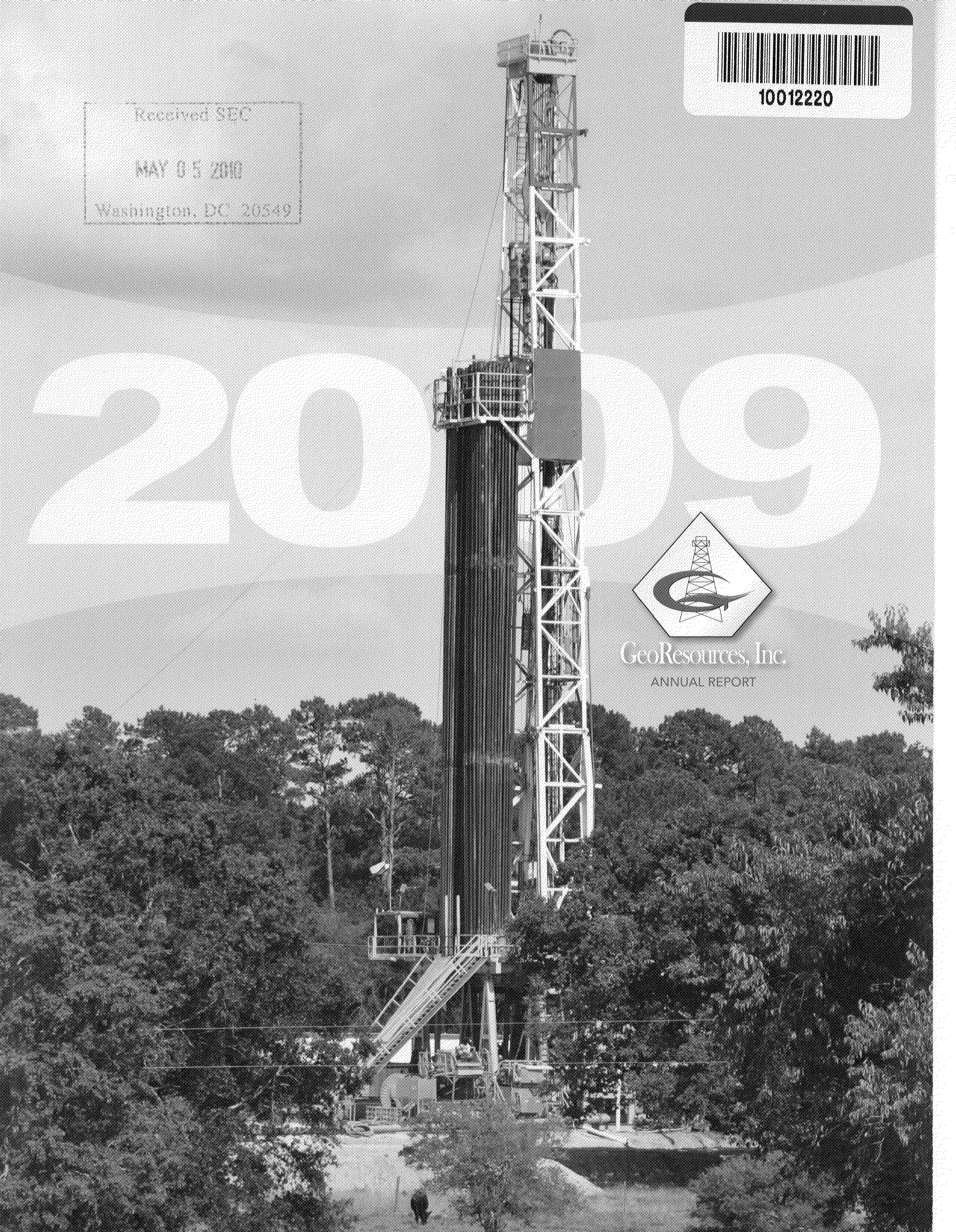


2009

GeoResources, Inc.
ANNUAL REPORT

About GeoResources, Inc.

GeoResources, Inc. owns and operates producing oil and gas properties in the Southwest, Gulf Coast and the Williston Basin, and conducts oil and gas exploration and development and production operations in these areas.

Our diversified business strategy is intended to preserve shareholder value while exposing the Company to significant growth opportunities.

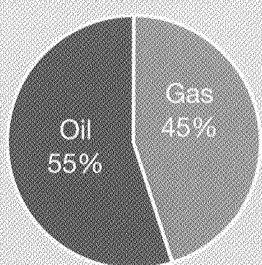
Our strategy includes the following:

- Acquiring additional oil and gas reserves through asset or corporate acquisitions or mergers;
- Expanding acreage and prospect inventory;
- Comprehensive field re-engineering; and
- Development, exploitation and exploration activities.

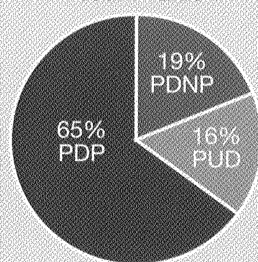
GeoResources, Inc. common stock trades on the NASDAQ Global Market under the ticker GEOI.

