RAM ENERGY RESOURCES INC
Form 10-K
March 16, 2011

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 000-50682

RAM Energy Resources, Inc.
(Exact name of registrant as specified in its charter)

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

(918) 663-2800
(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:
Common Stock, $.0001 par value

Securities registered pursuant to Section 12(g) of the Act:
None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405

of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

As of March 16, 2011, there were outstanding 78,378,233 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, 2010, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $85.0 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 2011 annual meeting of stockholders, which will be filed with the Securities and Exchange Commission, or SEC, no later than 120 days after December 31, 2010.

RAM ENERGY RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2010

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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 RAM Energy Resources, Inc. (formerly known as Tremisis Energy Acquisition Corporation) and its subsidiaries, as a combined entity.

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

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Louisiana and Oklahoma. Our producing properties are located in highly prolific basins with long histories of oil and natural gas operations. We have been active in our core producing areas of Texas, Oklahoma and Louisiana since our inception in 1987 and have grown through a balanced strategy of acquisitions, development and exploratory drilling. We have completed over 24 acquisitions of producing oil and natural gas properties and related assets for an aggregate purchase price in excess of $700.0 million. Through December 31, 2010, we have drilled or participated in the drilling of 846 oil and natural gas wells, approximately 94% of which were successfully completed and produced hydrocarbons in commercial quantities. Our management team has extensive technical and operating expertise in all areas of our geographic focus.

On December 8, 2010, we completed the sale to Milagro Producing, LLC, a privately owned company located in Houston, Texas, of all of our oil and natural gas properties and related assets located in the Boonsville and Newark East fields of Jack and Wise Counties, Texas. The effective date of the sale was October 1, 2010. The sale properties included all of our Bend Conglomerate shallow gas properties and all of our North Texas Barnett Shale properties, including both producing properties and undeveloped leasehold. We received net cash proceeds at closing of $42.3 million subject to customary post-closing adjustments. As of December 31, 2010, net proceeds including post-closing adjustments were $41.0 million. Proved reserves from these properties accounted for approximately 26.4 billion cubic feet equivalent (Bcfe) of natural gas, natural gas liquids and oil, or an estimated 13% of our year-end 2009 proved reserves of 204 Bcfe. Information as to our recent divestitures is set forth under Note B to the Consolidated Financial Statements.

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 Wichita, Wilbarger and Starr Counties, Texas, Pontotoc County, Oklahoma, and in several parishes in Louisiana.

As of December 31, 2010, our estimated net proved reserves were 24.4 MMBoe, of which approximately 54% were crude oil, 36% were natural gas, and 10% were natural gas liquids, or NGLs. The PV-10 Value of our proved reserves was approximately $364.2 million based on benchmark prices of $79.43 per Bbl of oil and $4.38 per Mcf of natural gas. The benchmark prices reflect the unweighted arithmetic average of the first-day-of-the-month price for oil and natural gas during each month of 2010, as required by SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting,* effective December 31, 2009. For more information regarding our PV-10 Value, including a reconciliation to the standardized measure of discounted future net cash flows relating to our estimated proved reserves, see Item 2. *Properties Oil and Natural Gas Reserves.* At December 31, 2010, our proved developed reserves comprised 62% of our total proved reserves.

At December 31, 2010, we owned interests in approximately 4,100 wells and were the operator of leases upon which approximately 3,200 of these wells are located. The PV-10 Value attributable to our interests in the properties we operate represented approximately 98% of our aggregate PV-10 Value as of December 31,

2010. 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, 2010, we drilled or participated in the drilling of 70 wells on our oil and natural gas properties, 62 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, 2010, we generated Modified EBITDA of $51.0 million from production averaging nearly 5,921 Boe per day. For more information regarding our Modified EBITDA, including a reconciliation to our net income (loss), see Item 6. *Selected Financial Data.*

Our Business Strategy and Strengths

Our primary objective is to enhance stockholder value by increasing our net asset value, net reserves and cash flow per share through acquisitions, development, exploitation, exploration and divestiture of oil and natural gas properties. Commencing June 2010, we initiated a comprehensive review of our strategic alternatives to determine the future direction of the Company. In the course of conducting this review, our development capital expenditures slowed to a lower level than originally projected. In late 2010, we decided to engage in strategic sales of certain of our non-core assets and refinance our indebtedness, as a result of which the pace of our development capital expenditures increased once again. The refinancing of our credit facility in March 2011 allows us to continue the development and exploitation of our existing properties and to pursue an increased exploration strategy while searching out selective acquisitions. As in the past, 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 continued period of financial industry uncertainty leading to more restrictive capital markets, we believe maintaining ample liquidity for capital drilling programs to be a critical component of our strategy. Our 2011 capital budget of $35.0 million is expected to be fully funded through operating cash flows.

Concentrate on Our Existing Core Areas. We intend to focus a significant portion of our growth efforts in our existing core areas in Texas, Oklahoma and Louisiana. Our oil and natural gas properties in our core areas are characterized by long reserve lives and production histories in multiple oil and natural gas horizons. We have a diversified and promising reserve base. 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, 2010, we have identified over 400 development and extension drilling projects and more than 45 recompletion/workover projects on our existing properties and wells. We intend to continue our focus on workovers, recompletions and development capital expenditures in 2011.

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 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 as was the case in 2010 when we disposed of over $50.0 million in assets.

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.

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We are encouraged by our success in our Osage concession and plan to continue exploration in that area. We will continue to acquire, review and analyze 3-D seismic data to generate additional exploratory prospects. Since 2006, we have drilled 28 gross (12.9 net) exploratory wells and experienced an 82% success rate. Our exploration efforts utilize available geological and geophysical technologies to reduce our exploration and drilling risks and, therefore, maximize our probability of success. Combined with our continued emphasis on development capital expenditures, we believe these exploratory 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, on average, over 27 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 2010, approximately 54% of our estimated proved reserves were oil, 36% were natural gas and 10% were NGLs. We believe this balanced commodity mix, combined with our prudent use of derivative contracts, will provide sufficient diversification of sources of cash flow and will lessen the risk of significant and sudden decreases in revenue from localized or short-term commodity price movements.

Operating Efficiency and Control. We currently operate wells that represent approximately 98% of our aggregate PV-10 Value at December 31, 2010. 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, 2010, we drilled or have participated in the drilling of 846 oil and natural gas wells with over 94% success rate. We expect to continue to grow by utilizing our drilling expertise and developing and finding additional reserves, although our success rate may decline as we drill more exploratory wells.

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

Glossary of Oil and Natural Gas Terms

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

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

Bcf. One billion cubic feet of natural gas.

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

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

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

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

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

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

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

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

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

MBoe. One thousand Boe.

MMBoe. One million Boe.

Mcf. One thousand cubic feet of natural gas.

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

MMBtu. One million Btus.

MMcf. One million cubic feet of natural gas.

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

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

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

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

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

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

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

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

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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.

FORWARD LOOKING STATEMENTS

This report, including information included in, or incorporated by reference from 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;

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marketing of oil and natural gas;

property acquisitions and divestitures;

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.

Item 1A. *Risk Factors*

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

Risks Related to Our Business

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

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

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

worldwide and domestic supplies of oil and natural gas;

speculation in the price of commodities in the commodity futures market;

weather conditions;

the level of consumer demand;

the price and availability of alternative fuels;

the availability of drilling rigs and completion equipment;

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the availability of pipeline capacity;

the price and volume of foreign imports;

domestic and foreign governmental regulations and taxes;

the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

political instability or armed conflict in oil-producing regions; and

the overall economic environment.

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

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

Our oil and natural gas properties will become uneconomic when oil and natural prices decline to the point at which our revenues are insufficient to recover our lifting costs. For example, in 2010, our average lifting costs were approximately $18.49 per Boe, or $3.08 per Mcfe. A market price decline below that price would result in our having to shut in certain production until prices increase.

A 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 2011. However, if oil and natural gas prices decline or reduce to lower levels for a prolonged period of time, we may be unable to continue to fund capital expenditures at historical levels due to the decreased cash flows that will result from such reduced oil and natural gas prices. Additionally, a 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 credit facilities, which will further reduce the availability of cash to fund our operations. As a result, we may have to reduce our capital expenditures in future years. A decrease in our capital expenditures will likely result in a decrease in our production levels.

Reduced development capital expenditures in 2011 could result in decreased production in 2012.

In 2010, our capital expenditures related to development and exploitation activities were approximately $27.9 million. For 2011, we have budgeted $23.0 million for capital expenditures related to development and exploitation activities and related geological and geophysical costs, an 18% decrease over the prior year. This anticipated decline in capital expenditures for development and exploitation activities could result in a decrease in production in 2012 and possibly beyond, unless our development and exploitation capital expenditures are subsequently increased, we find increased productive reserves through our exploration program or we acquire more production through strategic acquisitions.

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

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

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

Oil prices have improved significantly in 2010 as compared to 2009 while natural gas prices continue to stagnate. Our profitability is directly related to the prices we receive for the sale of the oil and natural gas we produce. In early July 2008, commodity prices reached record levels in excess of $140.00 per barrel for crude oil and $13.00 per Mcf for natural gas. The 2008 year ended with market prices dropping to $44.00 for crude oil and $4.00 for natural gas, a 69% to 73% decline from the earlier highs. During 2009, market prices ended at a high of approximately $72.00 for crude oil and $4.00 for natural gas. As of December 31, 2010, crude oil prices continued to rise to approximately $87.00 while natural gas prices remained constant at approximately $4.00.

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.

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

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

Therefore, these estimates are inherently imprecise. For example, total revisions of our previous reserve estimates decreased proved reserves by 3.3 MMBoe or approximately 10% of our reserves at the beginning of the year. The revisions included a positive increase of 1.8 MMBoe or 5% of the beginning of the year reserves caused by higher oil and gas prices. This positive revision was offset by the downward revision of 1.1 MMBoe caused by the transfer of proved undeveloped to unproved categories as a result of changes to the company development plans during 2010, and 4.0 MMBoe of the downward revisions were mostly due to changes in well performance in our gas properties in South Texas.

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

As of December 31, 2010, approximately 38%, or 9.2 MMBoe, of our estimated proved reserves were proved undeveloped, and approximately 7%, or 1.7 MMBoe, were proved developed non-producing. In order to develop our proved undeveloped reserves, we estimate approximately $101.8 million of capital expenditures will be required. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future and after some investment of capital. In order to bring production on-line for our proved developed non-producing reserves, we estimate capital expenditures of approximately $8.3 million will be required. The estimated abandonment costs associated with our Louisiana production facilities make up the balance of our anticipated capital expenditures. Although we have estimated our reserves and the costs associated with these reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

You should not assume that the PV-10 Value and standardized measure of discounted future net cash flows included in this report represent the current market value of our estimated proved oil and natural gas reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. For example, our proved reserves and PV-10 Values as of December 31, 2010, were estimated using the 12-month unweighted arithmetic average of the first-day-of-the-month price of $79.43 per Bbl of oil (NYMEX West Texas Intermediate settle price) and $4.38 per Mcf of natural gas (Platts Henry Hub spot price). We then adjust these base prices to reflect appropriate basis, quality, and location differentials over that period in estimating our proved reserves. During 2010, our monthly average realized oil prices, excluding the effect of hedging, were as high as $86.84 per Bbl and as low as $71.92 per Bbl. For the same period, our monthly average realized natural gas prices before hedging were as high as $5.72 per Mcf and as low as $3.27 per Mcf. Many other factors will affect actual future net cash flows, including:

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

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

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

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

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

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

Operating hazards and uninsured risks may result in substantial losses.

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

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

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

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

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

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

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

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

The U.S. Congress has previously considered legislation to reduce emissions of greenhouse gases, including carbon dioxide, methane and nitrous oxide among others, which some studies have suggested may be contributing to warming of the earth s atmosphere. However, legislation to reduce greenhouse gases appears less likely in the near term. As a result, near term regulation of greenhouse gases, if any, is more likely to come from regulatory action by EPA or by the several states that have already taken legal measures to reduce emissions of greenhouse gases.

As a result of the U.S. Supreme Court s decision on April 2, 2007 in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the Clean Air Act (CAA) definition of air pollutant, the Environmental Protection Agency (EPA) was required to determine whether emissions of greenhouse gases endanger public health or welfare. As a result, the EPA has adopted regulations requiring Clean Air Act (CAA) permitting of greenhouse gas emissions from stationary and mobile sources. On December 15, 2009, EPA promulgated its final rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, finding that (i) the current and projected emissions of six key well-mixed greenhouse gases, including carbon dioxide and methane, constitute a threat to public health and welfare, and (ii) the combined emissions from motor vehicles cause and contribute to the climate change problem which threatens public health and welfare. These findings did not themselves impose any requirements on industry or other entities, but were a prerequisite to EPA s adoption of greenhouse gas

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emission standards for motor vehicles. On May 7, 2010, EPA and the Department of Transportation s National Highway Traffic and Safety Administration, or NHTSA, promulgated a final action establishing a national program providing new standards for certain motor vehicles to reduce greenhouse gas emissions and improve fuel economy, with EPA adopting the standards under the CAA, and NHTSA adopting the standards as Corporate Average Fuel Economy standards under the Energy Policy and Conservation Act. While these motor vehicle regulations do not directly impact oil and natural gas production operations, the result of these actions are significant in that they automatically trigger application of certain CAA permit programs for stationary greenhouse gas emissions sources, potentially including oil and natural gas production operations. These programs, the Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs, have historically applied to sources of air pollutants subject to regulation with emissions exceeding 100 and 250 tons per year. To avoid the broad impact of such low permitting thresholds for greenhouse gas emission sources, on June 3, 2010, EPA promulgated its Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, to add new higher thresholds of 75,000 tons per year carbon dioxide equivalents (CO_2e) for modifications and 100,000 tons per year CO_2e for new sources.

Additionally, EPA has promulgated separate regulations requiring greenhouse gas emission reporting from certain industry sectors, including natural gas production. On October 30, 2009, EPA promulgated a final mandatory greenhouse gas reporting rule which will assist EPA in developing policy approaches to greenhouse gas regulation. This reporting rule became effective on December 29, 2009. On November 30, 2010, EPA promulgated additional mandatory greenhouse gas reporting rules that apply specifically to oil and natural gas production for implementation in 2011.

Though under review by the D.C. Circuit, EPA s rules promulgated thus far have survived petitions for stay, and are currently final and effective, and will remain so unless vacated or remanded by the court, or unless Congress adopts legislation preempting EPA s regulatory authority to address greenhouse gases under the CAA.

Beyond legislative and regulatory developments, there have been several recent court cases impacting this area of risk related to greenhouse gas emissions. The final decisions in these cases may expose us to similar litigation risk.

The decisions in these cases may expose us, as potentially an emitter of significant direct and indirect emission sources of greenhouse gases, to similar litigation risk.

International treaties. Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, an international treaty pursuant to which participating countries (not including the United States) agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Though the 16th meeting of the Council of the Parties in Mexico in November and December 2010 did not produce a legally binding final agreement, international negotiations continue, with the participation of the United States.

International developments, passage of state or federal climate control legislation or other regulatory initiatives, the implementation of regulations by EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which we conduct business, or further development of case law allowing claims based upon greenhouse gas emissions, could have an adverse effect on our operations and financial condition as a result of material increases in operating and production costs and litigation expense due to expenses associated with monitoring, reporting, permitting and controlling greenhouse gas emissions or litigating claims related to emissions of greenhouse gases, and the demand for oil and natural gas and increase the costs of our operations.

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

In 2009, 2010 and 2011, the administration of President Obama made budget proposals which, if enacted into law by Congress, would potentially increase and accelerate the payment of federal income taxes by independent producers of oil and natural gas. Proposals have included, but have not been not limited to, repealing the expensing of intangible drilling costs, repealing the deduction for the cost of qualified tertiary expenses, repealing the exception to the passive loss limitation for working interests in oil and natural gas properties, repealing the percentage depletion allowance, repealing the manufacturing tax deduction for oil and natural gas companies, and increasing the amortization period of geological and geophysical expenses. In 2009 and 2010, legislation which would have implemented the proposed changes was introduced but not enacted. It is unclear whether legislation supporting any of the above described proposals, or designed to accomplish similar objectives, will be introduced or, if introduced, would be enacted into law or, if enacted, how soon resulting changes would become effective. However, the passage of any legislation designed to implement changes in the U.S. federal income tax laws similar to the changes included in the budget proposals offered by the White House in 2009, 2010 and 2011 could eliminate certain tax deductions currently available with respect to oil and gas exploration and development, and any such changes (i) could make it more costly for us to explore for and develop our oil and natural gas resources and (ii) could negatively affect our financial condition and results of operations. On July 21, 2010, the President signed into law the Wall Street Transparency and Accountability Act of 2010 (the WSTA Act) which directs the Federal Reserve to create uniform standards for the management of certain risks associated with, among other things, the trading of certain derivatives over the counter (OTC). In recent years, we have maintained an active price and basis protection hedging program related to the oil and natural gas we produce. Additionally, we have used the OTC market exclusively for our oil and natural gas derivative contracts and have relied on our hedging activities to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. While the manner in which the Federal Reserve will implement the directives contained in the WSTA Act is unclear, we anticipate such implementation may include the imposition of clearing and standardization requirements for all derivatives currently traded on the OTC and could restrict trading positions in the energy futures markets. While the ultimate impact on us of such changes, if implemented, is unclear, we anticipate they may materially reduce our hedging opportunities and could negatively affect our revenues and cash flow during periods of low commodity prices.

