3 years. The related compensation expense recognized during the years ended December 31, 2008, 2007 and 2006 was \$2.6 million, \$1.0 million and \$2.3 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.

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, Oklahoma, and West Virginia. 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 at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods.

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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):

	2008	2007	2006
Proved oil and natural gas properties	\$ 683,341	\$ 573,470	\$ 185,284
Unevaluated oil and natural gas properties		26,895	
Accumulated depreciation, amortization and impairment	(391,270)	(63,480)	(45,203)
	\$ 292,071	\$ 536,885	\$ 140,081

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):

	2008	2007	2006
Acquisition of proved properties	\$ 10,091	\$ 299,573	\$ 4,476
Acquisition of unproved properties	2,691	24,642	705
Proceeds from sale of unproved properties			(3,565)
Development costs	57,084	12,921	18,475
Exploration costs	14,857	7,659	2,766
Exploration in progress			1,723
Sale of producing properties	(2,950)	(170)	
Additional asset retirement obligation	2,051	17,328	
	\$ 83,824	\$ 361,953	\$ 24,580
Amortization rate per equivalent oil barrel	\$ 17.99	\$ 12.86	\$ 9.78

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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, 2005	11,199	34,234	1,891
Extensions and discoveries	2,087	2,622	2
Sales of reserves in place			
Purchases of reserves in place	126	1,928	
Revisions of previous estimates	(1,864)	(3,220)	373
Production	(752)	(2,365)	(143)
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	641	19,435	1,126
Sales of reserves in place	(85)	(701)	
Purchases of reserves in place	151	135	
Revisions of previous estimates	(4,568)	(3,633)	(428)
Production	(1,187)	(6,082)	(354)
December 31, 2008	14,496	102,512	4,615
Proved developed reserves:			
December 31, 2006	6,954	26,888	1,671
December 31, 2007	13,552	50,990	2,565
December 31, 2008	9,235	59,717	2,710

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 were computed using 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):

	2008	2007	2006
Future cash inflows	\$ 1,294,803	\$ 2,722,099	\$ 894,626
Future production costs	(482,977)	(824,576)	(356,961)
Future development costs	(188,415)	(146,734)	(48,605)
Future income tax expenses	(99,862)	(574,169)	(158,602)
Future net cash flows	523,549	1,176,620	330,458
10% annual discount for estimated timing of cash flows	(248,300)	(578,225)	(150,717)
Standardized measure of discounted future net cash flows	\$ 275,249	\$ 598,395	\$ 179,741

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):

	2008	2007	2006
Standardized measure of discounted future net cash flows at beginning of year	\$ 598,395	\$ 179,741	\$ 226,660
Changes during the year:			
Sales and transfers of oil and natural gas produced, net of production costs	(134,180)	(55,434)	(46,272)
Net changes in prices and production costs	(545,183)	181,475	(97,697)
Extensions and discoveries, less related costs	77,851	11,444	30,560
Development costs incurred and revisions	2,816	976	(3,333)
Sales of reserves in place	(5,143)		
Purchases of reserves in place	3,494	435,261	4,476
Revisions of previous quantity estimates	(85,342)	41,042	2,107
Net change in income taxes	277,018	(223,002)	28,690
Accretion of discount	91,155	26,892	34,550
Net change	(323,146)	418,654	(46,919)
Standardized measure of discounted future net cash flows at end of year	\$ 275,249	\$ 598,395	\$ 179,741

Prices used in computing these calculations of future cash flows from estimated future production of proved reserves were \$44.15, \$93.90, and \$58.74 per barrel of oil at December 31, 2008, 2007, and 2006, respectively, \$5.33, \$7.00, and \$5.51 per thousand cubic feet of natural gas at December 31, 2008, 2007, and 2006, respectively and \$23.59, \$54.69, and \$36.51 per barrel of natural gas liquids at December 31, 2008, 2007, and 2006, respectively.

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	December 31,	2008 - Quarter Ended		
		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	312,975	29,868	30,989	28,976
Operating income (loss)	(243,322)	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	(254,755)	42,129	(20,671)	(1,164)
Income tax provision (benefit)	(94,580)	13,641	(14,809)	(641)
Net income (loss)	\$ (160,175)	\$ 28,488	\$ (5,862)	\$ (523)
Basic net income (loss) applicable to common stockholders per common share	\$ (2.08)	\$ 0.37	\$ (0.08)	\$ (0.01)
Diluted net income (loss) applicable to common stockholders per common share	\$ (2.08)	\$ 0.37	\$ (0.08)	\$ (0.01)
		2007 - Quarter Ended		
	December 31,	September 30,	June 30,	March 31,
		(In thousands except per share data)		
Net revenue	\$ 19,167	\$ 18,435	\$ 17,775	\$ 14,263
Net operating expenses	21,194	13,559	12,781	11,441
Operating income (loss)	(2,027)	4,876	4,994	2,822
Interest expense	(8,175)	(4,754)	(3,990)	(3,838)
Interest income	170	357	313	207
Other expense	(57)			
Income (loss) before income taxes	(10,089)	479	1,317	(809)
Income tax provision (benefit)	(3,747)	(4,291)	415	(229)
Net income (loss)	\$ (6,342)	\$ 4,770	\$ 902	\$ (580)
Basic net income (loss) applicable to common stockholders per common share	\$ (0.13)	\$ 0.12	\$ 0.02	\$ (0.02)
Diluted net income (loss) applicable to common stockholders per common share	\$ (0.13)	\$ 0.12	\$ 0.02	\$ (0.02)

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**

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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. 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 the report. This evaluation was performed by our management, with the participation of our Chief Executive Officer and Chief Financial Officer. Based on this evaluation of our

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disclosure controls and procedures as of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective.

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 (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. 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.

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) 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 concluded that the design and operations of our internal control over financial reporting at December 31, 2008 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the Company.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework*.

Based on our assessment, management concluded that, as of December 31, 2008, our internal control over financial reporting is effective based on those criteria, and we believe that we have no material internal control weaknesses in our financial reporting process.

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
Larry E. Lee
Chairman, President and Chief Executive Officer
March 12, 2009

/s/ G. LES AUSTIN
G. Les Austin
Senior Vice President and Chief Financial Officer
March 12, 2009

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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, 2008, 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 exists, 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, 2008, 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, 2008 and 2007, 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, 2008, and our report dated March 11, 2009, expressed an unqualified opinion on those consolidated financial statements.

/s/ UHY LLP

Houston, Texas

March 11, 2009

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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 is or will be set forth in the definitive proxy statement relating to the 2009 Annual Meeting of Stockholders of RAM Energy Resources, Inc., which is to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the Proxy Statement). This definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof 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. This definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof 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. This definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof 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.