Proved Reserve Profile*

Reserve %

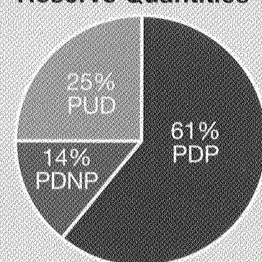


Present Value



$217.6 Million
PV-10 Value

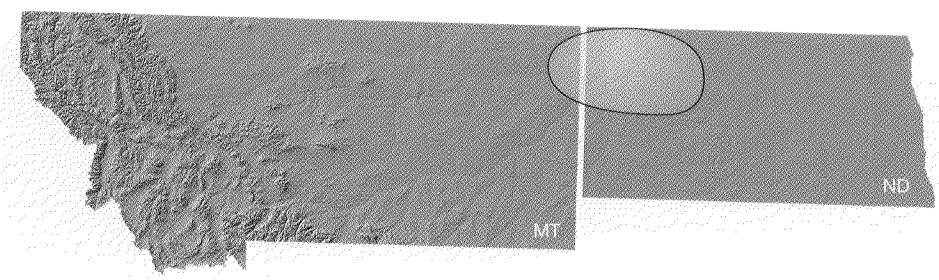
Reserve Quantities



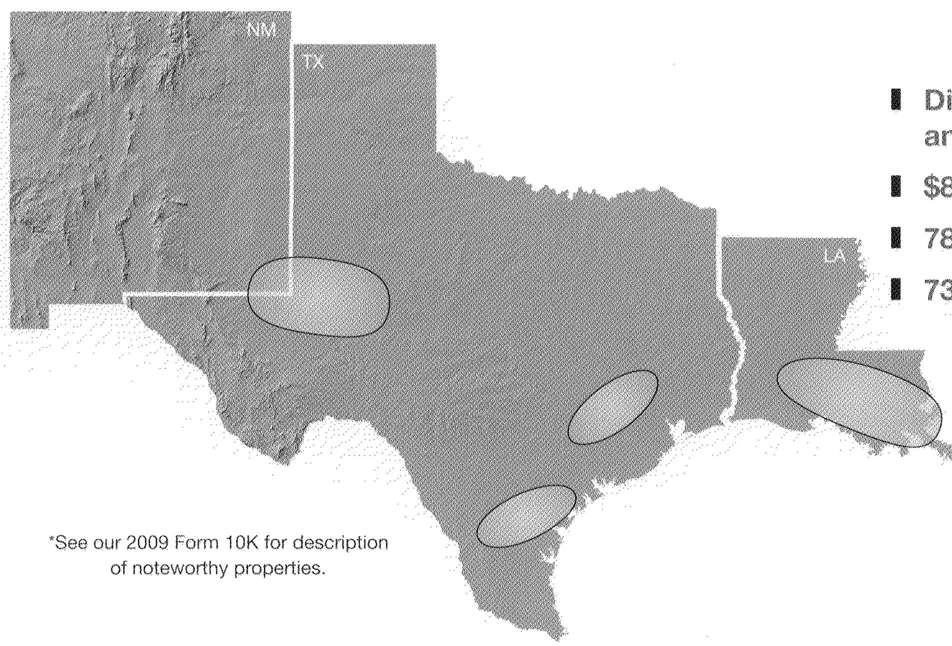
55.4 Bcf
11.4 MMBbl

* As of December 31, 2009, excludes interests in affiliated partnerships.

Focus Areas*



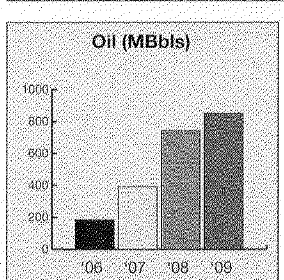
- Bakken and Williston Basin Oil
- $73 Million Project Inventory
- 22% of Total Production
- 27% of Proved Reserves

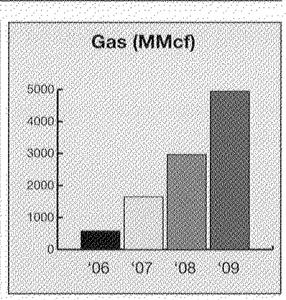


- Diversified Exploration and Development Projects
- $87 Million Project Inventory
- 78% of Total Production
- 73% of Proved Reserves

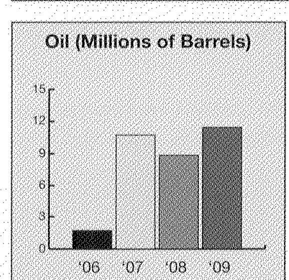
*See our 2009 Form 10K for description of noteworthy properties.

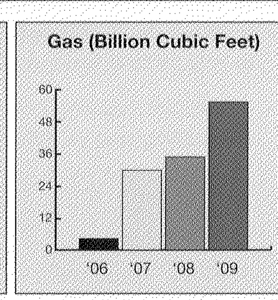
Annual Production



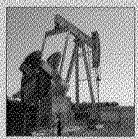


Proved Reserves at Year End





To Our Shareholders



Over the past three years our industry and the financial markets have experienced dramatic changes presenting numerous challenges for our Company. During this period oil prices climbed to almost $150 per barrel before plummeting to $33. Natural gas followed a similar path. The financial markets were exuberant and then all but collapsed. The banking industry was actively lending and then faced severe liquidity constraints. Nevertheless, last year amidst the low points in the commodity price cycle and financial markets, I reported that GeoResources was positioned to face the challenges of 2009. We did just that and achieved significant growth in our oil and gas reserves and production. Further, we reduced our operating costs dramatically and realized substantial earnings and cash flows. We pursued our strategy, continued with our capital expenditures and closed two significant acquisitions in our core areas. We increased our production 36% and our proved reserves 42%, which resulted in replacing 467% of our production. Further, we expanded our acreage positions and drilling inventory and, in my opinion, have further positioned the Company for continued profitable growth.