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

We utilize hydraulic fracturing as a means to enhance the productive capability of our wells. Congress has previously considered legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills previously proposed before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. That proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could repeal the exemptions for hydraulic fracturing from the Safe Drinking Water Act. These legislative efforts have halted while EPA studies the issue of hydraulic fracturing in 2010, EPA initiated a Hydraulic Fracturing Research Study to address concerns that hydraulic fracturing may affect the safety of drinking water. As part of that process, EPA requested and received information from the major fracturing service providers regarding the chemical composition of fluids, standard operating procedures and the sites where they engage in hydraulic fracturing. In February 2011, EPA released its Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, proposing to study the lifecycle of hydraulic fracturing fluid and providing a comprehensive list of chemicals identified in fracturing fluid and flowback/produced water. These developments, as well as increased scrutiny of hydraulic fracturing activities by state authorities, may result in additional levels of regulation or level of complexity with respect to existing regulation at the federal and state levels that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing, which could result in limiting the productive capability of future wells in which we likely would utilize hydraulic fracturing and increase our costs of compliance and doing business.

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

As of December 31, 2010, our borrowing base under our old revolving credit facility was $145.0 million. As of the same date, we had outstanding advances under the revolving credit facility of $116.5 million, leaving an aggregate availability under our revolver of $28.5 million. However, because of the amount of our Modified EBITDA, the financial covenants set forth in our old credit facility would have limited us to additional borrowings under our revolving credit facility as of December 31, 2010, of $23.7 million. On March 14, 2011, we entered into a new revolving credit facility with a borrowing base of $150.0 million. Based on our Modified EBITDA for the four fiscal quarters ending December 31, 2010, our borrowings would not have been limited under the new revolving credit facility. Should our Modified EBITDA decline, we may be unable to borrow funds up to the full amount of our borrowing base. Our inability to borrow the full amount of our borrowing base under our revolving credit facility could reduce our current year capital expenditures if we do not meet our goal of funding our 2011 capital expenditures from our operating cash flow.

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

We use the full cost method of accounting for our investment in oil and natural gas properties. Under the full cost method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves are capitalized into a full cost pool. Capitalized costs in the pool are amortized and charged to operations using the units-of-production method based on the ratio of current production to total proved oil and natural gas reserves. To the extent that such capitalized costs, net of amortization, exceed the after tax present value of estimated future net revenues from our proved oil and natural gas reserves (using a 10% discount rate) at any reporting date, such excess costs are charged to operations. We incurred no impairment charge for 2010. In 2009, we recorded a $47.6 million charge for the impairment of our oil and natural gas properties. This amount was in addition to the $269.4 million charge we recorded in 2008. These writedowns are not reversible at a later date, even if the present value of our proved oil and natural gas reserves increases as a result of an increase in oil or natural gas prices. Further price declines could result in additional impairments of asset value.

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

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

- future oil and natural gas prices;
- the amount of recoverable reserves;
- future operating costs;
- future development costs;
- failure of titles to properties;
- costs and timing of plugging and abandoning wells; and

potential environmental and other liabilities.

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

We face intensive 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 will 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, which means that the change in the fair market value of these instruments is reported as a non-cash item in our statement of operations each quarter, which typically result in significant variability in our net income. Derivative contracts expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

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

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

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

Our ability to make payments on 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.

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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 agreements contain 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 agreements. Also, our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. A decline in oil and natural gas prices, or a prolonged period of oil and natural gas prices at lower levels, could eventually result in our failing to meet one or more of the financial covenants under our credit facilities, which could require us to refinance or amend the facilities 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 agreements. A default under our credit agreements, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit agreements. 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.

Risks Related to Our Common Stock

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

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

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

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

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

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders. We are currently authorized to issue 100,000,000 shares of common stock and 1,000,000 shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As of December 31, 2010, we had outstanding 78,386,983 shares of common stock. In addition, we have reserved an additional 1,960,271 shares for future issuance to our directors, officers and employees as restricted stock or stock option awards pursuant to our 2006 Long-Term Incentive Plan. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with future acquisitions, future issuances of our securities for capital raising purposes or for other business purposes. Future sales of substantial amounts of our common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

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

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

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

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

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 effected, these provisions of Delaware law, which are applicable even if other provisions of Delaware law or the charter or bylaws provide to the contrary, also provide that any director elected to fill a vacancy shall hold office for the remainder of the full term of the class of directors in which the vacancy occurred, rather than the next annual meeting of stockholders as would otherwise be the case, and until his or her successor is elected and qualifies.

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

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

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

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

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

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

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

None.

Item 2. ***Properties***

As we concentrate our holdings into areas that align with our objectives, we have determined to report our operations by state. Our principal properties in Texas primarily consist of the Electra/Burkburnett fields in Wichita and Wilbarger Counties and the La Copita field in Starr County. Our principal Oklahoma properties are the Northeast Fitts and Allen fields in Pontotoc and Seminole Counties. In Louisiana, our most significant property is the Lake Enfermer field in Lafourche Parish. During 2010, we drilled 62 gross wells (54.0 net) that were capable of production and experienced a success rate of 99%.

The following table summarizes our estimated proved oil and gas reserves by area as of December 31, 2010, and our average daily production by area for calendar year 2010:

	Average Daily Production	Oil	Gas	NGL	Equivalent	Percent of Proved

	Boe	MBbls	MMcf	MBbls	MBoe	Reserves
Texas	3,893	6,903	31,158	2,126	14,222	58%
Oklahoma	1,296	5,523	4,236	111	6,340	26%
Louisiana	532	409	16,555		3,168	13%
Other	200	251	1,659	138	666	3%
	5,921	13,086	53,608	2,375	24,396	100%

Texas Fields

The average daily production from our Texas fields was 3,893 Boe per day (66% of our total daily production) in 2010, a decrease of 15% over the previous year due to natural production declines not offset by increased drilling. We drilled a total of 58 gross (51.1 net) wells in our Texas fields, all of which were completed as wells capable of production. An additional three gross (3.0 net) wells were drilled to their objective depth and awaiting completion or pipeline connection at year end. As of December 31, 2010, the proved reserves in our Texas fields were 14.2 MMBoe and account for 58% of our total proved reserves. Our most significant Texas fields are as follows:

Electra/Burkburnett Fields. We drilled a total of 48 gross (48.0 net) wells during 2010 in our Electra/Burkburnett fields in Wichita and Wilbarger Counties, Texas and have drilled more than 347 wells in these fields since November 1, 2004. We have budgeted $8.0 million in 2011 to continue development of this field. We own our own drilling rig and pulling units deployed exclusively for operations in these fields, and employ approximately 91 field personnel. We continue to focus on reducing operating costs in these fields and are also working to improve production performance through recompletions, workovers and improved water injection performance. As of December 31, 2010, the estimated proved reserves in these fields were 6.6 MMBoe (27% of our total proved reserves).

South Texas. During 2010, our net daily production from our South Texas properties averaged 1,355 Boe per day and make up 27% (6.6 MMBoe) of our total proved reserves. We drilled six gross (5.8 net) wells in our La Copita field in Starr County, Texas during 2010. All completions were successful with initial production rates up to 482 Boe per day from the Vicksburg formation. We are the operator of all of the wells in our La Copita field. Due to continued low natural gas prices, we have allocated only $2.0 million of our 2011 non-acquisition capital budget to South Texas.

Oklahoma Fields

We produced an average of 1,296 Boe per day (22% of our total daily production) from our Oklahoma fields in 2010, a decrease of 19% over the previous year primarily due to natural production declines and weather-related interruptions. We drilled a total of three gross (2.9 net) wells in our Oklahoma fields, all of which were completed as wells capable of production. An additional three gross (2.8 net) wells were drilled to their objective depth and awaiting completion or pipeline connection at year end. As of December 31, 2010, the proved reserves in our Oklahoma fields were 6.3 MMBoe and account for 26% of our total proved reserves. Our most significant Oklahoma fields are as follows:

Northeast Fitts and Allen Fields. During 2010, we initiated the drilling of 3 gross (2.7 net) development wells in our Northeast Fitts unit in Pontotoc County, Oklahoma. No wells were drilled during 2009 in our Allen field of Pontotoc and Seminole Counties. The Northeast Fitts field produces from shallow McAlester and Hunton formations at depths less than 4,000 feet. We are the operator of the units and, as such, control the pace of operations. The majority of our value in the Northeast Fitts field is primarily a mature waterflood. Our Allen Field has future behind-pipe and undeveloped opportunities in shallow multi-pay reservoirs. The combined proved reserves from these two areas are 5.6 MMBoe (23% of our total proved reserves). We have budgeted $2.0 million for development costs in our Northeast Fitts and Allen fields in 2010.

Louisiana Fields

The average daily production from our Louisiana fields was 532 Boe per day (9% of our total daily production) in 2010, a decrease of 6% over the previous year due to natural production declines. We drilled a total of one gross (0.2 net) wells in our Louisiana fields, which was non-productive. As of December 31, 2010, the proved reserves in our Louisiana fields were 3.2 MMBoe and account for 13% of our total proved reserves.

The following table summarizes our 2010 drilling activity:

	Developed			Exploratory		
	Gross Wells Drilled(1)	Net Wells Drilled(1)	Completion Rate (%)	Gross wells Drilled	Net Wells Drilled	Completion Rate (%)
Texas	57	50.1	100%	1	1.0	100%
Oklahoma	1	0.9	100%	2	2.0	100%
Louisiana				1	0.2	
Other	1		100%			
	59	51.0	100%	4	3.2	75%

(1) Does not include seven gross (5.8 net) wells that were in the process of being completed at December 31, 2010, and does not include three gross (0.2 net) wells that were drilled in 2009 and waiting on pipeline connection.

Development, Exploitation and Exploration Programs

Development and Exploitation Program. Our future production and performance depends to a large extent on the successful development of our existing reserves of oil and natural gas. We have identified multiple development projects on our existing properties (substantially all of which are located in our core areas), and these projects involve both the drilling of development wells and extension wells. We are the operator of leases covering approximately 2,500 of the wells capable of production in which we own interests, and as such we are able to control expenses, capital allocation and the timing of development activities on these properties. We also own interests in, and operate, approximately 700 injection wells. During the year ended December 31, 2010, we drilled or participated in the drilling of 62 gross (54.0 net) development wells capable of production. Capital expenditures in connection with these activities during this period aggregated approximately $27.9 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 45 operated projects involving recompletions in existing wells that we operate, all of which involve reserves included in our proved reserves at December 31, 2010.

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. We have obtained a concession in Osage County, Oklahoma on over 56,000 acres with 100% working interest. We have 3-D seismic data covering approximately 16,000 acres and have obtained permits for shooting approximately 20,000 additional acres. During 2011, assuming the continuation of existing commodity prices for oil and natural gas, we expect to conduct only limited exploratory drilling, primarily on our Osage concession.

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, 2010, we participated in the drilling of four gross (3.2 net) exploratory wells. For 2011, we have budgeted $8.0 million for geological and geophysical activities relating to exploitation and exploration projects and $9.0 million for exploration, including leasehold acquisition, seismic and exploratory drilling. We are encouraged by the results of our Osage concession exploratory project in 2010 and plan to increase our spending in 2011.

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Oil and Natural Gas Reserves

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

To determine our estimated proved reserves, and as required by the SEC, we used the 12-month unweighted arithmetic average of the first-day-of-the-month price for the months of January through December 2010 calculated to be $4.38 per Mcf of natural gas and $79.43 per Bbl of oil. These prices were held constant for the life of the properties and adjusted for the appropriate market differentials.

As of December 31, 2010, our proved crude oil and natural gas reserves and PV-10 Value are presented below by reserve category. All of our proved reserves are located within the United States.

	Oil MBbl	Gas MMcf	NGL MBbl	MBoe	Reserve %	PV-10 M$
Proved developed producing	8,087	24,134	1,358	13,467	55%	$ 232,449
Proved developed nonproducing	327	7,642	128	1,729	7%	$ 26,903
Proved undeveloped	4,672	21,832	889	9,200	38%	$ 104,896
Total proved	13,086	53,608	2,375	24,396	100%	$ 364,248
Developed	8,414	31,776	1,486	15,196		$ 259,352
% Developed	64%	59%	63%	62%		71%

Our properties have a 13.7 year reserve-to-production ratio.

Proved Undeveloped Reserves

At December 31, 2010, our total proved undeveloped reserves were 9.2 MMBoe, comprised of 5.6 MMBbl of crude oil and natural gas liquids and 21.8 Bcf of natural gas. As a result of our 2010 development activities, we converted approximately 760 MBoe, or 5%, of our 2009 proved undeveloped reserves to proved developed. The capital costs to develop these reserves were approximately $13.0 million. Also during 2010, we drilled wells at 40 locations that did not include proved reserves as of December 31, 2009. We did not add any new proved undeveloped locations during 2010. Our projected costs to develop our remaining proved undeveloped reserves are $16.3 million in 2011, $36.0 million in 2012, $22.0 million in 2013, $15.7 million in 2014 and $11.8 million in 2015.

Unproved Reserves

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

Technologies Used to Establish Additions to Reserve Estimates

The revised rules permit the use of reliable technologies that have been field tested as evidence proven to establish with reasonable certainty quantities of proved reserves. They also permit assigning reserves to locations more than one offset away from standard development spacing if reasonable certainty can be established, and the estimates are economically producible. We evaluated the potential use of reliable technologies in connection with the preparation of our 2010 reserve estimates and have elected not to rely on the new rule as a means of assigning proved or unproved reserves. We are, however, actively using seismic interpretation to high grade our potential drilling locations. In future filings, we may use reliable technologies to assign reserves if the application can prove with a high degree of confidence that the estimated quantities can be recovered.

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Internal Controls over Reserves Estimate

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

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

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

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

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

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Reserve Reconciliation

Our total proved reserve reconciliation starting at year-end 2009 and ending year-end 2010 is as follows:

	Oil MBbl	Gas MMcf	NGL MBbl	MBoe
Total proved				
As of December 31, 2009	14,067	89,227	4,983	33,922
Extensions, discoveries and additions(a)	347	821	61	545
Sales(b)	(174)	(14,591)	(2,004)	(4,610)
Production	(995)	(4,816)	(364)	(2,161)
Revisions of previous estimates(c)	(159)	(17,033)	(301)	(3,300)
As of December 31, 2010	13,086	53,608	2,375	24,396

(a) We added 0.5 MMBoe in proved reserve extensions, discoveries and additions in 2010 primarily as a result of our development drilling in our Electra/Burkburnett field in North Texas and in our La Copita field in South Texas. A significant portion of these reserves is a result of drilling locations in our Electra/Burkburnett field that were not booked as proved locations at year-end 2009. The remainder of the extensions, discoveries and additions is primarily from wells drilled in South Texas not previously booked as proved and from an exploratory well in Osage County, Oklahoma.

(b) We divested 4.6 MMBoe of non-core natural gas assets in North Texas and Oklahoma during 2010.

(c) Total revisions of previous reserve estimates decreased proved reserves by 3.3 MMBoe or approximately 10% of our reserves at the beginning of the year. The revisions included a positive increase of 1.8 MMBoe or 5% of the beginning of the year reserves caused by higher oil and gas prices. This positive revision was offset by the downward revision of 1.1 MMBoe caused by the transfer of proved undeveloped to unproved categories as a result of changes to the company development plans during 2010, and 4.0 MMBoe of the downward revisions mostly due to changes in well performance in our gas properties in South Texas.