For the year ended December 31, 2009, we reported revenues of $80.4 million, net income of $9.8 million and adjusted EBITDAX of $48.2 million. As expected, these amounts were down somewhat from 2008, but we were able to offset significant price declines with production increases and cost reductions. While average realized crude oil prices were down 26% and average realized natural gas prices were down 51%, revenues were down only 15% and adjusted EBITDAX was down only 11%. We did an excellent job of reducing operating expenses. On an absolute basis, our lease operating expenses declined 18% and on a unit-of-production basis the decline was 40%. The vast majority of the reduction in operating expenses resulted from our re-engineering and development drilling activities and from high-grading our portfolio.

Our reserve and production profile, commodity price hedging strategy, cash flows and strong banking relationships allowed us to maintain our borrowing capacity in the storm of price reductions and tightening credit. Therefore, we were able to make significant acquisitions in our core areas in the early part of 2009 totaling approximately $60 million. These acquisitions added proved reserves, current production and additional drilling opportunities. We initially funded these acquisitions with our credit facility, and when the capital markets improved, we raised $33 million through an equity offering. These accomplishments further positioned the Company to exploit our properties, continue to expand our acreage and drilling portfolio, and pursue additional growth opportunities.

We believe an active acquisition market will exist in 2010. Accordingly, we will continue to pursue strategic acquisitions in seeking to accelerate profitable growth. Acquisitions may take the form of productive assets, corporate entities or acreage. We will continue with our business plan and not over-leverage the Company. We will not make acquisitions simply for the sake of reserve growth, and we will not abandon our core investment and operating principles.

Last year, I wrote that our management team has a track record of survival and delivering profitable growth. We have once again delivered and are committed to doing so in the future. Parts of this letter may sound the same as last year and that is specifically intended to acquaint new investors with our strategy and reiterate our principles to existing investors, our board and staff. So at the risk of redundancy, I state again that our business approach, which includes a combination of geologically and geographically diversified projects and a combination of acquisitions, development and exploration, has been tested by time. Further, we believe our strategy is preferable for the profitable growth of a small oil and gas company because:

- It is a proven strategy successfully employed by the GeoResources' management team in prior entities;
- It allows us to manage the multiple risks of oil and gas operations while providing shareholders with significant exposure to upside; and
- It gives us "staying power", which we have always believed is essential to mitigate the adverse impacts of fluctuating and volatile commodity price and financial markets.

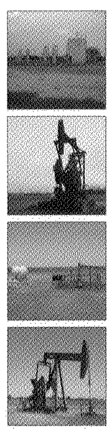
Operations

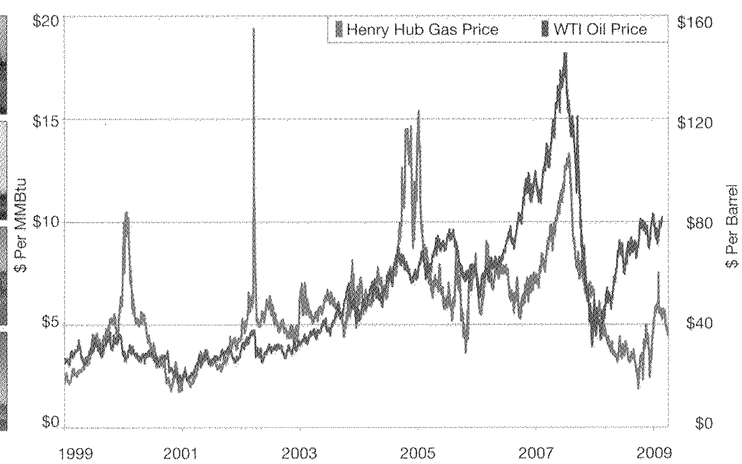
We operate the majority of our properties and often initiate projects and solicit industry or financial partners on a promoted basis. Field operations are important to us to contain costs and directly influence economic field development. Therefore we are quite selective when we participate in projects operated by others and also when choosing our non-operating partners.

During 2009, we continued our successful exploitation of the Austin Chalk formation in Giddings Field, Texas. Since this acquisition in early 2007, we have drilled and completed 14 wells with a 100% success rate. We increased our ownership in these properties and undeveloped acreage in 2009 and now have direct working interests averaging about 36%. We operate the properties and, in addition, we have a 30% general partner interest in an affiliated partnership which owns working interests averaging 56%. We continued leasing, and at present, the Company and its partnership control over 68,000 net acres. We have 22 more development locations, where our working interest ranges from 37% to 53%. We believe the acreage is prospective for the Yegua, Georgetown and Eagle Ford Shale formations.

We continued to increase our position in our non-operated Bakken Shale joint venture and now have 10% to 18% working interest in approximately 106,000 net acres. To date, 48 joint venture operated wells have been drilled with a 100% success rate. The general level of drilling activity has increased substantially from early 2009 with the improvement of oil prices and differentials. During the low price environment, we slowed our drilling and focused on adding acreage. At present the joint venture is running five drilling rigs and expect four to five rigs on a continuing basis.

Commodity Prices





Importantly, we have expanded our Bakken activities into an operated project, have leased more than 44,000 net acres and joined with certain industry partners for drilling and development. We have retained a significant operated working interest and expect to drill at least three wells by year end.

We also continue to pursue other smaller but important projects including but not limited to, secondary recovery operations in our Starbuck Field in North Dakota and our 3-D seismic project in St. Martinville Field in south Louisiana. Our working interests in both of these projects exceed 95%.

Thanks

Once again I want to thank our Board, officers and employees. Our progress is a direct result of their hard work and dedication. So, "Thank You" to our directors for their continued guidance and to our staff for their accomplishments and loyalty. Our management and staff are a cohesive group, and I am thankful to have the opportunity to work with these folks. Last year, in a dismal environment, I reminded our management and staff of the challenges ahead and urged them all to remain motivated and focused in order to deal effectively with the economic circumstances. As we progress through 2010, they remain motivated and focused to continue our profitable growth.

Frank A. Lodzinski

Chairman and Chief Executive Officer
March 30, 2010

Operational & Financial Highlights

(in thousands, except as otherwise indicated)	2009	2008	2007	2006
Proved Reserves Year-End [(A)]				
Oil (MBbls)	11,419	8,793	10,744	1,777
Natural Gas (MMcf)	55,436	34,796	29,810	4,218
Barrels of Oil Equivalent (MBoe)	20,659	14,592	15,712	2,480
Percent Developed	75%	80%	85%	86%
Percent Oil	55%	60%	68%	72%
Reserve/Production Ratio (Years)	12.3	11.8	13.6	8.9
Future Net Operating Income-undiscounted [(B)]	$ 408,272	$ 284,577	$ 704,146	$ 64,105
Discounted at 10% (before income tax) [(B)]	$ 217,591	$ 150,616	$ 381,991	$ 40,405
Price Used to Calculate Year-End Reserves [(B)]				
Oil ($/Bbls)	$ 61.18	$ 44.60	$ 96.01	$ 61.60
Natural Gas ($/Mcf)	$ 3.83	$ 5.62	$ 7.47	$ 5.48
Production (Net Sales Volume)				
Oil (MBbls)	851	743	392	184
Natural Gas (MMcf)	4,944	2,962	1,648	577
Barrels of Oil Equivalent (MBoe)	1,675	1,236	666	280
Percent Oil	51%	60%	59%	66%
Average Realized Prices for the Year				
Oil ($/Bbls)	$ 61.09	$ 82.42	$ 67.20	$ 54.61
Natural Gas ($/Mcf)	$ 3.97	$ 8.12	$ 6.19	$ 6.83
Financial Highlights				
Total Revenues	$ 80,428	$ 94,606	$ 40,115	$ 16,805
Adjusted EBITDAX [(C)]	$ 48,159	$ 54,150	$ 18,365	$ 8,721
Net Income Before Tax	$ 14,842	$ 21,291	$ 7,949	$ 4,280
Net Income [(D) (E)]	$ 9,775	$ 13,522	$ 3,069	$ 4,247
Total Assets	$ 304,297	$ 243,534	$ 240,358	$ 50,667
Long-Term Debt	$ 69,000	$ 40,000	$ 96,000	$ 5,000
Stockholders' Equity	$ 174,677	$ 140,995	$ 68,032	$ 23,660
Weighted Average Common Shares Outstanding-Diluted	16,559	15,751	12,405	4,858

(A) In April 2007, GeoResources, Inc. entered into a reverse merger with Southern Bay Oil & Gas L.P. and acquired a subsidiary of Chandler Energy, LLC and certain oil and gas assets. The Company was the legal acquirer, but for financial reporting purposes, the transaction was accounted for as a reverse merger and therefore 2006 represents the activities of Southern Bay.

(B) SEC perscribed price, prior to adjustments for transportation, quality, etc.

(C) Adjusted EBITDAX is income before income taxes, interest expense, depletion and depreciation, impairments, exploration expense, hedging gains and losses and non-cash compensation. Adjusted EBITDAX should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not in accordance with, nor superior to, generally accepted accounting principles, but provides additional information for evaluation of our operating performance.

(D) 2006 does not include any income tax expense as Southern Bay was a non-taxable entity.

(E) Includes a one-time tax accrual of $2.1 million in 2007 to reflect deferred taxes pursuant to generally accepted accounting principles.

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

Annual Report under Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year ended December 31, 2009

Commission File Number – 0-8041

GeoResources, Inc.

GEORESOURCES, INC.
(Exact name of registrant as specified in its charter)

Colorado
(State or other jurisdiction of incorporation or organization)

84-0505444
(I.R.S. Employer Identification No.)

110 Cypress Station Drive, Suite 220
Houston, Texas
(Address of principal executive offices)

77090-1629
(Zip code)

(281) 537-9920
(Registrant's telephone number, including area code)

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

Title of each class	Name of exchange on which registered
Common Stock, Par Value $0.01 Per Share	NASDAQ

Indicated by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
[ ] Yes [X] No

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files)
Yes [ ] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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. [ ]

Indicated by check mark whether the registrant is a large accelerated file, an accelerated file, a non-accelerated filer, or a smaller reporting company. (Check one):

Larger accelerated filer [ ]   Accelerated filer [X]

Non-accelerated filer [ ]   Smaller reporting company [ ]

Indicated by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2009: $74,756,000

Number of shares of the registrant's common stock outstanding at March 11, 2010: 19,712,862

DOCUMENTS INCORPORATED BY REFERENCE

Part III of this report incorporates certain portions of the definitive proxy materials of the registrant in respect of its 2010 Annual Meeting of Shareholders.