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

	As of December 31,		
	2010	2009	2008
Reserve Data:			
Proved developed reserves:			
Oil (MBbls)	8,414	8,814	9,235
Natural gas (MMcf)	31,776	46,159	57,635
Natural gas liquids (MBbls)	1,486	2,788	2,705
Total (MBoe)	15,196	19,295	21,546
PV-10 Value (in thousands)	$ 259,352	$ 222,516	$ 233,061

	As of December 31,		
	2010	**2009**	**2008**
Total Proved reserves:			
Oil (MBbls)	13,086	14,067	14,285
Natural gas (MMcf)	53,608	89,227	96,952
Natural gas liquids (MBbls)	2,375	4,983	4,325
Total (MBoe)	24,396	33,922	34,769
PV-10 Value (in thousands)	$ 364,248	$ 336,053	$ 322,131
Prices used in calculating PV-10 Value:			
$/Bbl (Oil)	$ 76.80	$ 58.63	$ 44.15
$/Mcf	$ 4.51	$ 3.76	$ 5.33
$/Bbl (NGL)	$ 45.62	$ 31.03	$ 23.59

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

The following is a summary of the standardized measure of discounted net cash flows using methodology provided for in Topic 932 of the Accounting Standards Codification^{tm} (the Codification) implemented by the Financial Accounting Standards Board (FASB), related to our estimated proved oil and natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves for the years ended December 31, 2010 and 2009, were computed using benchmark prices based on the unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas during each month of 2010, as required by SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*, effective December 31, 2009, while estimated cash flows in the reserve reports at December 31, 2008, were based on oil and natural gas spot prices as of the end of the period presented. Future development and production costs attributable to the proved reserves were estimated assuming that existing conditions would continue over the economic lives of the individual leases and costs were not escalated for the future. Estimated future income tax expenses were calculated by applying future statutory tax rates (based on the current tax law adjusted for permanent differences and tax credits) to the estimated future pretax net cash flows related to proved oil and natural gas reserves, less the tax basis of the properties involved. Future income tax expenses increased in 2010 because net operating loss carryforward was used to offset capital gains realized in the property divestitures and also due to a decrease in net operating loss carryforwards related to Internal Revenue Code Section 382 limitation by approximately $17.0 million net operating loss adjustment, leaving less net operating loss carryforward available for future years. Additionally, future development costs are less than the previous year. 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, 2010, 2009 and 2008, please review Note M in the notes to our year-end 2010 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,		
	2010	**2009**	**2008**
	(In thousands)		
Future cash inflows	$ 1,355,233	$ 1,314,714	$ 1,253,537
Future production costs	(548,638)	(535,784)	(472,191)
Future development costs	(117,860)	(148,956)	(145,086)
Future income tax expenses	(161,736)	(123,943)	(103,434)
Future net cash flows	526,999	506,031	532,826
10% annual discount for estimated timing of cash flows	(248,952)	(231,797)	(248,373)
Standardized measure of discounted future net cash flows	$ 278,047	$ 274,234	$ 284,453

We believe that the presentation of the PV-10 value is relevant and useful to investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes, and it is a useful measure of evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. However, PV-10 value is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 value measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves as of the specified dates.

The following table provides a reconciliation of our PV-10 Value to our standardized measure:

	At December 31,		
	2010	2009 (In thousands)	2008
PV-10 Value	$ 364,248	$ 336,053	$ 322,131
Future income taxes	(161,736)	(123,943)	(103,434)
Discount of future income taxes at 10% per annum	75,535	62,124	65,756
Standardized Measure	$ 278,047	$ 274,234	$ 284,453

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.

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,		
	2010	2009	2008
Production volumes:			
Oil (MBbls)	995	1,138	1,187
Natural gas liquids (MBbls)	364	406	354
Natural gas (MMcf)	4,816	5,994	6,082
Total (MBoe)	2,161	2,542	2,554
Average realized prices (before effects of derivative contracts):			
Oil (per Bbl)	$ 76.95	$ 58.24	$ 98.59
Natural gas liquids (per Bbl)	38.89	27.26	50.24
Natural gas (per Mcf)	4.21	3.47	7.87
Total per Boe	51.36	38.62	71.52
Effect of settlement of derivative contracts:			
Oil (per Bbl)	$ (6.14)	$ 4.94	$ (8.84)
Natural gas liquids (per Bbl)			
Natural gas (per Mcf)	0.19	2.27	
Total per Boe	(2.40)	7.57	(4.10)
Average realized prices (after effects of derivative contracts):			
Oil (per Bbl)	$ 70.81	$ 63.18	$ 89.75

Natural gas liquids (per Bbl)	38.89	27.26	50.24
Natural gas (per Mcf)	4.40	5.74	7.87
Total per Boe	48.96	46.19	67.42
Expenses (per Boe):			
Oil and natural gas production taxes	$ 2.81	$ 2.09	$ 4.10
Oil and natural gas production expenses	15.68	14.73	14.89
Amortization of full cost pool	12.11	12.06	17.89
General and administrative	6.85	6.56	7.95
Cash interest	8.32	5.28	10.11
Cash taxes	0.18	0.12	0.27
Impairment		18.73	105.66

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Fields containing 15% or more of total proved reserves at December 31, 2010:

	Year Ended December 31,		
	2010	2009	2008
La Copita:			
Production volumes:			
Oil (MBbls)	41	58	42
Natural gas liquids (MBbls)	126	118	112
Natural gas (MMcf)	1,682	1,586	1,670
Total (MBoe)	447	441	433
Average realized prices:			
Oil (per Bbl)	$ 76.65	$ 58.41	$ 103.45
Natural gas liquids (per Bbl)	39.89	29.28	46.36
Natural gas (per Mcf)	4.32	3.95	8.91
Total per Boe	34.49	29.78	56.47
Oil and natural gas production expenses (per Boe)	$ 4.31	$ 3.62	$ 4.68

	Year Ended December 31,		
	2010	2009	2008
Electra/Burkburnett:			
Production volumes:			
Oil (MBbls)	471	537	560
Natural gas liquids (MBbls)	41	70	91
Natural gas (MMcf)			
Total (MBoe)	512	607	651
Average realized prices:			
Oil (per Bbl)	$ 77.24	$ 57.99	$ 99.05
Natural gas liquids (per Bbl)	55.67	27.85	42.22
Natural gas (per Mcf)			
Total per Boe	75.49	54.51	91.15
Oil and natural gas production expenses (per Boe)	$ 28.21	$ 22.46	$ 22.71

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,		
	2010	2009	2008
Proved property acquisition costs	$ 1,133	$ 1,311	$ 10,091
Unproved property acquisition costs			2,691
Development costs	27,850	28,239	57,084
Exploration costs	4,552	321	14,857

Total costs incurred	$ 33,535	$ 29,871	$ 84,723

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. Most of our drilling in 2010 was in our mature fields on proved undeveloped properties, which does not result in significant reserve additions. Because in 2010 we had no significant acquisitions of producing properties, discoveries were limited and no significant reserves were added, our finding cost in 2010 was substantially greater per Boe as compared to prior years. Our three-year average finding cost was $15.62 per Boe.

	Year Ended December 31,		
	2010	2009	2008
Proved reserves acquired/discovered (MBoe)	545	3,957	4,984
Total cost per Boe of reserves acquired/discovered	$ 61.53	$ 7.55	$ 17.00

Producing Wells

The following table sets forth the number of productive wells in which we owned an interest as of December 31, 2010. 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	2,624	2,124.7
Natural gas	604	329.4
Total	3,228	2,454.1

Acreage

The following table sets forth our developed and undeveloped gross and net leasehold acreage as of December 31, 2010:

	Gross	Net
Developed	111,969	60,298
Undeveloped	178,782	59,671
Total	290,751	119,969

Approximately 44% of our net acreage was located in our core areas as of December 31, 2010. 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,					
	2010(1)		2009(2)		2008(3)	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	59	51	45	44	83	66.8
Non-productive			1	0.9	1	0.2
Exploratory wells:						
Productive	3	3			6	5.1
Non-productive	1	0.2				
Total	63	54.2	46	44.9	90	72.1

(1) Does not include seven gross (5.8 net) wells that were in the process of being completed at December 31, 2010, and does include three gross (0.2 net) wells that were drilled in 2009 and waiting on pipeline connection.

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

(3) Does not include seven gross (5.8 net) wells that were in the process of being completed at December 31, 2008.

Divestitures

On December 8, 2010, we completed the sale to Milagro Producing, LLC, a privately owned company located in Houston, Texas, of all of our oil and natural gas properties and related assets located in the Boonsville and Newark East fields of Jack and Wise Counties, Texas. The effective date of the sale was October 1, 2010. The sale properties included all of our Bend Conglomerate shallow gas properties and all of our North Texas Barnett Shale properties, including both producing properties and undeveloped leasehold. We received net cash proceeds at closing of $42.3 million subject to customary post-closing adjustments. As of December 31, 2010, net proceeds including post-closing adjustments were $41.0 million. Proved reserves from these properties accounted for approximately 26.4 billion cubic feet equivalent (Bcfe) of natural gas, natural gas liquids and oil, or an estimated 13% of our year-end 2009 proved reserves of 204 Bcfe.

On December 30, 2010, we closed the sale of certain non-operated natural gas properties located in eastern Oklahoma for $8.0 million (prior to closing adjustments). The effective date of the sale was December 1, 2010. Our full cost pool at December 31, 2010 was reduced by the net proceeds, including closing adjustments, of $7.8 million in accordance with the full cost method of accounting. The proceeds were used to reduce outstanding borrowings under our revolving credit facility.

Oil and Natural Gas Marketing and Derivative Activities

During the year ended December 31, 2010, Shell Trading (US) Company, or STUSCO, accounted for $68.1 million, or 61%, of our oil and natural gas revenue for that period. No other purchaser accounted for 10% or more of our oil and natural gas revenue during 2010. Our agreement with STUSCO covers all of our North Texas oil production. Effective August 1, 2008 through January 31, 2009, our agreement provided for payment, on a per barrel basis, of a price equal to STUSCO s posted price for North Texas Sweet plus a premium of $3.25. Effective during the period February through June 2009, our contract price was revised to STUSCO North Texas Sweet, plus or minus Platt s P-Plus Posting, minus $1.50. (Note: the P-Plus posted price is a fluctuating premium based on the NYMEX front-month, second-month, and third-month rolls. Shifts in the NYMEX forward curve are relative to fundamental market conditions such as petroleum stock levels at

Cushing and refinery demand.) For the period July 2009 through June 2010, our contract price was revised to STUSCO s posted price for West Texas Intermediate (WTI) plus $0.80. Effective for the period of July through December 2010, the contract price was renegotiated to STUSCO WTI plus $1.30.

We are also subject to a crude purchase contract with STUSCO covering all of our oil production in our Fitts and Allen fields in Oklahoma. Effective January through February 2010, our contract price was Sunoco s posted price for Oklahoma Sweet plus $0.25. Effective March through June 2010, our contract price increased to Sunoco OK Sweet plus $0.85, and effective July through December 2010, our price was renegotiated to Sunoco OK Sweet plus $1.15.

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. 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, 2010.

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. We also have an executive and operating office at 4965 Preston Park Blvd., Suite 800, in Plano, Texas, subject to a lease extending through 2013. Currently, rent under the lease is approximately $0.7 million annually. We have subleased a portion of our Plano office and will receive approximately $0.1 million annually. We also lease a small office in Houston, Texas. We believe that our facilities are adequate for our current needs.

Regulation

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

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

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

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

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

In December 2009, the EPA promulgated a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas (GHG) regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, in

September 2009 and December 2010, the EPA also promulgated a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. These regulations may apply to our operations. The EPA has promulgated two other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and which will likely affect sources in the oil and gas exploration and production industry and pipeline industry.

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

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

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

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

Employees

At December 31, 2010, we had 206 employees, of whom 42 were administrative, accounting or financial personnel and of whom 164 were technical and operations personnel. Our exploration staff includes three exploration geologists and six landmen. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreement and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Available Information

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

Item 3. ***Legal Proceedings***

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are not currently 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.

Item 4. ***Reserved***

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**
2011:		
First Quarter (through March 14, 2011)	$ 2.45	$ 1.56
2010:		
First Quarter	$ 2.23	$ 1.40
Second Quarter	2.30	1.49
Third Quarter	2.17	1.37
Fourth Quarter	1.92	1.38
2009:		
First Quarter	$ 1.24	$ 0.40
Second Quarter	1.09	0.68
Third Quarter	1.30	0.64
Fourth Quarter	2.24	1.41
2008:		
First Quarter	$ 5.10	$ 4.42
Second Quarter	6.73	4.80
Third Quarter	6.40	2.68
Fourth Quarter	2.75	0.74

Holders

As of March 7, 2011, there were 98 holders of record of our common stock. We believe that at March 7, 2011, there were 5,921 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. In addition, our credit facilities do not permit us to pay dividends on our common stock.

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Compensation Plan Information

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2010, 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)			1,960,271(2)
Equity compensation plans not approved by security holders			
Total			1,960,271

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

(2) This number reflects shares available for issuance under our 2006 Long-Term Incentive Plan as of December 31, 2010.

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Stockholder Return Performance Presentation

The following graph and table compare the cumulative 5-year total return provided to our stockholders on our common stock beginning December 31, 2005, through December 31, 2010, relative to the cumulative total returns of the Nasdaq Composite index and the Dow Jones Wilshire MicroCap Exploration & Production index. The comparison assumes an investment of $100 (with reinvestment of all dividends) was made in our common stock on December 31, 2005, and in each of the indexes and its relative performance is tracked through December 31, 2010. The identity of the 50+ companies included in the Dow Jones Wilshire MicroCap Exploration & Production Index will be provided upon request.

COMPARISON OF 5 YEAR CUMULATIVE TOTL RETURN*
Among RAM Energy Resources, Inc., the NASDAQ Composite Index
and a Peer Group

	Year Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
RAM Energy Resources, Inc.	$ 33	$ 37	$ 16	$ 91	$ 100
Nasdaq Composite	126	107	74	125	111
Dow Jones Wilshire MicroCap Exploration & Production Index	64	41	30	67	83

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Item 6. *Selected Financial Data*

We acquired RAM Energy, Inc. 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 2010, 2009, 2008 and 2007 may not be comparative to other periods as a result of certain divestitures and acquisitions, as more fully described in our consolidated financial statements included elsewhere in this report.

Selected Financial Data
(In thousands, except share data)

	Year Ended December 31,				
	2010	**2009**	**2008**	**2007(1)**	**2006**
Revenues and Other Operating Income:					
Oil sales	$ 76,563	$ 66,281	$ 117,036	$ 55,000	$ 48,013
Natural gas sales	20,265	20,818	47,884	17,830	14,232
Natural gas liquids sales	14,156	11,068	17,770	9,047	5,770
Realized gains (losses) on derivatives	(5,193)	19,255	(10,472)	(2,669)	(4,650)
Unrealized gains (losses) on derivatives	6,386	(30,561)	33,257	(10,056)	6,239
Other	157	217	382	488	640
Total revenues and other operating income	112,334	87,078	205,857	69,640	70,244
Operating Expenses:					
Oil and natural gas production taxes	6,063	5,320	10,480	4,869	3,329
Oil and natural gas production expenses	33,891	37,455	38,030	21,574	18,266
Depreciation and amortization	27,225	31,650	46,512	18,948	13,252
Accretion expense	1,527	1,976	2,207	704	535
Impairment		47,613	269,886		
Share-based compensation	3,110	2,179	2,563	989	2,308
General and administrative, net of operator s overhead fees	14,799	16,667	20,305	11,891	9,300
Total operating expenses	86,615	142,860	389,983	58,975	46,990

Operating income (loss)	25,719	(55,782)	(184,126)	10,665	23,254
Other Income (Expense):					
Interest expense	(22,655)	(18,590)	(24,182)	(20,757)	(17,050)
Interest income	27	82	208	1,047	309
Other income (expense)	321	(440)	(13,536)	(57)	
Income (Loss) Before Income Taxes	3,412	(74,730)	(221,636)	(9,102)	6,513
Income Tax Provision (Benefit)	995	(16,347)	(91,683)	(7,852)	1,465
Net income (loss)	$ 2,417	$ (58,383)	$ (129,953)	$ (1,250)	$ 5,048

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

Selected Financial Data (continued)
(In thousands, except share data)

	Year Ended December 31, 2010	2009	2008	2007(1)	2006
Cash dividends per share	$	$	$	$	$ 0.02
Earnings (loss) per share:					
Basic	$ 0.03	$ (0.75)	$ (1.80)	$ (0.03)	$ 0.16
Diluted	0.03	(0.75)	(1.80)	(0.03)	0.16
Weighted average shares outstanding:					
Basic	78,426,179	77,601,057	72,234,750	42,087,617	30,900,213
Diluted	78,426,179	77,601,057	72,234,750	42,087,617	32,119,169
Statement of Cash Flow Data					
Cash provided by (used in):					
Operating activities	$ 37,875	$ 32,372	$ 74,454	$ 17,042	$ 29,660
Investing activities	14,970	(23,921)	(82,568)	(241,192)	(25,317)
Financing activities	(52,937)	(8,486)	1,405	224,302	2,308
Other Data					
Capital expenditures(2)	$ 33,535	$ 29,871	$ 84,723	$ 344,795	$ 28,145
Modified EBITDA	50,969	58,287	103,641	42,352	33,419

	As of December 31, 2010	2009	2008	2007(1)	2006
Balance Sheet Data					
Total assets	$ 265,001	$ 311,162	$ 403,964	$ 580,242	$ 161,725
Long-term debt, including current portion	197,092	246,167	250,696	335,747	132,237
Stockholders equity (deficit)	4,167	(526)	57,840	98,698	(27,895)

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

(2) Includes costs of acquisitions.