TABLE OF CONTENTS

Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this report, including, without limitation, statements regarding our business strategy, plans, objectives, expectations, intent, and beliefs of management, related to current or future operations are forward-looking statements. These statements are based on certain assumptions and analyses made by our management in light of its experience and its perception of historical trends, current conditions, expected future developments and other factors it believes to be appropriate. The forward-looking statements included in this report are subject to a number of material risks and uncertainties. Forward-looking statements are not guarantees of future performance and actual results; therefore, developments and business decisions may differ materially from those envisioned by the forward-looking statements.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to: changes in production volumes; our assumptions about oil and gas prices; operating costs and production; our ability to achieve growth in assets and revenues; worldwide supply and demand, which affect prices for oil and natural gas; the timing and extent of our success in discovering, acquiring, developing and producing oil and natural gas reserves; risks inherent in the operation of oil and natural gas wells; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; and conditions in the capital markets. See also "Risk Factors" in Item 1A of this report for factors that could cause results to differ materially from forward-looking statements.

CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms "we," "us," "our" or "ours" when used in this report refer to GeoResources, Inc., together with its consolidated operating subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this report:

After payout – With respect to an oil or natural gas interest in a property, refers to the time period after which the costs to drill and equip a well have been recovered.

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

Bbls/d or ***BOPD*** – barrels per day.

Bcf – Billion cubic feet.

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

Before payout – With respect to an oil and natural gas interest in a property, refers to the time period before which the costs to drill and equip a well have been recovered.

Behind-pipe reserves – Those reserves expected to be recovered from completion interval(s) not yet open but still behind casing in existing wells.

BOE – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

Carried interest – A contractual arrangement, usually in a drilling project, whereby all or a portion of the working interest cost participation of the project originator is paid for by another party in exchange for earning an interest in such project.

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.

Compression – A force that tends to shorten or squeeze, decreasing volume or increasing pressure.

DD&A – Depreciation, depletion and amortization.

Developed acreage – The number of acres which are allotted or assignable to producing wells or wells capable of production.

Development activities – Activities following exploration including the installation of facilities and the drilling and completion of wells for production purposes.

Development well – A well drilled within the proved area 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 economically.

Exploitation – The act of making oil and gas property more profitable, productive or useful.

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

Farm-in or ***Farm-out*** – An agreement whereunder the owner of a working interest in an oil and natural gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty and/or reversionary interest in the lease. The interest received by the assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

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.

GAAP – Generally accepted accounting principles in the United States of America.

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

Horizontal drilling – A drilling technique that permits the operator to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques that may, depending on horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Injection well – A well used to inject gas, water, or liquefied petroleum gas under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.

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

Mbtu (Mmbtu) – Used as a standard unit of measurement for natural gas and provides a convenient basis for comparing the energy content of various grades of natural gas and other fuels. One cubic foot of natural gas produces approximately 1,000 BTUs, so 1,000 cubic feet of gas is comparable to 1 MBTU. MBTU is often expressed as MMBTU, which is intended to represent a thousand BTUs.

Mcf – One thousand cubic feet.

Mcf/d – One thousand cubic feet per day.

Mcfe – One thousand cubic feet equivalent determined by using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids, which approximates the relative energy content of crude oil, condensate and natural gas liquids as compared to natural gas. Prices have historically been higher or substantially higher for crude oil than natural gas on an energy equivalent basis although there have been periods in which they have been lower or substantially lower.

MMcf – One million cubic feet.

MMcf/d – One million cubic feet per day.

MMcfe – One million cubic feet equivalent.

Net acres or net wells – The sum of the fractional working interests owned in gross acres or gross wells.

NGL's – Natural gas liquids measured in barrels.

NRI or ***Net Revenue Interests*** – The share of production after satisfaction of all royalty, oil payments and other non-operating interests.

Normally pressured reservoirs – Reservoirs with a formation-fluid pressure equivalent to 0.465 PSI per foot of depth from the surface. For example, if the formation pressure is 4,650 PSI at a depth of 10,000 feet, the pressure is considered to be normal.

Over-pressured reservoirs – Reservoirs with a formation fluid pressure greater than 0.465 PSI per foot of depth from the surface.

Plant products – Liquids generated by a plant facility; including propane, iso-butane, normal butane, pentane and ethane.

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

PV10% – The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices, as prescribed in the SEC rules, and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, depreciation, depletion and amortization, or Federal income taxes and discounted using and annual discount rate of 10%. PV10% many be considered a non-GAAP financial measure as defined by the SEC.

Primary recovery – The first stage of hydrocarbon production in which natural reservoir drives are used to recover hydrocarbons, although some form of artificial lift may be required to exploit declining reservoir drives.

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 exceeds production expenses and taxes.

Proved developed nonproducing reserves or ***PDNP*** – Proved developed nonproducing reserves are proved reserves that are either shut-in or are behind-pipe reserves.

Proved developed producing reserves or ***PDP*** – Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and able to produce to market.

Proved developed reserves – Proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods.

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

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

Proved undeveloped reserves or ***PUD*** – 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 well bore in another formation from that in which the well has been previously completed.

Reprocessing – Taking older seismic data and performing new mathematical techniques to refine subsurface images or to provide additional ways of interpreting the subsurface environment.

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.

Royalty interest – An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SEC – The U.S. Securities and Exchange Commission.

Secondary recovery – The use of water-flooding or gas injection to maintain formation pressure during primary production and to reduce the rate of decline of the original reservoir drive.

Shut-in reserves – Those reserves expected to be recovered from completion intervals that were open at the time of the reserve was estimated but were not producing due to market conditions, mechanical difficulties or because production equipment or pipelines were not yet installed.