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

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

We believe that Modified EBITDA is useful to investors to provide disclosure of our operating results on the same basis as that used by our management. We also believe that this measure can assist investors in comparing our performance to that of other companies on a consistent basis without regard to certain items that do not directly affect our ongoing operating performance or cash flows. Modified EBITDA, which is not a financial measure under generally accepted accounting principles, or GAAP, has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for net income, cash flows from operating activities and other consolidated income or cash flows statement data prepared in accordance with GAAP.

Because of these limitations, Modified EBITDA should neither be considered as a measure of discretionary cash available to us to invest in the growth of our business, nor as a replacement for net income. We compensate for these limitations by relying primarily on our GAAP results and using Modified EBITDA as supplemental information.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
			(In thousands)		
Reconciliation of Modified EBITDA to net income (loss):					
Net income (loss)	$ 2,417	$ (58,383)	$ (129,953)	$ (1,250)	$ 5,048
Plus: Interest expense	22,655	18,590	24,182	20,757	17,050
Plus: Amortization and depreciation expense	27,225	31,650	46,512	18,948	13,252
Plus: Accretion expense	1,527	1,976	2,207	704	535
Plus: Income tax expense (benefit)	995	(16,347)	(91,683)	(7,852)	1,465
Plus: Share-based compensation	3,110	2,179	2,563	989	2,308
Plus: Impairment charges		47,613	269,886		
Plus: Settlement charge	(574)	448	13,184		
Plus: Unrealized (gain) loss on derivatives	(6,386)	30,561	(33,257)	10,056	(6,239)
Modified EBITDA	$ 50,969	$ 58,287	$ 103,641	$ 42,352	$ 33,419

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

General

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

On December 8, 2010, we completed the sale to Milagro Producing, LLC, a privately owned company located in Houston, Texas, of all of our oil and natural gas properties and related assets located in the Boonsville and Newark East fields of Jack and Wise Counties, Texas. The effective date of the sale was October 1, 2010. The sale properties included all of our Bend Conglomerate shallow gas properties and all of our North Texas Barnett Shale properties, including both producing properties and undeveloped leasehold. We received net cash proceeds at closing of $42.3 million subject to customary post-closing adjustments. As of December 31, 2010, net proceeds including post-closing adjustments were $41.0 million. Proved reserves from these properties accounted for approximately 26.4 billion cubic feet equivalent (Bcfe) of natural gas, natural gas liquids and oil, or an estimated 13% of our year-end 2009 proved reserves of 204 Bcfe. Information as to our recent divestitures is set forth under Note B to the Consolidated Financial Statements.

Oil and natural gas prices have historically been volatile. In 2010, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $76.95 per Bbl and $4.21 per Mcf, respectively, a significant improvement over 2009 average realized prices of $58.24 per Bbl and $3.47 per Mcf, respectively. A significant decline in annual average prices for oil and natural gas began during the last half of 2008. Spot natural gas prices declined to $5.71 per Mcf on December 31, 2008, from $12.27 per Mcf on June 30, 2008, a decrease of approximately 53%. Oil prices in the last six months of 2008 experienced a 68% decrease, declining to $44.60 per Bbl on December 31, 2008, from $138.32 per Bbl on June 30, 2008. Natural gas and oil prices continued to decline into the first quarter of 2009. Prices improved in the fourth quarter of 2009 for oil, increasing 28% to $73.36 per Bbl compared to $57.56 in the 2008 period. Natural gas prices continued to decline to $3.93 per Mcf in the fourth quarter of 2009 from $5.05 in the fourth quarter of

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2008, a 22% drop. It is impossible to predict the frequency, duration or outcome of any volatile price movements or the long-term impact on drilling and operating costs and the impacts, whether favorable or unfavorable, to our results of operations and liquidity. We continue to monitor operations and planned capital budget expenditures as the economics of many projects may diminish as a result of prolonged natural gas price declines.

Critical Accounting Policies

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

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

Under the full cost method the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed the estimated after-tax future net revenues from proved oil and natural gas properties, discounted at 10% (the Ceiling Limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, and certain production-related and ad valorem taxes are deducted. In calculating future net revenues, prices and costs are held constant indefinitely, except for changes that are fixed and determinable by existing contracts. The net book value is compared to the Ceiling Limitation on a quarterly and yearly basis. The excess, if any, of the net book value above the Ceiling Limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. At December 31, 2008, the net book value of our oil and natural gas properties exceeded the Ceiling Limitation resulting in reduction in the carrying value of our oil and natural gas properties by $269.4 million, or $171.6 million net of tax, and at March 31, 2009, the net book value of our oil and natural gas properties exceeded the Ceiling Limitation resulting in reduction in the carrying value of our oil and natural gas properties by $47.6 million, or $30.3 million net of tax. We incurred no impairment charge in 2010.

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

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

- Revises a number of definitions relating to proved oil and natural gas reserves to make them consistent with the Petroleum Resource Management System, which includes certain non-traditional resources in proved reserves;

Permits the use of new technologies for determining proved oil and natural gas reserves;

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- 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 primary responsibility for preparing the reserve estimates.

Our independent petroleum engineers utilized the new procedures in preparing the estimate of our proved reserves as of December 31, 2009 and 2010, as reflected in this report.

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

As set forth in Topic 740 of the Codification, deferred income taxes are recognized at each period end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. We routinely assess the realizability of our deferred tax assets. We consider future taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods.

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

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

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

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

New Accounting Pronouncements

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

In January 2009, the FASB issued guidance on fair value disclosures to enhance disclosures surrounding the transfers of assets in and out of Level 1 and Level 2, to present more detail surrounding asset activity for Level 3 assets and to clarify existing disclosure requirements. The new guidance is set forth in Topic 820 of the Codification and is effective for us beginning January 1, 2010. Additional disclosure about purchases, sales, issuances, and settlement in the roll forward of activity in Level 3 fair value measurements is effective beginning January 1, 2011. Adoption of the guidance on January 1, 2010 did not, and adoption of the guidance on January 1, 2011 will not, have any impact our financial position or statement of operations.

In February 2010, the FASB issued an update to authoritative guidance, as set forth in Topic 855 of the Codification, relating to subsequent events, which was effective upon the issuance of the update. We adopted this authoritative guidance during the first quarter of 2010. The update removes the requirement for U.S. Securities and Exchange Commission filers to disclose the date through which subsequent events have been evaluated in both issued and revised financial statements. The adoption of this update did not impact our financial position or statement of operations other than removing the disclosure.

In December 2010, the FASB issued an update to authoritative guidance, as set forth in Topic 805 of the Codification, relating to business combinations. This update provides clarification requiring public companies that have completed material acquisitions to disclose the revenue and earnings of the combined business as if the acquisition took place at the beginning of the comparable prior annual reporting period, and also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, non-recurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We will be required to apply this guidance prospectively for business

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combinations for which the acquisition date is on or after January 1, 2011. We do not expect the adoption of this new guidance to have a material impact on our financial position or statement of operations.

Results of Operations

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

As we concentrate our holdings into areas that align with our objectives, we have determined to report our operations by state, rather than by field as was reported in previous years. The following tables summarize our oil and natural gas production volumes, average sale prices and comparisons for the years ended December 31, 2010 and 2009:

	Texas	Oklahoma	Louisiana	Other	Total
Year Ended December 31, 2010					
Aggregate Net Production					
Oil (MBbls)	559	322	79	35	995
NGLs (MBbls)	341	10		13	364
Natural Gas (MMcf)	3,128	849	689	150	4,816
MBoe	1,421	473	194	73	2,161
Year Ended December 31, 2009					
Aggregate Net Production					
Oil (MBbls)	664	356	83	35	1,138
NGLs (MBbls)	375	15		16	406
Natural Gas (MMcf)	3,821	1,266	743	164	5,994
MBoe	1,676	582	207	77	2,542
Change in MBoe	(255)	(109)	(13)	(4)	(381)
Percentage Change in MBoe	(15.2)%	(18.7)%	(6.3)%	(5.2)%	(15.0)%

	Year Ended December 31, 2010	Year Ended December 31, 2009	Increase
Average sale prices:			
Oil (per Bbl)	$ 76.95	$ 58.24	32.1%
NGL (per Bbl)	$ 38.89	$ 27.26	42.7%
Natural gas (per Mcf)	$ 4.21	$ 3.47	21.3%
Per Boe	$ 51.36	$ 38.62	33.0%

Oil and natural gas sales increased $12.8 million, or 13%, to $111.0 million for the year ended December 31, 2010, as compared to $98.2 million for the year ended December 31, 2009. This increase was driven by commodity price increases on a per Boe basis of 33% for the year ended December 31, 2010, as compared to 2009.

Production volumes decreased 15% overall during the year ended December 31, 2010, as compared to the year ended December 31, 2009, primarily due to natural production declines and weather-related interruptions. Production from our Texas fields decreased by 255 MBoe in the current year.

Drilling activity in our Texas fields included 58 gross (51.1 net) wells in 2010, all of which were completed as producing wells, and three gross (3.0 net) wells in the process of being completed at December 31, 2010. Production from our Oklahoma fields decreased by 109 MBoe over the prior year. Drilling activity in our Oklahoma fields included three gross (2.9 net) wells, all of which were completed as producing, and three gross (2.8 net) wells waiting on completion at December 31, 2010. Production from our Louisiana fields decreased by 13 MBoe over the prior year. Drilling activity in our Louisiana fields included one gross (0.2 net) well, which was a dry hole, in 2010. Lower development capital expenditures resulted in decreased production in 2010 from natural production declines not offset by increased drilling. After adjusting our 2010 production by the contribution made by the properties sold in December 2010, we expect production from our remaining properties to remain relatively constant in 2011 with the exception of South Texas which is mainly gas and will continue to have declining production until prices improve.

The average realized sales price for oil was $76.95 per barrel for the year ended December 31, 2010, an increase of 32%, compared to $58.24 per barrel for 2009. The average realized sales price for NGLs was $38.89 for the year ended December 31, 2010, an increase of 43%, compared to $27.26 per barrel for 2009. The average realized sales price for natural gas was $4.21 per Mcf for the year ended December 31, 2010, an increase of 21%, compared to $3.47 per Mcf for 2009.

Realized and Unrealized Gain (Loss) from Derivatives. For the year ended December 31, 2010, our gain from derivatives was $1.2 million compared to a loss of $11.3 million for the year ended December 31, 2009. 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. The significant shift from 2009 to 2010 was primarily a result of higher market prices in the 2010 period.

	Year Ended December 31, 2010	Year Ended December 31, 2009
	(In thousands)	
Contract settlements and premium costs:		
Oil	$ (6,110)	$ 5,626
Natural gas	917	13,629
Realized gains (losses)	(5,193)	19,255
Mark-to-market gains (losses):		
Oil	4,817	(23,724)
Natural gas	1,569	(6,837)
Unrealized gains (losses)	6,386	(30,561)
Realized and unrealized gains (losses)	$ 1,193	$ (11,306)

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $6.1 million for the year ended December 31, 2010, compared to $5.3 million for the year ended December 31, 2009, due primarily to higher commodity prices during the 2010 period. Production taxes vary by state. Most are based on realized prices at the wellhead, while Louisiana production tax is based on volumes for natural gas and value for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 5% for the year ended December 31, 2010 and 2009.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $33.9 million for the year ended December 31, 2010, a decrease of $3.6 million, or 10%, from the $37.5 million for the year ended

December 31, 2009, due primarily to cost-saving measures implemented in 2010. For the year ended December 31, 2010, our oil and natural gas production expense was $15.68 per Boe compared to $14.73 per Boe for the year ended December 31, 2009, an increase of 6%.

Depreciation and Amortization Expense. Our depreciation and amortization expense decreased $4.4 million, or 14%, for the year ended December 31, 2010, compared to the year ended December 31, 2009. The decrease was a result of a decrease in production during 2010, partially offset by a higher depletion rate per Boe. On an equivalent basis, our amortization of the full-cost pool of $26.2 million was $12.11 per Boe for the year ended December 31, 2010, an increase of less than 1% per Boe compared to $30.7 million, or $12.06 per Boe for the year ended December 31, 2009.

Accretion Expense. Topic 410 of the Codification includes, among other things, the accounting for asset retirement obligations. Accretion expense is a function of changes in the discounted liability from period to period. We recorded $1.5 million for the year ended December 31, 2010, compared to $2.0 million for the year ended December 31, 2009.

Impairment Charge. For the year ended December 31, 2010, we incurred no impairment charges. We incurred a $47.6 million impairment on the carrying value of our oil and gas properties for the year ended December 31, 2009. The impairment of our oil and gas properties was primarily due to a reduction in the tax affected estimated present value of future net revenues, caused by dramatic decline in natural gas prices, from our proved oil and gas reserves between December 31, 2008, and March 31, 2009.

Share-Based Compensation. From time to time, our board of directors grants restricted stock awards under our 2006 Long-Term Incentive Plan. Each of these grants vests in equal increments over the vesting period provided for the particular award. All currently unvested awards provide for vesting periods of from one to five years. The share-based compensation expense related to these grants is calculated using the closing price per share on each of the grant dates and the total share-based compensation on all these grants will be recognized over their respective vesting periods. For the year ended December 31, 2010, we recorded a total of $3.1 million share-based compensation expense compared to $2.2 million for the year ended December 31, 2009. The increase in share-based compensation expense was primarily due to additional grants and increased stock price during the 2010 period.

General and Administrative Expense. For the year ended December 31, 2010, our general and administrative expense was $14.8 million, compared to $16.7 million for the year ended December 31, 2009, a decrease of $1.9 million, or 11%. The decrease is primarily due to decreased professional fees and lower employee-related costs in 2010.

Interest Expense. We recorded interest expense of $22.7 million for the year ended December 31, 2010, compared to $18.6 million incurred during the previous year. Interest rates were higher in 2010 compared to 2009 due to the Second Amendment to our credit facility executed June 26, 2009. Our blended interest rate was 8.0% during 2010 compared to 7.6% in the 2009 period. As a result of higher interest rates for the period, our interest expense increased by $4.1 million for the year ended December 31, 2010, compared to 2009.

Other Income (Expense). Our other income was $0.3 million in 2010 compared to other expense of $0.4 million in 2009. For the year ended December 31, 2010, we reduced a contingency accrual by $0.6 million related to settlement of pending litigation offset by a charge relating to pipe inventory write-off. For the year ended December 31, 2009, we recorded $0.4 million charge to other expense primarily for expenses related to settlement of pending litigation.

Income Taxes. For the year ended December 31, 2010, we recorded an income tax provision of $1.0 million on a pre-tax income of $3.4 million. The income tax provision for 2010 included a $5.7 million decrease to deferred tax assets under Section 382 of the Internal Revenue Code related to net operating loss limitations and a decrease in the valuation allowance of $6.6 million for revisions to future taxable income projections. For the year ended December 31, 2009, we recorded an income tax benefit of $16.3 million on a pre-tax loss of $74.7 million. Included in the income tax benefit for 2009 is an increase in valuation allowance of $9.5 million to reflect our estimate of reduced tax benefits expected to be realized from net deferred tax assets of the company. The effective tax rates for the year ended December 31, 2010 and 2009, were 29.2% and 21.9%, respectively.

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

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

	Texas	Oklahoma	Louisiana	Other	Total
Year Ended December 31, 2009					
Aggregate Net Production					
Oil (MBbls)	664	356	83	35	1,138
NGLs (MBbls)	375	15		16	406
Natural Gas (MMcf)	3,821	1,266	743	164	5,994
MBoe	1,676	582	207	77	2,542
Year Ended December 31, 2008					
Aggregate Net Production					
Oil (MBbls)	683	406	54	44	1,187
NGLs (MBbls)	338	14		2	354
Natural Gas (MMcf)	4,039	1,050	730	263	6,082
MBoe	1,693	595	176	90	2,554
Change in MBoe	(17)	(13)	31	(13)	(12)
Percentage Change in MBoe	(1.0)%	(2.2)%	17.6%	(14.4)%	(0.5)%

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

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

Production volumes were essentially flat during the year ended December 31, 2009, as compared to the year ended December 31, 2008. Texas production included our Boonsville and Barnett Shale fields, both in North Texas, which increased by 67 MBoe and 74 MBoe, respectively, in 2009 as compared to the prior year. Drilling activity in 2009 included one gross (one net) well in Boonsville and two gross (0.4 net) wells on our Tier 1 Barnett Shale acreage, with one gross (0.4 net) well completed as a producing well and one gross (0.04 net) well in the process of being completed at December 31, 2009. Offsetting production declines included our Electra/Burkburnett field in North Texas and our South Texas field, which decreased by 44 MBoe and 59 MBoe, respectively, in 2009 as compared to 2008 primarily as a result of normal production declines and a reduced pace of drilling in those fields. We drilled 39 gross (39.0 net) wells in Electra/Burkburnett in 2009.

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

Realized and Unrealized Gain (Loss) from Derivatives. For the year ended December 31, 2009, our loss from derivatives was $11.3 million compared to a gain of $22.8 million for the year ended December 31,

2008. Our gains and losses for these periods were the net result of recording actual contract settlements, the premiums paid for our derivative contracts, and unrealized gains and losses attributable to mark-to-market values of our derivative contracts at the end of the periods.

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

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $5.3 million for the year ended December 31, 2009, compared to $10.5 million for the year ended December 31, 2008, due primarily to lower commodity prices during the 2009 period. Production taxes vary by state. Most are based on realized prices at the wellhead, while Louisiana production tax is based on volumes for natural gas and value for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 5% for the year ended December 31, 2009, compared to 6% for the year ended December 31, 2008.

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

Depreciation and Amortization Expense. Our depreciation and amortization expense decreased $14.9 million, or 32%, for the year ended December 31, 2009, compared to the year ended December 31, 2008. The decrease was a result of a lower amortization rate per Boe. On an equivalent basis, our amortization of the full-cost pool of $30.7 million was $12.06 per Boe for the year ended December 31, 2009, a decrease per Boe of 33% compared to $45.7 million, or $17.89 per Boe for the year ended December 31, 2008. This rate decrease per Boe resulted from lower capitalized costs subsequent to the asset impairment writedowns in the fourth quarter of 2008 and the first quarter of 2009.

Accretion Expense. Topic 410 of the Codification includes, among other things, the accounting for asset retirement obligations. Accretion expense is a function of changes in the discounted liability from period to period. We recorded

$2.0 million for the year ended December 31, 2009, compared to $2.2 million for the year ended December 31, 2008.

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

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

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

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

Other Expense. Our other expense was $0.4 million in 2009 compared to $13.5 million in 2008. In 2008, we recorded a charge to other expense of $13.5 million for litigation expense related to a legal settlement. In September 2008, we entered into an agreement pursuant to which we agreed to pay $16.0 million in settlement of a pending class action lawsuit. We placed that amount in escrow in October 2008 in anticipation of a final court approved settlement in the second quarter of 2009. In conjunction with our May 8, 2006 acquisition of RAM Energy, the former stockholders of RAM Energy deposited in escrow 3,200,000 shares of their common stock to secure their potential indemnity obligations to us, including any loss we might sustain in this litigation or through an agreed settlement. At December 31, 2008, we recorded a contingent liability of $16.0 million for the settlement and a receivable of $2.8 million representing the market value of the escrow shares based on the closing price of $0.88 per share on December 31, 2008. The $13.5 million charge to other expense represents the difference between the settlement liability and the value of the escrowed shares. On March 5, 2009, the court approved the settlement and on April 6, 2009, the settlement became final. We recorded a $0.4 million charge to other expense in the first quarter of 2009 representing the adjustment to fair market value of the escrowed shares on the final settlement date of $0.74 per share.

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

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Liquidity and Capital Resources

As of December 31, 2010, we had $28.5 million of nominal availability under our revolving credit facility; however, because of the amount of our Modified EBITDA for the preceding four fiscal quarters, the leverage ratio financial covenant in our old credit facility limited us to $23.7 million of additional borrowings as of December 31, 2010. In March 2011, we entered into new credit facilities including a $250.0 million first lien revolving credit facility with an initial $150.0 million borrowing base and a $75.0 million second lien term loan facility. Under our new credit facilities, through September 30, 2011, additional borrowings will not be limited by the leverage ratio covenant in our revolving loan agreement provided our Modified EBITDA for the preceding four fiscal quarters exceeds $47.4 million. Our Modified EBITDA for the four fiscal quarters ending December 31, 2010 was $51.0 million. Management believes that borrowings currently available to us under our credit facilities and anticipated cash flows from operations will be sufficient to satisfy our currently expected capital expenditures, working capital, and debt service obligations through 2011. At December 31, 2010, we had $197.1 million of indebtedness outstanding, including $116.5 million under our revolving credit facility, $80.2 million under our term loan facility and $0.4 million in other indebtedness. As of December 31, 2010, we had an accumulated deficit of $214.9 million and a working capital deficit of $12.4 million.

New Credit Facilities. In March 2011, we entered into new credit facilities. The new facilities, which replaced our previous facility, include a $250.0 million first lien revolving credit facility and a $75.0 million second lien term loan facility. SunTrust Bank is the administrative agent for the revolving facility, and Guggenheim Corporate Funding, LLC is the agent for the term loan facility. The initial borrowing base under the revolving credit facility at the closing is $150.0 million. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the five-year term of the revolver, and initially bear interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The term loan portion of our credit facility provides for payments of interest only during its 5.5-year term, with the initial interest rate being LIBOR plus 9.0% with a 2.0% LIBOR Floor, or if any period we elect to pay a portion of the interest under our term loan in kind, then the interest rate will be LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to principal.

Advances under our credit facilities are secured by liens on substantially all of our properties and assets. The credit facilities contain representations, warranties and covenants customary in transactions of this nature, including restrictions on the payment of dividends on our capital stock and financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to total indebtedness. We are required to maintain commodity hedges on a rolling basis for the first 12 months out with respect to not less than 60%, but not more than 85%, and for the next 18 months out with respect to not less than 50% but not more than 85%, of our projected quarterly production volumes, until the leverage ratio is less than or equal to 1.5 to 1.0. At December 31, 2010, our commodity hedging represented approximately 56% of our projected production volumes through June 30, 2013.

Our previous credit facility entered into November 2007 included a $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. This facility included 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 our previous revolving credit facility was $145.0 million at December 31, 2010. Funds advanced under the revolving credit facility initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The term loan portion of our credit facility initially provided for payments of interest only during its five-year term, with the initial interest rate being LIBOR plus 7.5%.

On June 26, 2009, we renegotiated certain terms of our previous credit facility to provide us greater flexibility in complying with certain of the financial covenants under the loan agreement. In exchange for the added flexibility afforded by these changes to the credit facility, we agreed to increase the base cash interest rate on both the revolving credit facility and the term loan credit facility by 1.0% per annum, establish a LIBOR floor of 1.5% and pay an additional 2.75% per annum of non-cash, payment-in-kind, or PIK, interest on the term portion of the facility. Accrued PIK interest was added to the principal balance of the term loan on a monthly basis and was paid in connection with the closing of the new credit facilities in March 2011.

In May of 2008, we used $86.6 million in realized net proceeds from the exercise of 17,617,331 warrants to pay down the term facility to $113.4 million. In 2010 and 2009, we used $33.8 million and $4.0 million, respectively, in proceeds from asset sales to pay down the term facility. PIK interest of $1.6 million was added to the term facility in 2009, and PIK interest of $3.0 million was added to the term facility in 2010, bringing the balance to $80.2 million at December 31, 2010.

Our ability to comply with the financial covenants in our new credit facilities may be affected by events beyond our control and, as a result, in future periods we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit facilities. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit facilities. 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, 2010, we were in compliance with all of the financial covenants under our 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, 2010, our net income was $2.4 million, as compared to a net loss of $58.4 million for the year ended December 31, 2009. 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 $35.5 million for the year ended December 31, 2010, compared to $102.4 million for the year of 2009, a decrease of $66.9 million. Asset impairment charge, depreciation and amortization, legal contingency expense and change in unrealized (gains) losses, offset by change in deferred income taxes caused most of this decrease. Working capital changes for the year ended December 31, 2010, were a negative $0.05 million compared with negative changes of $11.7 million for the year ended December 31, 2009. For the year ended December 31, 2010, in total, net cash provided by operating activities was $37.9 million compared to $32.4 million of net cash provided by operations for the previous year.

Cash Flow From Investing Activities. For the year ended December 31, 2010, net cash provided by our investing activities consisted of $49.4 million in proceeds from sales of oil and natural gas properties and other equipment, offset by $34.4 million in payments for oil and gas properties and other equipment. For the year ended December 31, 2009, net cash used in our investing activities was $23.9 million. The change is primarily due to property divestitures in 2010 in conjunction with the execution of our strategic alternative initiative to reduce debt.

Cash Flow From Financing Activities. For the year ended December 31, 2010, net cash used in our financing activities was $52.9 million, compared to net cash used of $8.5 million for the year ended December 31, 2009. The cash used in 2010 included $52.1 million in net payments on long-term debt and $0.8 million for stock withheld to cover employee income taxes on the vesting of stock under our 2006 Long-Term Incentive Plan.

Capital Commitments

During 2010, we had capital expenditures of $33.5 million relating to our oil and natural gas operations, of which $27.9 million was allocated to drilling new development wells and recompletion operations in existing wells, $4.5 million was for exploration costs, and $1.1 million was for acquisition costs.

We have budgeted $35.0 million for non-acquisition capital expenditures in 2011 related to:

developmental drilling and recompletions ($18.0 million);

exploration, including leasehold acquisition, seismic and exploratory drilling ($9.0 million); and

geological, geophysical and contingencies ($8.0 million).

In our 2011 non-acquisition capital budget, we have allocated $8.0 million for continued development of our Electra/Burkburnett area, $2.0 million for drilling on our South Texas properties and $8.0 million for reworking and production enhancement operations in our mature fields, including our Fitts and Allen fields in Oklahoma.

The amount and timing of our capital expenditures for calendar year 2011 may vary depending on a number of factors, including prevailing market prices for oil and natural gas, the favorable or unfavorable results of operations actually conducted, projects proposed by third party operators on jointly owned acreage, development by third party operators on adjoining properties, rig and service company availability, and other influences that we cannot predict.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that cash flows from operations and the availability under our revolving credit facility will be sufficient to satisfy our budgeted non-acquisition capital expenditures, working capital and debt service obligations for 2011. 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 new revolving credit facility matures in March 2016. Our term loan facility matures in September 2016. Should the current tightness in the credit markets continue, future extensions of our credit facilities may contain terms that are less favorable than those of our current credit facility.

Current market conditions also elevate the concern over our cash deposits, which totaled approximately $0.04 million at December 31, 2010, but fluctuate throughout the year, and counterparty risks related to our trade credit. Our cash accounts and deposits with any financial institution that exceed the amount insured by the Federal Deposit Insurance Corporation are at risk in the event one of these financial institutions fails. 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. Nonperformance by a trade creditor could result in losses.

The table below sets forth our contractual cash obligations as of December 31, 2010:

	Total	**2011**	**2012-2013**	**2014-2015**	**and after**
			(In thousands)		
Contractual Cash Obligations					
Long-term debt	$ 197,092	$ 127	$ 167	$ 56	$ 196,742
Operating leases	3,462	1,189	2,213	60	

Total contractual cash obligations	$ 200,554	$ 1,316	$ 2,380	$ 116	$ 196,742

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.

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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, 2010, 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. Under our old credit facility, the impact of a 100-basis point increase in LIBOR interest rates above the then current floor of 1.5% would have resulted in an increase in interest expense of $2.0 million annually based on the $196.7 million balance of our credit facility as of December 31, 2010. A 100-basis point decrease would have had no effect on interest expense until the market rate of LIBOR increased above the then current floor of 1.5%. The new revolving credit facility entered into March 2011 is not subject to LIBOR floors, and the impact of a 100-basis point increase in LIBOR interest rates would have resulted in an increase in interest expense of approximately $1.2 million annually based on the $116.5 million balance of our revolver as of December 31, 2010. LIBOR rates were less than 100-basis points as of December 31, 2010, so any decrease in interest rates would have resulted in a nominal decrease in interest expense under our revolver as of December 31, 2010. The term loan portion of our new credit facility includes a 2.0% LIBOR floor. The impact of a 100-basis point increase in LIBOR rates above our 2.0% floor would result in an increase in interest expense under our term loan of $0.8 million annually based on the $80.2 million balance of our term loan as of December 31, 2010. A 100-basis point decrease would have no effect on interest expense under our term loan until the LIBOR rate exceeds 2.0%.

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 that create potential liability to us covering volumes in excess of our expected production.

Our derivative positions at December 31, 2010, consisting of put/call collars and put options, also called bare floors as they provide a floor price without a corresponding ceiling, are shown in the following table:

	Crude Oil (Bbls)					Natural Gas (Mmbtu)				
	Floors		Ceilings			Floors		Ceilings		
	Per Day(1)	Price	Per Day(1)	Price	Months Covered	Per Day(1)	Price	Per Day(1)	Price	Months Covere
ollars										
011	1,921	$ 80.00	1,921	$ 105.00	April December	6,219	$ 5.00	6,219	$ 9.48	January Septemb
012	995	$ 80.00	995	$ 105.00	January June		$		$	

Bare Floors **Bare Floors**

	Per Day(1)	Price	Months Covered		Per Day(1)	Price	Months Covered	
Year								
2011	1,177	$ 60.00	January	September	1,841	$ 4.18	October	December
2012		$			2,486	$ 4.25	January	March

(1) Per day amounts are calculated based on a 365-day year for 2011 and on a 366-day year for 2012.

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Based on December 31, 2010, NYMEX forward curves of natural gas and crude oil futures prices, adjusted for volatility by 67.5 basis points, we would expect to receive future cash payments of $1.1 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 $7.0 million, and if future prices were to increase by 10%, we would pay future cash payments of $5.6 million.

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
RAM Energy Resources, Inc.

We have audited the accompanying consolidated balance sheets of RAM Energy Resources, Inc. (a Delaware corporation) and subsidiaries (the Company) as of December 31, 2010 and 2009, 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, 2010. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above presently fairly, in all material respects, the consolidated financial position of RAM Energy Resources, Inc. and subsidiaries at December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of RAM Energy Resources, Inc. and subsidiaries internal control over financial reporting as of December 31, 2010, 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 16, 2011 expressed an unqualified opinion on the effective operation of internal control over financial reporting.

/s/ UHY LLP

Houston, Texas
March 16, 2011

RAM Energy Resources, Inc.

Consolidated Balance Sheets
(In thousands, except share and per share amounts)

	As of December 31, 2010	As of December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 37	$ 129
Accounts receivable:		
Oil and natural gas sales, net of allowance of $50 ($50 at December 31, 2009)	9,797	12,585
Joint interest operations, net of allowance of $479 ($641 at December 31, 2009)	631	1,303
Other, net of allowance of $48 ($48 at December 31, 2009)	155	193
Derivative assets	1,340	
Prepaid expenses	1,657	1,970
Deferred tax asset	3,526	3,531
Inventory	3,382	3,900
Other current assets	4	27
Total current assets	20,529	23,638
PROPERTIES AND EQUIPMENT, AT COST:		
Proved oil and natural gas properties and equipment, using full cost accounting	689,472	702,502
Other property and equipment	10,072	9,337
	699,544	711,839
Less accumulated depreciation, amortization and impairment	(489,634)	(462,541)
Total properties and equipment	209,910	249,298
OTHER ASSETS:		
Deferred tax asset	31,001	31,573
Deferred loan costs, net of accumulated amortization of $5,012 ($2,924 at December 31, 2009)	2,609	4,697
Other	952	1,956
Total assets	$ 265,001	$ 311,162
LIABILITIES AND STOCKHOLDERS EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 17,149	$ 15,697
Oil and natural gas proceeds due others	9,414	10,113
Other	452	636
Accrued liabilities:		
Compensation	1,948	2,664
Interest	2,448	2,933

Income taxes	699	655
Other	10	10
Derivative liabilities		4,471
Asset retirement obligations	639	711
Long-term debt due within one year	127	126
Total current liabilities	32,886	38,016
DERIVATIVE LIABILITIES	203	358
LONG-TERM DEBT	196,965	246,041
ASSET RETIREMENT OBLIGATIONS	30,770	26,363
OTHER LONG-TERM LIABILITIES	10	10
COMMITMENTS AND CONTINGENCIES		900
STOCKHOLDERS EQUITY (DEFICIT):		
Common stock, $0.0001 par value, 100,000,000 shares authorized, 82,597,829 and 80,748,674 shares issued, 78,386,983 and 76,951,883 shares outstanding at December 31, 2010 and 2009, respectively	8	8
Additional paid-in capital	226,042	222,979
Treasury stock 4,210,846 shares (3,796,791 shares at December 31, 2009) at cost	(6,976)	(6,189)
Accumulated deficit	(214,907)	(217,324)
Stockholders equity (deficit)	4,167	(526)
Total liabilities and stockholders equity (deficit)	$ 265,001	$ 311,162

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

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RAM Energy Resources, Inc.