Standardized Measure of Discounted Future Net Cash Flows – Present value of proved reserves, as adjusted to give effect to estimated future abandonment costs, net of estimated salvage value of related equipment, and estimated future income taxes.

3-D seismic – An advanced technology method of detecting accumulation of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

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.

Waterflooding – The secondary recovery method in which water is forced down injection wells laid out in various patterns around the producing wells. The water injected displaces the oil and forces it to the producing wells.

Working interest or **WI** – The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and share of production, subject to all royalties, overriding royalties and other burdens and to share in all costs of exploration, development operations and all risks in connection therewith.

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

PART I

Item 1. Business

Overview

GeoResources, Inc. (the "Company," "we" or "us"), a Colorado corporation, is an independent oil and gas company engaged in the acquisition and development of oil and gas reserves through an active and diversified program which includes purchases of reserves, re-engineering, development and exploration activities primarily focused in the Southwest, Gulf Coast and the Williston Basin areas of the United States. Our corporate headquarters and Southern Division operating offices are located in Houston, Texas, and our Northern Division operating office is located in Denver, Colorado. We also have an additional operating office for the Northern Division in Williston, North Dakota.

In April 2007, the Company merged with Southern Bay Oil & Gas, L.P. ("Southern Bay") and a subsidiary of Chandler Energy, LLC ("Chandler") and acquired certain Chandler-associated oil and gas properties in exchange for 10,690,000 shares of common stock (collectively, the "Merger"). At the time of the Merger, the former Southern Bay partners received approximately 57% of the outstanding common stock of the Company and thus, acquired voting control. Although GeoResources was the legal acquirer, for financial reporting purposes the Merger was accounted for as a reverse acquisition of GeoResources by Southern Bay and an acquisition of Chandler and its associated properties.

Since 2007, management of the Company has implemented a business strategy (as further discussed below) which includes acquisition, development and exploration activities in multiple basins and further includes geographically diverse projects. Accordingly, the Company was transformed from a small regional North Dakota-based company to a full scale exploration and production company with operations in multiple basins. As of December 31, 2009, we had an estimated 22,120 MBOE of proved reserves, associated with both our directly owned mineral interests (20,659 MBOE) and our partnership interests (1,461 MBOE). Our directly owned interests were approximately 55% oil and 75% developed. See Item 2 of this report for estimates of our oil and gas reserves at December 31, 2009. Our production for the year ended December 31, 2009 totaled 1,675 MBOE or 4,589 BOE per day of which 51% was oil.

Recent Developments

Acquisition and Divestitures

During 2009 we continued our drilling programs and expanded our acreage positions. We also acquired producing and undeveloped properties, principally in the Bakken Shale trend in the Williston Basin, North Dakota and in the Giddings field, Texas. A summary of our activities are as follows:

- In January 2009, we sold a producing property located in Louisiana to an unaffiliated party for $1.6 million. We recognized a gain of $1.3 million on this sale.

- In May 2009, we acquired producing wells and acreage in the Bakken Shale trend of the Williston Basin through an existing joint venture where we participate as a non-operator. We acquired a 15% interest in approximately 60,000 net acres, and also acquired 15% of varying working interests in 59 producing and productive wells. Our share of producing wells and undeveloped locations, at the time of acquisition, added approximately 486,000 BOE of proved reserves and numerous prospective locations. Including subsequent leasehold acquisitions, we now have working interests in the joint venture ranging from 10% to 18% in approximately 106,000 net acres. The acquisition cost was approximately $10.4 million. We funded the acquisition with borrowings from our senior secured revolving credit facility.

- In May 2009, we acquired certain oil and gas producing properties in Giddings field, Texas from an affiliated limited partnership for which we serve as the general partner. Prior to the acquisition, we had direct working interests in the properties ranging from about 6.5% to 7.8%. We now hold direct working interests in the producing wells ranging from approximately 34% to 37%. The acquired direct working interests totaled an estimated 25 Bcfe of proved reserves, 88% natural gas and 73% developed, with daily production, at the time of the transaction, totaling 10,625 Mcf and 85 Bbls of associated liquids. In addition, we increased our partnership interest from 2% to 30% amounting to an estimated 13.2 Bcfe. We remain the general partner of the partnership and operator of the properties. The acquisition also provided additional development opportunities and exposure to the potential upside associated with the Yegua, Georgetown and Eagle Ford Shale formations. The Interests were purchased for a net cash purchase price of $47.7 million. In addition, we acquired rights to certain post closing severance tax refunds which amounted to $2.4 million. We funded the acquisition with borrowings from our senior secured revolving credit facility.

- In August 2009, we received a distribution of proved undeveloped property and unproved acreage in the Giddings field from an affiliated limited partnership. The property was recorded at an estimated fair market value of $1.6 million.

- Beginning in October 2009, we initiated a leasing program in Williams County, North Dakota with the objective of expanding our Bakken shale activities and establishing an operated drilling and development program. As of March 3, 2010, we had acquired approximately 61,000 gross (42,000 net) acres and entered into agreements with industry partners to participate in future drilling and development activities. We expect to retain a 45% working interest, amounting to approximately 18,900 net acres to us, in a contractually specified area of mutual interest, with an average 37% net revenue interest. We are continuing to lease additional acreage. At present, we plan to drill at least three horizontal wells in the Middle Bakken formation prior to the end of 2010. Initial drilling is expected to commence in the summer of 2010. Recent activity in Williams County has confirmed commercial production in the Middle Bakken formation, which is our primary objective. Secondary objectives include the Three Forks, Madison and Red River formations.