Consolidated Statements of Operations
(In thousands, except share and per share amounts)

	Years Ended December 31, 2010	2009	2008
REVENUES AND OTHER OPERATING INCOME:			
Oil and natural gas sales			
Oil	$ 76,563	$ 66,281	$ 117,036
Natural gas	20,265	20,818	47,884
NGLs	14,156	11,068	17,770
Total oil and natural gas sales	110,984	98,167	182,690
Realized gains (losses) on derivatives	(5,193)	19,255	(10,472)
Unrealized gains (losses) on derivatives	6,386	(30,561)	33,257
Other	157	217	382
Total revenues and other operating income	112,334	87,078	205,857
OPERATING EXPENSES:			
Oil and natural gas production taxes	6,063	5,320	10,480
Oil and natural gas production expenses	33,891	37,455	38,030
Depreciation and amortization	27,225	31,650	46,512
Accretion expense	1,527	1,976	2,207
Impairment		47,613	269,886
Share-based compensation	3,110	2,179	2,563
General and administrative, overhead and other expenses, net of operator s overhead fees	14,799	16,667	20,305
Total operating expenses	86,615	142,860	389,983
Operating income (loss)	25,719	(55,782)	(184,126)
OTHER INCOME (EXPENSE):			
Interest expense	(22,655)	(18,590)	(24,182)
Interest income	27	82	208
Other income (expense)	321	(440)	(13,536)
INCOME (LOSS) BEFORE INCOME TAXES	3,412	(74,730)	(221,636)
INCOME TAX PROVISION (BENEFIT)	995	(16,347)	(91,683)
Net income (loss)	$ 2,417	$ (58,383)	$ (129,953)
BASIC INCOME (LOSS) PER SHARE	$ 0.03	$ (0.75)	$ (1.80)
BASIC WEIGHTED AVERAGE SHARES OUTSTANDING	78,426,179	77,601,057	72,234,750
DILUTED INCOME (LOSS) PER SHARE	$ 0.03	$ (0.75)	$ (1.80)

DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING	78,426,179	77,601,057	72,234,750

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

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RAM Energy Resources, Inc.

Consolidated Statements of Stockholders Equity (Deficit)
Years ended December 31, 2010, 2009, and 2008
(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock Shares	Treasury Stock Amount	Accumulated Deficit	Stockholders Equity (Deficit)
BALANCE, January 1, 2008	60,842,836	$ 6	$ 131,625	889,666	$ (3,945)	$ (28,988)	$ 98,698
Long term incentive plan grants	1,104,800						
Long term incentive plan forfeitures	(141,393)						
Net loss						(129,953)	(129,953)
Warrants exercised	17,617,331	2	86,612				86,614
Repurchase of stock				1,774	(82)		(82)
Share-based compensation			2,563				2,563
BALANCE, December 31, 2008	79,423,574	8	220,800	891,440	(4,027)	(158,941)	57,840
Long term incentive plan grants	1,343,000						
Long term incentive plan forfeitures	(17,900)						
Net loss						(58,383)	(58,383)
Repurchase of stock				21,541	(28)		(28)
Receipt of common stock for settlement of contingent receivable				2,883,810	(2,134)		(2,134)
Share-based compensation			2,179				2,179
BALANCE, December 31, 2009	80,748,674	8	222,979	3,796,791	(6,189)	(217,324)	(526)
Long term incentive plan grants	1,871,655						
Long term incentive plan forfeitures	(22,500)						
Net income						2,417	2,417
Repurchase of stock				414,055	(787)		(787)
Share-based compensation			3,063				3,063
BALANCE, December 31, 2010	82,597,829	$ 8	$ 226,042	4,210,846	$ (6,976)	$ (214,907)	$ 4,167

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,		
	2010	**2009**	**2008**
OPERATING ACTIVITIES:			
Net income (loss)	$ 2,417	$ (58,383)	$ (129,953)
Adjustments to reconcile net income (loss) to net cash provided by operating activities-			
Depreciation and amortization	27,225	31,650	46,512
Amortization of deferred loan costs	2,088	1,642	1,197
Non-cash interest	3,086	1,605	
Accretion expense	1,527	1,976	2,207
Impairment		47,613	269,886
Unrealized (gain) loss on derivatives, net of premium amortization	(1,498)	32,147	(31,762)
Deferred income tax provision (benefit)	577	(16,865)	(92,595)
Other expense (income)	(574)	448	13,184
Share-based compensation	3,110	2,179	2,563
Loss (gain) on disposal of other property, equipment and subsidiary	(38)	35	180
Undistributed losses on investment			165
Changes in operating assets and liabilities, net of acquisitions-			
Accounts receivable	3,704	(650)	4,168
Prepaid expenses, inventory and other assets	1,857	905	(4,283)
Derivative premiums	(4,468)	(1,781)	(2,288)
Accounts payable and proceeds due others	543	(10,641)	14,606
Accrued liabilities and other	(1,527)	(15,387)	(3,124)
Restricted cash		16,000	(16,000)
Income taxes payable	44	256	231
Asset retirement obligations	(198)	(377)	(440)
Total adjustments	35,458	90,755	204,407
Net cash provided by operating activities	37,875	32,372	74,454
INVESTING ACTIVITIES:			
Payments for oil and natural gas properties and equipment	(33,535)	(29,871)	(84,723)
Proceeds from sales of oil and natural gas properties	49,366	6,120	2,950
Payments for other property and equipment	(865)	(604)	(1,275)
Proceeds from sales of other property and equipment	4	434	23
Proceeds from sale of subsidiary, net of cash			308
Acquisition of Ascent, net of cash acquired			35
Other investments			114
Net cash provided by (used in) investing activities	14,970	(23,921)	(82,568)
FINANCING ACTIVITIES:			

Payments on long-term debt	(98,490)	(36,156)	(175,306)
Proceeds from borrowings on long-term debt	46,340	30,022	90,253
Payments for deferred loan costs		(2,324)	(74)
Stock repurchased	(787)	(28)	(82)
Warrants exercised			86,614
Net cash provided by (used in) financing activities	(52,937)	(8,486)	1,405
DECREASE IN CASH AND CASH EQUIVALENTS	(92)	(35)	(6,709)
CASH AND CASH EQUIVALENTS, beginning of year	129	164	6,873
CASH AND CASH EQUIVALENTS, end of year	$ 37	$ 129	$ 164

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

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RAM Energy Resources, Inc.

Consolidated Statements of Cash Flows (continued)
(In thousands)

	Years Ended December 31,		
	2010	**2009**	**2008**
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for income taxes	$ 380	$ 303	$ 682
Cash paid for interest	$ 17,988	$ 13,428	$ 25,813
DISCLOSURE OF NON CASH INVESTING AND FINANCING ACTIVITIES:			
Asset retirement obligations	$ 3,006	$ (4,724)	$ 787
Receipt of common stock for settlement of contingent receivable	$	$ 2,134	$

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

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RAM Energy Resources, Inc.

Notes to consolidated financial statements
December 31, 2010 and 2009

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

1. Nature of Operations and Organization

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

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

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

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

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

2. Basis of Presentation

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

3. Properties and Equipment

The Company follows the full cost method of accounting for oil and natural gas operations. Under this method all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of oil and natural gas reserves are capitalized. No gains or losses are recognized upon the sale or other disposition of oil and natural gas properties except in transactions that would significantly alter the relationship between capitalized costs and proved reserves. The costs of unevaluated oil and natural gas properties are excluded from the amortizable base until the time that either proven reserves are found or it has been determined that such properties are impaired. As properties become evaluated, the related costs transfer to proved oil and natural gas properties using full cost accounting. All capitalized costs were included in the amortization base as of December 31, 2010 and 2009.

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.

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RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

In calculating future net revenues, prices and costs are held constant indefinitely, except for changes that are fixed and determinable by existing contracts. The net book value is compared to the Ceiling Limitation on a quarterly and yearly basis. The excess, if any, of the net book value above the Ceiling Limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. At December 31, 2010, the net book value of the Company s oil and natural gas properties did not exceed the Ceiling Limitation. At March 31, 2009, the net book value of the Company s oil and natural gas properties exceeded the Ceiling Limitation resulting in a reduction in the carrying value of the Company s oil and natural gas properties of $47.6 million. The after-tax effect of this reduction was $30.3 million. At December 31, 2009, the net book value of the Company s oil and natural gas properties did not exceed the Ceiling Limitation. At December 31, 2008, the net book value of the Company s oil and natural gas properties exceeded the Ceiling Limitation resulting in a reduction in the carrying value of the Company s oil and natural gas properties by $269.4 million. The after-tax effect of this reduction in 2008 was $171.6 million.

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

The Company has capitalized internal costs of approximately $3.1 million, $3.2 million and $5.0 million for the years ended December 31, 2010, 2009, and 2008, respectively. Such capitalized costs include salaries and related benefits of individuals directly involved in the Company s acquisition, exploration and development activities based on the percentage of their time devoted to such activities.

Other property and equipment consists principally of furniture and equipment and leasehold improvements. Other property and equipment and related accumulated depreciation and amortization are relieved upon retirement or sale and the gain or loss is included in operations. Renewals and replacements that extend the useful life of property and equipment are treated as capital additions. Accumulated depreciation of other property and equipment at December 31, 2010 and 2009 is approximately $6.7 million and $5.8 million, respectively.

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

4. Depreciation and Amortization

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

5. Natural Gas Sales and Gas Imbalances

The Company follows the entitlement method of accounting for natural gas sales, recognizing as revenues only its net interest share of all production sold. Any amount attributable to the sale of production in excess of or less than the Company s net interest is recorded as a gas balancing asset or liability. At December 31, 2010 and 2009, the Company s gas imbalances were immaterial.

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

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 2010, 2009, and 2008 approximately 61%, 61% and 53%, respectively, of total revenues were to one customer. The Company provides an allowance for doubtful accounts for certain purchasers and certain joint interest owners receivable balances when the Company believes the receivable balance may not be collected. Accounts receivable are presented net of the related allowance for doubtful accounts.

In 2010 and 2009 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.

In March 2011, the Company entered into new credit facilities, which replaced the $500.0 million facility in place at December 31, 2010. See Note C-2. In accordance with Topic 470 of the Codification, the Company will be required to expense $1.3 million of existing deferred loan costs during the first quarter of 2011 upon retirement of the existing debt. The remaining deferred loan costs and the deferred loan costs incurred to issue the new facilities will be amortized over the term of the related new loan.

9. General and Administrative Expense

The Company receives fees for the operation of jointly owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $0.6 million, $0.6 million and $0.5 million for the years ended December 31, 2010, 2009, and 2008, respectively.

10. Use of Estimates

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

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

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

12. Fair Value of Financial Instruments

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

Credit facilities: 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 2009 and 2008 have been made to conform to the 2010 presentation. These reclassifications had no effect on net income or loss or cash flows from operating, investing or financing activities.

14. Derivatives

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

The Company entered into numerous derivative contracts to reduce the impact of oil and natural gas price fluctuations and as required by the terms of its credit facilities (see Notes C and J). The Company did not designate these transactions as hedges. Accordingly, all gains and losses on the derivative instruments during 2010, 2009 and 2008 have been recorded in the statements of operations.

15. Income (Loss) per Common Share

Basic and diluted income (loss) per share is computed by dividing net earnings (loss) by the weighted average number of common shares outstanding for the period. A reconciliation of net income (loss) and

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

weighted average shares used in computing basic and diluted net income (loss) per share are as follows for the years ended December 31 (in thousands, except per share amounts):

	2010	2009	2008
Net income (loss)	$ 2,417	$ (58,383)	$ (129,953)
Weighted average shares basic	78,426,179	77,601,057	72,234,750
Dilutive effect of warrants			
Weighted average shares dilutive	78,426,179	77,601,057	72,234,750
Basic income (loss) per share	$ 0.03	$ (0.75)	$ (1.80)
Diluted income (loss) per share	$ 0.03	$ (0.75)	$ (1.80)

16. Asset Retirement Obligations

Authoritative guidance, set forth in Topic 410 of the Codification, addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The authoritative guidance requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company determines its asset retirement obligation on its 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 the Company s 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, 2010 and 2009 (in thousands):

	2010	2009
Liability for asset retirement obligations, beginning of year	$ 27,074	$ 30,199
Accretion expense	1,527	1,976
Change in estimates	3,475	(4,498)
Obligations for wells acquired and wells drilled	191	864
Obligations for wells sold or retired	(858)	(1,467)
Liability for asset retirement obligations, end of year	31,409	27,074
Less: current asset retirement obligation	639	711
Long-term asset retirement obligations	$ 30,770	$ 26,363

17. Income Taxes

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

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18. Uncertain Tax Positions

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

A rollforward of activity from January 1, 2008 follows (in thousands):

Uncertain Tax Positions:		
Balance as of December 31, 2007	$	6,855
Additions for tax positions of prior periods		127
Decreases in tax positions in prior period		
Settlements		
Additions based on tax positions related to the current year		
Lapse of statute of limitations		(6,982)
Balance as of December 31, 2008	$	
Additions for tax positions of prior periods		
Decreases in tax positions in prior period		
Settlements		
Additions based on tax positions related to the current year		
Lapse of statute of limitations		
Balance as of December 31, 2009	$	
Additions for tax positions of prior periods		
Decreases in tax positions in prior period		
Settlements		
Additions based on tax positions related to the current year		
Lapse of statute of limitations		
Balance as of December 31, 2010	$	

The Company has no liability for unrecognized tax benefits recorded as of December 31, 2010 and 2009, and there was no change to the Company s unrecognized tax benefits during the year ended December 31, 2010. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the statement of operations or statement of financial position as of December 31, 2010. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease within the next twelve months. The amount of interest related to unrecognized tax benefits which was decreased due to expirations of applicable statutes of limitations was $0.1 million during the year ended December 31, 2008. The Company recognizes related interest and penalties as a component of income tax expense.

Tax years open for audit by federal tax authorities and for state tax authorities as of December 31, 2010 are the years ended December 31, 2007, 2008, 2009 and 2010. Tax years ending prior to 2007 are open for

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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

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

In January 2009, the FASB issued guidance on fair value disclosures to enhance disclosures surrounding the transfers of assets in and out of Level 1 and Level 2, to present more detail surrounding asset activity for Level 3 assets and to clarify existing disclosure requirements. The new guidance is set forth in Topic 820 of the Codification and is effective for the Company beginning January 1, 2010. Additional disclosure about purchases, sales, issuances, and settlement in the roll forward of activity in Level 3 fair value measurements is effective beginning January 1, 2011. Adoption of the guidance on January 1, 2010 did not, and adoption of the guidance on January 1, 2011 will not, have any impact the Company s financial position or statement of operations.

In February 2010, the FASB issued an update to authoritative guidance, as set forth in Topic 855 of the Codification, relating to subsequent events, which was effective upon the issuance of the update. The Company adopted this authoritative guidance during the first quarter of 2010. The update removes the requirement for U.S. Securities and Exchange Commission filers to disclose the date through which subsequent events have been evaluated in both issued and revised financial statements. The adoption of this update did not impact the Company s financial position or statement of operations other than removing the disclosure.

In December 2010, the FASB issued an update to authoritative guidance, as set forth in Topic 805 of the Codification, relating to business combinations. This update provides clarification requiring public companies that have completed material acquisitions to disclose the revenue and earnings of the combined business as if the acquisition took place at the beginning of the comparable prior annual reporting period, and also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, non-recurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The Company will be required to apply this guidance prospectively for business combinations for which the acquisition date is on or after January 1, 2011. The Company does not expect the adoption of this new guidance to have a material impact on its financial position or statement of operations.

20. Subsequent Events

In March 2011, the Company entered into new credit facilities. The facilities, which replaced the Company s previous $500.0 million facility, include a $250.0 million first lien revolving credit facility with an initial $150.0 million borrowing base and a $75.0 million second lien term loan facility. See Note C for

RAM Energy Resources, Inc.

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additional discussion on the new credit facilities. See Note A-8 for additional discussion on treatment of deferred loan costs related to the refinancing.

The Company evaluates events and transactions after the balance sheet date but before the financial statements are filed with the U.S. Securities and Exchange Commission. No events other than those described in these notes, have occurred that have required disclosure.

B SIGNIFICANT DIVESTITURES

1. North Texas Barnett Shale & Boonsville Divestitures

On December 8, 2010, the Company closed the sale on all of its oil and natural gas properties and related assets located in the Boonsville and Newark East fields of Jack and Wise Counties in Texas to Milagro Producing, LLC for $43.7 million (prior to closing adjustments). The effective date under the agreement was October 1, 2010. In accordance with the full cost method of accounting, the Company did not record a gain or loss on the sale. The full cost pool at December 31, 2010 was reduced by the net proceeds, including closing adjustments, of $41.0 million. Proceeds of $16.0 million were used to reduce the outstanding balance on the Company s revolving credit facility and the remaining net proceeds were used to reduce the outstanding balance on the Company s term loan. See Note C.