Long-term Debt

On July 13, 2009, we entered into a Second Amended and Restated Credit Agreement ("Second Amended Credit Agreement"), which increased our previous credit facility from $200 million to $250 million and extended the term of the agreement to October 16, 2012. The initial borrowing base of the facility was $135 million, subject to redetermination on May 1 and November 1 of each year. On November 9, 2009 the borrowing base was increased to $145 million. The Second Amended Credit Agreement provides for interest rates at (a) LIBOR plus 2.25% to 3.00% or (b) the prime lending rate plus 1.25% to 2.00%, depending upon the amount borrowed and also requires the payment of commitment fees to the lender in respect of the unutilized commitments. The commitment rate is 0.50% per annum. We incurred costs of approximately $2.5 million to complete the amendment and we are amortizing these costs over the remaining life of the Second Amended Credit Agreement; the amortization is included in interest expense. The participating banks include: Wells Fargo Bank; Comerica Bank; BBVA Compass; U.S. Bank; Frost National Bank; Bank of Texas and Natixis.

Stock Issuances

On June 5, 2008, we issued 1,533,334 shares of our common stock and 613,336 warrants to purchase common stock to non-affiliated accredited investors pursuant to exemptions from registration under federal and state securities laws. The shares of common stock were sold for $22.50 per shares. The warrants have a term of five years ending June 5, 2013, with an exercise price $32.43 per share. The net proceeds of the offering were $32.2 million.

On December 1, 2009, we issued 3,450,000 shares of our common stock at $10.20 per share to investors pursuant to an offering registered with the SEC. The closing included the exercise in full of the underwriters' over-allotment option. Net proceeds from the offering were approximately $33.1 million after deducting the underwriters' discount and other offering expenses, and were used to reduce outstanding indebtedness under our Second Amended Credit Agreement. SMH Capital Inc. acted as Sole Book-Running and Lead Manager of the public offering; Rodman & Renshaw, LLC acted as Co-Lead Manager and C.K. Cooper & Company acted as Co-Manager.

Our Business Strategy

We implemented our business strategy upon the closing of the Merger in April 2007. Our strategy includes a combination of acquisition, re-engineering, development and exploration activities. We first focus on building reserves and cash flows and then we expand acreage, development and exploration inventory. Further, our strategy includes activities with geological and geographical diversity, intended to provide exposure to both crude oil and natural gas and across differing risk/return profiles.

Our business strategy includes:

- Acquiring oil and gas reserves through asset or corporate acquisitions or mergers;
- Expanding acreage and prospect inventory through internal generation of new projects and selective prospect participations with other capable oil and gas operators;
- Comprehensive field re-engineering, designed to increase and maintain production, lower per-unit operating expenses, and therefore improve field economics; and
- Development, exploitation and exploration activities intended to increase production and proved reserves.

Our fundamental operating and technical strategy is complemented by management's commitment to:

- Maintain a sound capital structure which provides the Company with a low cost of capital;
- Control capital, operating and administrative costs;
- Hedge a portion of production to provide a foundation of predictable cash flows to support development and exploration activities;
- Divest non-core assets to high-grade our property portfolio; and
- Promote industry and institutional partners into projects to manage risk and to lower net finding and development costs.

In the opinion of management, our strategy is appropriate for us because:

- It addresses multiple risks of oil and gas operations while providing shareholders with significant upside potential; and
- It results in "staying-power", which management believes is essential to mitigate the adverse impacts of volatile commodity prices and financial markets and it is the strategy employed successfully in prior entities formed, acquired and operated by management.

Each component of our business strategy and related matters are briefly discussed below.

Acquisitions and Divestitures – Acquisitions of oil and gas producing or undeveloped properties and acreage and corporate acquisitions are intended to allow us to assemble a portfolio of properties with the potential for meaningful economic returns from (1) the application of operational and technical attention, (2) development of non-producing reserves, and (3) realization of exploration upside. We seek to acquire oil and gas interests with the characteristics of manageable risks, fairly predictable production and value enhancement potential. An integral part of our strategy is to periodically divest certain non-core assets in order to high-grade our oil and gas property portfolio.

Development Activities – We also focus on development and exploitation of non-producing reserves. We conduct comprehensive regional studies to internally generate new projects and detailed field studies of existing properties which usually result in:

- New development projects (or targets) within our core operating areas;
- Development and exploration projects associated with existing properties, resulting from the integration of operations and reservoir engineering with geology and geophysics. When applicable, 3-D seismic technology is utilized. In these activities, our objective is to develop specific opportunities to recover bypassed or undeveloped reserves and define exploration potential; and
- Re-engineering projects with the intent to lower per-unit operating expenses and/or reduce field down-time. In addition, we seek to implement more efficient production practices in order to increase production and/or arrest natural field production declines. These practices are often deployed in fields in connection with or in anticipation of further field development activities such as installation of secondary recovery operations or additional drilling.

Exploration – Our exploration activities are intended to provide exposure to the significant upside potential; accordingly, we expect to continue to expand our exploration activities as our asset base increases. This strategy is designed to:

- Expand our inventory of substantive acreage and prospects;
- Fully develop acquired properties; and
- Realize substantial economic returns from exploration.

While we intend to dedicate a meaningful portion of our budget to exploration and drilling, as the geological objectives move to a higher risk and cost profile, industry or institutional partners will usually be solicited on a promoted basis where we sell part of the project in exchange for cash and/or a carried or reversionary interest.