2. Eastern Oklahoma Divestiture

On December 30, 2010, the Company closed the sale on certain non-operated natural gas properties located in eastern Oklahoma for $8.0 million (prior to closing adjustments). The effective date under the agreement was December 1, 2010. The full cost pool at December 31, 2010 was reduced by the net proceeds, including closing adjustments, of $7.8 million in accordance with the full cost method of accounting. The proceeds were used to reduce outstanding borrowings under the Company s revolving credit facility. See Note C.

C LONG-TERM DEBT

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

	2010	2009
Credit facility	$ 196,521	$ 245,730
Accrued payment-in-kind interest	221	262
Installment loan agreements	350	175
	197,092	246,167
Less amount due within one year	127	126
	$ 196,965	$ 246,041

The amounts of required principal payments as of December 31, 2010, are as follows (in thousands):

2011	$ 127
2012	104
2013	63
2014	34
2015	22
2016	196,742
	$ 197,092

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

1. Senior Notes

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

2. Credit Facilities

Credit Facilities. In November 2007, in conjunction with the Ascent acquisition, the Company entered into a $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. The facility included a $250.0 million revolving credit facility and a $200.0 million term loan facility and an additional $50.0 million available under the term loan as requested by the Company and approved by the lenders. The initial amount of the $200.0 million term loan was advanced at closing. The borrowing base under the revolving credit facility initially was set at $175.0 million, a portion of which was advanced at the closing of the Ascent acquisition. Borrowings under the 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 initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The term loan provided for payments of interest only during its term, with the initial interest rate being LIBOR plus 7.5%. Effective September 30, 2010, the borrowing base was redetermined at $165.0 million based on the value of the Company s proved reserves at June 30, 2010. As a result of the reduction in collateral, represented by the North Texas Barnett Shale and Boonsville asset sale, the Company s borrowing base of $165.0 million was reset at $145.0 million as of December 31, 2010. The Eastern Oklahoma asset sale had no impact on the Company s borrowing base. See Note B.

Advances under the facility were secured by liens on substantially all properties and assets of the Company and its subsidiaries. The loan agreement contained representations, warranties and covenants customary in transactions of this nature. During May 2008, the Company reduced its outstanding balance on the term facility by $86.6 million of net proceeds, which it realized upon the exercise of 17,617,331 warrants. See Note F.

On June 26, 2009, the Company entered into the Second Amendment to the credit facility. The Second Amendment amended certain definitions and certain financial and negative covenant terms providing greater flexibility for the Company through the remaining term of the facility. Additionally, the Second Amendment increased the interest rates applicable to borrowings under both the revolver and term loans. Advances under the revolver bore interest at LIBOR, with a minimum LIBOR rate, or floor, of 1.5%, plus a margin ranging from 2.25% to 3.0% based on a percentage of usage. The term loan bore interest at LIBOR, also with a floor of 1.5%, plus a margin of 8.5%, and an additional 2.75% of payment-in-kind interest that was added to the term loan principal balance on a monthly basis and paid at maturity. The Company was in compliance with all of its covenants in the credit facility at December 31, 2010. At December 31, 2010, $116.5 million was outstanding under the revolving credit facility and $80.2 million was outstanding under the term facility, including $0.2 million accrued payment-in-kind interest.

In March 2011, the Company entered into new credit facilities. The new facilities, which replaced the Company s previous facility, include a $250.0 million first lien revolving credit facility and a $75.0 million second lien term loan facility. SunTrust Bank is the administrative agent for the revolving facility, and Guggenheim Corporate Funding, LLC is the agent for the term loan facility. The initial borrowing base under the revolving credit facility at the closing is $150.0 million. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the five-year term of the revolver, and initially bear interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The term loan portion of the Company s credit facility provides for payments of interest only during its 5.5-year term, with the initial interest rate being LIBOR plus 9.0% with a 2.0% LIBOR floor, or if any period we elect to pay a portion of

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

the interest under our term loan in kind, then the interest rate will be LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to principal. Due to refinancing of the Company s outstanding debt prior to the issuance of the financial statements, the current portion of existing debt at December 31, 2010 is considered long-term.

The new credit facilities contain representations, warranties and covenants customary in transactions of this nature, including restrictions on the payment of dividends on our capital stock and financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to total indebtedness. The Company is required to maintain commodity hedges on a rolling basis for the first 12 months out with respect to not less than 60%, but not more than 85%, and for the next 18 months out with respect to not less than 50% but not more than 85%, of projected quarterly production volumes, until the leverage ratio is less than or equal to 1.5 to 1.0.

D LEASES

The Company leases office space and certain equipment under non-cancelable operating lease agreements that expire on various dates through 2014. Approximate future minimum lease payments for operating leases at December 31, 2010 are as follows (in thousands):

Year Ending December 31,	
2011	$ 1,189
2012	1,165
2013	1,048
2014	58
2015	2
	$ 3,462

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

E DEFINED CONTRIBUTION PLAN

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all of its employees. The plan allows eligible employees to contribute up to 100% of their annual compensation, not to exceed the maximum amount permitted by IRS regulations. Employer contributions to the plan are discretionary. The Company provided matching contributions to the plan in 2010, 2009, and 2008 of $0.7 million, $0.7 million and $0.6 million, respectively.

F CAPITAL STOCK

On May 8, 2006, the shareholders of the Company approved the Company s 2006 Long-Term Incentive Plan (the Plan), effective upon the consummation of the Company s acquisition by merger of RAM Energy. Under the terms of the Plan, at such time as restricted stock awards vest, the grantee has the right to request the Company to repurchase, at the closing market price of the Company s common stock as of the vesting date, the number of vested shares necessary to satisfy minimum income tax withholding requirements. Pursuant to this provision, since inception of the Plan in 2006, the Company has repurchased, upon vesting, a total of 587,861 shares of common stock at an average price of $2.84 per share. The shares purchased by the Company are held as treasury shares.

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Notes to consolidated financial statements (Continued)

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

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

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

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

G INCOME TAXES

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

	Years Ended December 31,		
	2010	**2009**	**2008**
Current	$ (418)	$ (518)	$ (912)
Deferred	(577)	16,865	92,595
(Provision) benefit for income tax	$ (995)	$ 16,347	$ 91,683

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, change in valuation allowance, Section 382 net operating loss limitations and previously unrecognized tax benefits.

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Notes to consolidated financial statements (Continued)

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

	Years Ended December 31, 2010	2009	2008
Income tax benefit (expense) at the federal statutory rate (34%)	$ (1,160)	$ 25,408	$ 75,356
State income tax benefit, net of federal benefit	(124)	(508)	6,033
Meals and entertainment expense	(25)	(27)	(102)
Non-deductible dues	(69)	12	(33)
Previously unrecognized tax benefits			11,613
Interest on previously unrecognized tax benefits			(127)
Reduction in deferred tax asset for Section 382 net operating loss limitations	(5,731)		
Change in valuation allowance	6,572	(7,433)	(2,234)
Share-based compensation	(393)	(559)	(119)
Other	(65)	(546)	1,296
Income tax benefit (provision)	$ (995)	$ 16,347	$ 91,683

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

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RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

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

	December 31, 2010	December 31, 2009
Deferred tax assets:		
Current:		
Derivative liabilities	$ 2,298	$ 2,226
Accrued expenses and other	1,873	2,675
Total current deferred tax assets	$ 4,171	$ 4,901
Valuation allowance	(445)	(1,138)
Net current deferred tax assets	$ 3,726	$ 3,763
Noncurrent:		
Depreciable/depletable property, plant and equipment	$ 13,268	$ 3,024
Net operating loss carryforward	20,254	36,644
Accrued liabilities and other	1,381	1,688
Total noncurrent deferred tax assets	$ 34,903	$ 41,356
Valuation allowance	(3,723)	(9,603)
Net noncurrent deferred tax assets	$ 31,180	$ 31,753
Deferred tax liabilities:		
Current:		
Prepaid expenses and other	$ (200)	$ (232)
Total current deferred tax liability	(200)	(232)
Noncurrent:		
Depreciable/depletable property, plant and equipment	$	$
Other	(179)	(180)
Total noncurrent deferred tax liabilities	$ (179)	$ (180)
Net deferred tax liability	$ (379)	$ (412)
Net deferred tax asset	$ 34,527	$ 35,104

As of December 31, 2010, the Company has net operating loss carryforwards of approximately $129.1 million for federal income tax reporting purposes, the majority of which were an inherited attribute from the Ascent acquisition during 2007. If not used, the net operating losses will generally expire between 2020 and 2029. The majority of 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 $82.6 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.

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

A valuation allowance has been established with respect to the portion of the deferred tax asset associated with its net operating losses for which the Company currently does not reasonably believe under the deferred tax asset realization criteria set forth in Topic 740 that it will more likely than not realize a benefit in future periods. During the year ended December 31, 2010, the Company recorded a decrease in the valuation allowance of $6.6 million.

H COMMITMENTS AND CONTINGENCIES

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

I FAIR VALUE MEASUREMENTS

The Company measures the fair value of its derivative instruments according to the fair value hierarchy, as set forth in Topic 820 of the Codification. Topic 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The fair value measurement of the Company s net derivative assets as of December 31, 2010 was $1.1 million and of its net derivative liabilities as of December 31, 2009 was $4.8 million, based on Level 2 criteria. See Note J.

At December 31, 2010, the carrying value of cash, receivables and payables reflected in the Company s consolidated financial statements approximates fair value due to their short-term nature. Additionally, the carrying value of the Company s long-term debt under the credit facility approximates fair value because the credit facility carries a variable interest rate based on market interest rates. See Note C for discussion of long-term debt.

J DERIVATIVE CONTRACTS

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

During 2010, 2009 and 2008, the Company entered into numerous derivative contracts to manage the impact of oil and natural gas price fluctuations and as required by the terms of its credit facility.

The Company did not designate these transactions as hedges. Accordingly, all gains and losses on the derivative instruments during 2010, 2009 and 2008 have been recorded in the statements of operations.

The Company s derivative positions at December 31, 2010, consisting of put/call collars and put options, also called bare floors as they provide a floor price without a corresponding ceiling, are shown in the following table:

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Notes to consolidated financial statements (Continued)

	Crude Oil (Bbls)					Natural Gas (Mmbtu)				
	Floors		Ceilings			Floors		Ceilings		
ollars	**Per Day(1)**	**Price**	**Per Day(1)**	**Price**	**Months Covered**	**Per Day(1)**	**Price**	**Per Day(1)**	**Price**	**Months Covere**
011	1,921	$ 80.00	1,921	$ 105.00	April December	6,219	$ 5.00	6,219	$ 9.48	January Septemb
012	995	$ 80.00	995	$ 105.00	January June					

	Bare Floors			Bare Floors		
Year	**Per Day(1)**	**Price**	**Months Covered**	**Per Day(1)**	**Price**	**Months Covered**
2011	1,177	$ 60.00	January September	1,841	$ 4.18	October December
2012				2,486	$ 4.25	January March

(1) Per day amounts are calculated based on a 365-day year for 2011 and on a 366-day year for 2012.

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. The Company estimated the fair value of its derivatives using a pricing model which also considered market volatility, counterparty credit risk and additional criteria in determining discount rates. See Note I. The discount rate used in the discounted cash flow projections was based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The counterparty credit risk was determined by calculating the difference between the derivative counterparty s bond rate and published bond rates. The Company incorporates its credit risk when the derivative position is a liability by using its LIBOR spread rate.

Gross fair values of the Company s derivative instruments, prior to netting of assets and liabilities subject to a master netting arrangement, as of December 31, 2010 and 2009 and the consolidated statements of operations for the years ended December 31, 2010, 2009 and 2008 are as follows (in thousands):

CONSOLIDATED BALANCE SHEETS

		Fair Value as of December 31,	
Gross Assets and Liabilities	**Balance Sheet Location**	**2010**	**2009**
Current Assets Derivative assets	Current Assets Derivative assets	$ 1,904	$
Current Assets Derivative assets	Current Liabilities Derivative liabilities		413
Other Assets Derivative assets	Long-Term Liabilities Derivative liabilities	207	200
Current Liabilities Derivative liabilities	Current Assets Derivative assets	(564)	
Current Liabilities Derivative liabilities	Current Liabilities Derivative liabilities		(4,884)
Long-Term Liabilities Derivative liabilities	Long-Term Liabilities Derivative liabilities	(410)	(558)

Total Derivatives Not Designated as Hedging Instruments	$ 1,137	$ (4,829)

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RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

CONSOLIDATED STATEMENTS OF OPERATIONS

Location		Years Ended December 31, 2010	2009	2008
Revenue	Unrealized gains (losses) on derivatives	$ 6,386	$ (30,561)	$ 33,257
Revenue	Realized gains (losses) on derivatives	$ (5,193)	$ 19,255	$ (10,472)

K LIQUIDITY

As of December 31, 2010, the Company had an accumulated deficit of $214.9 million and a working capital deficit of $12.4 million. Management believes that borrowings currently available to the Company under the Company s credit facilities and anticipated cash flows from operations will be sufficient to satisfy its currently expected capital expenditures, working capital, and debt service obligations through 2011. The actual amount and timing of future capital requirements may differ materially from estimates as a result of, among other things, changes in product pricing and regulatory, technological and competitive developments. Sources of additional financing may include commercial bank borrowings, vendor financing and the sale of oil and natural gas properties or equity or debt securities. Management cannot assure that any such financing will be available on acceptable terms or at all.

L SHARE-BASED COMPENSATION

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

On May 8, 2006, the Company s stockholders approved its 2006 Long-Term Incentive Plan (the Plan). The Company reserved a maximum of 2,400,000 shares of its common stock for issuances under the Plan. The Plan includes a provision that, at the request of a grantee, the Company may repurchase shares to satisfy the grantee s federal and state income tax and other payroll 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. On May 3, 2010, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 6,000,000 to 7,400,000. As of December 31, 2010, a maximum of 1,960,271 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, 2010 were as follows:

	Shares Repurchased	
Year Ended	Number	Weighted Average Closing Price

December 31, 2008	20,549	$ 3.98
December 31, 2009	21,541	$ 1.33
December 31, 2010	414,055	$ 1.90

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

A summary of the status of the non-vested shares as of December 31, 2010, and changes during the three year period ended December 31, 2010, is presented below:

Nonvested Shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2008	802,686	$ 4.28
Granted	1,104,800	$ 4.84
Vested	(297,849)	$ 4.95
Forfeited	(141,393)	$ 5.03
Nonvested at December 31, 2008	1,468,244	$ 4.79
Granted	1,343,000	$ 0.95
Vested	(429,351)	$ 4.81
Forfeited	(17,900)	$ 1.20
Nonvested at December 31, 2009	2,363,993	$ 2.64
Granted	1,871,655	$ 1.99
Vested	(1,557,476)	$ 2.65
Forfeited	(22,500)	$ 2.27
Nonvested at December 31, 2010	2,655,672	$ 2.17

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 and other payroll withholding requirements. The repurchased shares were held by the Company as treasury stock at December 31, 2010.

As of December 31, 2010, the Company had $5.1 million of unrecognized share-based compensation related to awards granted under the Plan. That cost is expected to be recognized over a weighted-average period of two years. The related compensation expense recognized during the years ended December 31, 2010, 2009 and 2008 was $3.1 million, $2.2 million and $2.6 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 and Oklahoma. The Company does not own or lease any oil and natural gas properties outside the United States of America.

The Company retains independent engineering firms to provide year-end estimates of the Company s future net recoverable oil, natural gas and natural gas liquids reserves. Estimated proved net recoverable reserves as shown below include only those quantities that can be expected to be commercially recoverable. Estimated reserves for the year ended December 31, 2010 and 2009 were computed using benchmark prices based on the unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas during each month of 2010 and 2009, as required by SEC Release No. 33-8995 *Modernization of Oil and Gas*

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RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

Reporting, effective December 31, 2009, while estimated reserves for the years ended December 31, 2008 were based on oil and natural gas spot prices as of the end of the period presented. Costs were estimated using costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods.

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

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

	2010	2009	2008
Proved oil and natural gas properties	$ 689,472	$ 702,502	$ 683,341
Unevaluated oil and natural gas properties			
Accumulated depreciation, amortization and impairment	(482,886)	(456,720)	(378,445)
	$ 206,586	$ 245,782	$ 304,896

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):

	2010	2009	2008
Acquisition of proved properties	$ 1,133	$ 1,311	$ 10,091
Acquisition of unproved properties			2,691
Development costs	27,850	28,239	57,084
Exploration costs	4,552	321	14,857
Additional asset retirement obligation	191	864	2,051
	$ 33,726	$ 30,735	$ 86,774
Amortization rate per equivalent oil barrel	$ 12.11	$ 12.06	$ 17.89

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

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, 2007	19,544	93,358	4,271
Extensions and discoveries	631	18,647	1,071
Sales of reserves in place	(85)	(701)	
Purchases of reserves in place	151	135	
Revisions of previous estimates	(4,769)	(8,405)	(663)
Production	(1,187)	(6,082)	(354)
December 31, 2008	14,285	96,952	4,325
Extensions and discoveries	1,771	10,070	508
Sales of reserves in place	(15)	(3,808)	
Purchases of reserves in place			
Revisions of previous estimates	(836)	(7,993)	556
Production	(1,138)	(5,994)	(406)
December 31, 2009	14,067	89,227	4,983
Extensions and discoveries	347	821	61
Sales of reserves in place	(174)	(14,591)	(2,004)
Purchases of reserves in place			
Revisions of previous estimates	(159)	(17,033)	(301)
Production	(995)	(4,816)	(364)
December 31, 2010	13,086	53,608	2,375
Proved developed reserves:			
December 31, 2008	9,235	57,635	2,705
December 31, 2009	8,814	46,159	2,788
December 31, 2010	8,414	31,776	1,486

The Company added 0.5 million barrels of oil equivalent in proved reserve extensions and discoveries in 2010 as a result of development drilling in its Electra/Burkburnett field in North Texas and in its La Copita field in South Texas. A significant portion of these reserves is a result of drilling locations in its Electra/Burkburnett field that were not booked as proved locations at year-end 2009. The remainder of the extensions and discoveries in 2010 is primarily from wells drilled in South Texas not previously booked as proved and from a discovery well in Osage County, Oklahoma. Sales of reserves in place during 2010 were primarily due to sales of assets during December 2010 of the Company s North Texas Barnett Shale and Boonsville properties and certain non-operated natural gas properties located in eastern Oklahoma. The revisions of previous reserve estimates decreased proved reserves by 3.3 million barrels of oil equivalent or approximately 10% of proved reserves at the beginning of the year. The revisions included a positive increase of 1.8 million barrels of oil equivalent caused by higher oil and gas prices. This positive revision was offset by a downward revision of 1.1 million barrels of oil equivalent caused by the transfer of proved undeveloped to unproved categories as a result of changes to the Company s development plans during 2010, and 4.0 million barrels of oil equivalent of the downward revisions were mostly due to changes in well performance in the Company s gas properties in South Texas. The Company added 3.9 million barrels of oil equivalent in proved

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

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

Impact of Implementation of New Oil and Gas Rules Effective December 31, 2009

Implementation of the SEC s updated rules using first-day-of-the-month average prices for 2009 resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules using year-end 2009 pricing. Use of 12-month average pricing at December 31, 2009 as required by the updated rules resulted in a decrease in proved reserves of approximately 3,692 thousand barrels of oil equivalent, when compared to reserves prepared under the previous rules. In addition, at December 31, 2009, the new proved undeveloped reserves rules resulted in a reduction of proved reserves of approximately 750 barrels of oil due to the SEC s new five-year scheduling rule. The majority of the reserves reclassified out of proved reserves were associated with smaller secondary reserve waterflood projects.

Standardized Measure

The following is a summary of a standardized measure of discounted net cash flows related to the Company s proved oil and natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves for the year ended December 31, 2010 and 2009 were computed using benchmark prices based on the unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas during each month of 2009, as required by SEC Release No. 33-8995, Modernization of Oil and Gas Reporting, effective December 31, 2009, while estimated cash flows for the years ended December 31, 2008 were based on oil and natural gas spot prices as of the end of the period presented. Future development and production costs attributable to the proved reserves were estimated assuming that existing conditions would continue over the economic lives of the individual leases and costs were not escalated for the future. Estimated future income tax expenses were calculated by applying future statutory tax rates (based on the current tax law adjusted for permanent differences and tax credits) to the estimated future pretax net cash flows related to proved oil and natural gas reserves, less the tax basis of the properties involved.

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

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):

	2010	2009	2008
Future cash inflows	$ 1,355,233	$ 1,314,714	$ 1,253,537
Future production costs	(548,638)	(535,784)	(472,191)
Future development costs	(117,860)	(148,956)	(145,086)

Future income tax expenses	(161,736)	(123,943)	(103,434)
Future net cash flows	526,999	506,031	532,826
10% annual discount for estimated timing of cash flows	(248,952)	(231,797)	(248,373)
Standardized measure of discounted future net cash flows	$ 278,047	$ 274,234	$ 284,453

RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

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):

	2010	2009	2008
Standardized measure of discounted future net cash flows at beginning of year	$ 274,234	$ 284,453	$ 598,395
Changes during the year:			
Sales and transfers of oil and natural gas produced, net of production costs	(71,028)	(55,393)	(134,180)
Net changes in prices and production costs	119,370	1,272	(538,042)
Extensions and discoveries, less related costs	13,888	31,264	77,239
Development costs incurred and revisions	15,656	28,602	(2,973)
Sales of reserves in place	(25,267)	(5,598)	(5,143)
Purchases of reserves in place			3,494
Revisions of previous quantity estimates	(58,029)	(18,323)	(81,073)
Net change in income taxes	(24,382)	(24,245)	275,581
Accretion of discount	33,605	32,202	91,155
Net change	3,813	(10,219)	(313,942)
Standardized measure of discounted future net cash flows at end of year	$ 278,047	$ 274,234	$ 284,453

Prices used in computing these calculations of future cash flows from estimated future production of proved reserves were $76.80, $58.63, and $44.15 per barrel of oil at December 31, 2010, 2009, and 2008, respectively, $4.51, $3.76, and $5.33 per thousand cubic feet of natural gas at December 31, 2010, 2009, and 2008, respectively and $45.62, $31.03, and $23.59 per barrel of natural gas liquids at December 31, 2010, 2009, and 2008, respectively.

N QUARTERLY DATA (UNAUDITED)

	2010 Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands except per share data)			
Net revenue	$ 25,362	$ 27,083	$ 28,968	$ 30,921
Net operating expenses	22,244	21,068	22,237	21,066
Operating income	3,118	6,015	6,731	9,855
Interest expense	(5,539)	(5,767)	(5,714)	(5,635)
Interest income	3	20	2	2
Other income (expense)	28	(268)	570	(9)

Income (loss) before income taxes	(2,390)		1,589	4,213
Income tax provision (benefit)	1,904	(1,564)	(1,140)	1,795
Net income (loss)	$ (4,294)	$ 1,564	$ 2,729	$ 2,418
Basic net income (loss) applicable to common stockholders per common share	$ (0.05)	$ 0.02	$ 0.03	$ 0.03
Diluted net income (loss) applicable to common stockholders per common share	$ (0.05)	$ 0.02	$ 0.03	$ 0.03

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RAM Energy Resources, Inc.

Notes to consolidated financial statements (Continued)

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

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

No items to report.

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

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

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

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act) was performed as of the end of the period covered by this report. This evaluation was performed by our management, with the participation of our Chief Executive Officer and Chief Financial Officer. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures were effective at December 31, 2010.

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

Our management, including our Chief Executive Officer and Chief Financial Officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Our management concluded that the design and operations of our internal control over financial reporting at December 31, 2010, were

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effective and provide reasonable assurance the books and records accurately reflect the transactions of the Company.

There was no change in our internal control over financial reporting during the year ended December 31, 2010, that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

/s/ Larry E. Lee	/s/ G. Les Austin
Larry E. Lee Chairman, President and Chief Executive Officer	G. Les Austin Senior Vice President and Chief Financial Officer
March 16, 2011	March 16, 2011

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, 2010, 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 audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exist, testing and evaluating the design and operating effectiveness of internal control and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, RAM Energy Resources, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, 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, 2010, and our report dated March 16, 2011, expressed an unqualified opinion on those consolidated financial statements.

/s/ UHY LLP

Houston, Texas
March 16, 2011

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

No items to report.

PART III

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

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

The information required by this item will be set forth in our Definitive Proxy Statement on Schedule 14A relating to our 2011 Annual Meeting, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended, (the Proxy Statement). The Proxy Statement relates to a meeting of stockholders involving the election of directors and the portions therefrom required to be set forth in this Form 10-K by this item are incorporated herein by reference pursuant to General Instruction G(3) to Form 10-K.

Item 11. ***Executive Compensation***

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

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

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

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

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

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

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

PART IV

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

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

RAM Energy Resources, Inc.

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

(a) (3) *Exhibits*

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

Exhibit	Description	Method of Filing
3.1	Amended and Restated Certificate of Incorporation of the Registrant.	(1) [3.1]
3.2	Amended and Restated Bylaws of the Registrant.	(8) [3.2]
10.1	Form of Registration Rights Agreement among the Registrant and the Initial Stockholders.	(2) [10.9]
10.1.1	Amendment to Registration Rights Agreement among this Registrant and the Founders dated May 8, 2006.	(1) [10.9.1]
10.2	Employment Agreement between Registrant and Larry E. Lee dated May 8, 2006.*	(1) [10.15]
10.2.1	First Amendment to Employment Agreement between Registrant and Larry E. Lee dated October 18, 2006.*	(5) [10.1]
10.2.2	Second Amendment to Employment Agreement of Larry E. Lee dated February 25, 2008.*	(10) [10.6.2]
10.6.3	Third Amendment to Employment Agreement of Larry E. Lee dated December 30, 2008.*	(13) [10.6.3]
10.2.4	Fourth Amendment to Employment Agreement of Larry E. Lee dated March 24, 2009.*	(14) [10.6.4]
10.2.5	Fifth Amendment to Employment Agreement of Larry E. Lee dated March 17, 2010.*	(17) [10.6.5]
10.2.6		(21) [10.2.6]

	Sixth Amendment to Employment Agreement of Larry E. Lee dated March 8, 2011.*	
10.3	Escrow Agreement by and among the Registrant, Larry E. Lee and Continental Stock Transfer & Trust Company dated May 8, 2006.	(1) [10.16]
10.4	Registration Rights Agreement among Registrant and the investors signatory thereto dated May 8, 2006.*	(1) [10.7]
10.5	Form of Registration Rights Agreement among the Registrant and the Investors party thereto.	(3) [10.17]
10.6	Agreement between RAM and Shell Trading-US dated February 1, 2006.	(1) [10.22]
10.7	Agreement between RAM and Targa dated January 30, 1998.	(1) [10.23]

Exhibit	Description	Method of Filing
10.7.1	Amendment to Agreement between RAM Energy and Targa dated effective as of April 1, 2006, filed as an exhibit to Registrant s Form 8-K dated June 5, 2006, and incorporated by reference herein.	(6) [10.23.1]
10.8	Long-Term Incentive Plan of the Registrant. Included as Annex C of the Registrant s Definitive Proxy Statement (No. 000-50682), dated April 12, 2006, and incorporated by reference herein.*	(4) [Annex C]
10.8.1	First Amendment to the RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 8, 2008.*	(11) [Exhibit A]
10.8.2	Second Amendment to the RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 3, 2010.*	(18) [10.8.2]
10.9	Deferred Bonus Compensation Plan of RAM Energy, Inc. dated as of April 21, 2004.*	(7) [10.14]
10.10	Loan Agreement dated November 29, 2007, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(9) [10.1]
10.10.1	First Amendment to Loan Agreement dated February 6, 2009, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(15) [10.17.1]
10.10.2	Second Amendment to Loan Agreement dated June 26, 2009, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(16) [10.17.2]
10.10.3	Third Amendment to Loan Agreement dated November 29, 2010, effective December 3, 2010, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(20) [10.8.3]
10.11	Description of Compensation Arrangement with G. Les Austin.*	(12) [10.18]
10.11.1	First Amendment to Employment Agreement of G. Les Austin dated December 30, 2008.*	(13) [10.18.1]
10.12	Change in Control Separation Benefit Plan of Ram Energy Resources, Inc. and Participating Subsidiaries.	(15) [10.19]
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	the Lenders	
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21.1	Subsidiaries of the Registrant.	**
23.1	Consent of UHY LLP.	**

Exhibit	Description	Method of Filing
23.2	Consent of Forrest A. Garb & Associates, Inc.	**
31.1	Rule 13(A) 14(A) Certification of our Principal Executive Officer.	**
31.2	Rule 13(A) 14(A) Certification of our Principal Financial Officer.	**
32.1	Section 1350 Certification of our Principal Executive Officer.	**
32.2	Section 1350 Certification of our Principal Financial Officer.	**
99.1	Report of Forrest A. Garb & Associates, Inc.	**

* Management contract or compensatory plan or arrangement.

** Filed herewith.

(1) Filed as an exhibit to the Registrant s Current Report on Form 8-K filed on May 12, 2006, as the exhibit number indicated in brackets and incorporated by reference herein.

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

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

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

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

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

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

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

(9) Filed as an exhibit to Registrant s Form 8-K dated November 29, 2007, as the exhibit number indicated in brackets and incorporated by reference herein.

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

(17) Filed as an exhibit to Registrant s Form 8-K filed March 18, 2010, as the exhibit number indicated in brackets and incorporated by reference herein.

(18) Filed as an exhibit to Registrant s Form 8-K filed May 7, 2010, as the exhibit number indicated in brackets and incorporated by reference herein.

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(20) Filed as an exhibit to Registrant s Form 8-K filed December 8, 2010, as the exhibit number indicated in brackets and incorporated by reference herein.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Tulsa, State of Oklahoma, on March 16, 2011.

RAM ENERGY RESOURCES, INC.

By /s/ Larry E. Lee

Larry E. Lee,
Chairman of the Board, President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities indicated, on March 16, 2011.

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

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INDEX TO EXHIBITS

Exhibit	Description	Method of Filing
3.1	Amended and Restated Certificate of Incorporation of the Registrant.	(1) [3.1]
3.2	Amended and Restated Bylaws of the Registrant.	(8) [3.2]
10.1	Form of Registration Rights Agreement among the Registrant and the Initial Stockholders.	(2) [10.9]
10.1.1	Amendment to Registration Rights Agreement among this Registrant and the Founders dated May 8, 2006.	(1) [10.9.1]
10.2	Employment Agreement between Registrant and Larry E. Lee dated May 8, 2006.*	(1) [10.15]
10.2.1	First Amendment to Employment Agreement between Registrant and Larry E. Lee dated October 18, 2006.*	(5) [10.1]
10.2.2	Second Amendment to Employment Agreement of Larry E. Lee dated February 25, 2008.*	(10) [10.6.2]
10.6.3	Third Amendment to Employment Agreement of Larry E. Lee dated December 30, 2008.*	(13) [10.6.3]
10.2.4	Fourth Amendment to Employment Agreement of Larry E. Lee dated March 24, 2009.*	(14) [10.6.4]
10.2.5	Fifth Amendment to Employment Agreement of Larry E. Lee dated March 17, 2010.*	(17) [10.6.5]
10.2.6	Sixth Amendment to Employment Agreement of Larry E. Lee dated March 8, 2011.*	(21) [10.2.6]
10.3	Escrow Agreement by and among the Registrant, Larry E. Lee and Continental Stock Transfer & Trust Company dated May 8, 2006.	(1) [10.16]
10.4	Registration Rights Agreement among Registrant and the investors signatory thereto dated May 8, 2006.*	(1) [10.7]
10.5	Form of Registration Rights Agreement among the Registrant and the Investors party thereto.	(3) [10.17]
10.6	Agreement between RAM and Shell Trading-US dated February 1, 2006.	(1) [10.22]
10.7	Agreement between RAM and Targa dated January 30, 1998.	(1) [10.23]
10.7.1	Amendment to Agreement between RAM Energy and Targa dated effective as of April 1, 2006, filed as an exhibit to Registrant s Form 8-K dated June 5, 2006, and incorporated by reference herein.	(6) [10.23.1]
10.8	Long-Term Incentive Plan of the Registrant. Included as Annex C of the Registrant s Definitive Proxy Statement (No. 000-50682), dated April 12, 2006, and incorporated by reference herein.*	(4) [Annex C]
10.8.1	First Amendment to the RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 8, 2008.*	(11) [Exhibit A]
10.8.2	Second Amendment to the RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 3, 2010.*	(18) [10.8.2]
10.9	Deferred Bonus Compensation Plan of RAM Energy, Inc. dated as of April 21, 2004.*	(7) [10.14]
10.10	Loan Agreement dated November 29, 2007, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA	(9) [10.1]

Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.

Exhibit	Description	Method of Filing
10.10.1	First Amendment to Loan Agreement dated February 6, 2009, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(15) [10.17.1]
10.10.2	Second Amendment to Loan Agreement dated June 26, 2009, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(16) [10.17.2]
10.10.3	Third Amendment to Loan Agreement dated November 29, 2010, effective December 3, 2010, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(20) [10.8.3]
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