Corporate Mergers and Acquisitions – As a distinct part of our overall strategy, we continue to pursue corporate merger and acquisition opportunities. Criteria for such acquisitions might include, but are not limited to:

- The potential to increase assets in a core area;
- The opportunity to increase our earnings and cash flow;
- Development and exploration potential;
- The ability to refinance debt and attract capital; and
- Realization of administrative savings.

In summary, we believe these diversified business strategies and methodical processes will maintain our reserve and production base and lead to growth in reserves, production, cash flow and consequently, in per share values.

Oil and Gas Exploration and Development

Our oil and gas exploration and production efforts are concentrated on oil and gas properties in our areas of operations. We typically generate prospects for our own exploitation, but when we believe a prospect may have substantial risk or cost, we may partially finance our drilling activities through the sale of participations to industry or institutional partners on a promoted basis, whereby we may earn working interests in reserves and production greater than our proportionate capital costs. For example, we may enter into farm-outs, joint ventures, or other similar types of cost-sharing arrangements to reduce our overall capital cost. The amount of interest retained by us in a cost-sharing arrangement varies widely and depends upon many factors, including the exploratory costs and the risks involved.

Marketing of Production

Our oil and gas production is marketed to third parties consistent with industry practices. Typically, oil is sold at the wellhead at field posted prices or market indices, plus or minus adjustments for quality or transportation. Natural gas is usually sold under a contract at a negotiated price based upon factors normally considered in the industry, such as quality, distance from the well to the pipeline and liquid hydrocarbon content, and prevailing supply/demand conditions.

Backlog Orders, Research and Development

Our oil and gas sales contracts and off-lease marketing arrangements are generally standard industry contracts with 30 to 90 day cancelation notice provisions. We do not have any contracts to supply crude oil or natural gas which exceed one year. We have not spent any material time or funds on research and development and do not expect to do so in the foreseeable future. In addition, as discussed elsewhere in this report, we have entered into long-term commodity hedge contracts to mitigate the effects of price declines of oil and natural gas.

Competition

In addition to being highly speculative, the domestic oil and gas business is highly competitive among many independent operators and major oil companies in the industry. Many competitors possess financial resources and technical facilities greater than those available to us and they may, therefore, be able to pay for more desirable properties or find more potentially productive prospects.

Environmental Regulations

Our operations are generally subject to numerous stringent federal, state and local environmental regulations under various acts including the Comprehensive Environmental Response, Compensation and Liability Act, the Federal Water Pollution Control Act, and the Resources Conservation and Recovery Act. For example, our operations are affected by diverse environmental regulations including those regarding the disposal of produced oilfield brines, other oil-related wastes, and additional wastes not directly related to oil and gas production. Additional regulations exist regarding the containment and handling of crude oil as well as preventing the release of oil into the environment. It is not possible to estimate future environmental compliance costs due in part, to the uncertainty of continually changing environmental initiatives. While future environmental costs can be expected to be significant to the entire oil and gas industry, we do not believe that our costs would be any more of a relative financial burden than others in our industry.

Foreign Operations and Export Sales

We do not have any interests, production facilities, or operations in foreign countries.

Employees

As of December 31, 2009, we had 50 full-time employees, 35 of which are management, technical and administrative personnel, and 15 are field employees. Contract personnel operate some of our producing fields under the direct supervision of our employees. We consider all relations with our employees to be good.

Available Information

We maintain a website at the address www.georesourcesinc.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. Through our website, we make available our Annual Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and amendments to these reports, as soon as reasonably practicable after we file such material with the SEC.

Item 1A. Risk Factors

Set forth below are risks with respect to our Company. Readers should review these risks, together with the other information contained in this report. The risks and uncertainties we have described in this report are not the only ones we face. Additional risks and uncertainties that are not presently known to us, or that we deem immaterial, may also adversely affect our business. Any of the risks discussed in this report that are presently unknown or immaterial, if they were to actually occur, could result in a significant adverse impact on our business, operating results, prospects and/or financial condition.

We are dependent upon the services of our chief executive officer and other executive officers.

We are dependent upon a limited number of personnel, including Frank A. Lodzinski, our Chief Executive Officer and President, and other management personnel and key employees. Failure to retain the services of these persons, or to replace them with adequate personnel in the event of their departure or termination, may have a material adverse effect on our operations. No employment agreements with any of our officers currently exist, but we may consider such agreements in the future. We have no key-man life insurance on the lives of any of our executive officers.

We must successfully acquire or develop additional reserves of oil and gas.

Our future production of oil and gas is highly dependent upon our level of success in acquiring or finding additional reserves. The rate of production from our oil and gas properties generally decreases as reserves are produced. We may not be able to acquire or develop oil and gas properties economically due to a lack of drilling success as well as lack of capital and inability to obtain adequate financing, which may be required to fund prospect generation, drilling operations and property acquisitions.

Intense competition in the oil and gas exploration and production segment could adversely affect our ability to acquire desirable properties prospective for oil and gas, as well as producing oil and gas properties.

The oil and gas industry is highly competitive. We compete with major integrated and independent oil and gas companies for the acquisition of desirable oil and gas properties and leases, for the equipment and services required to develop and operate properties, and in the marketing of oil and gas to end-users. Many competitors have financial and other resources that are substantially greater than ours, which could, in the future, make acquisitions of producing properties at economic prices difficult for us. In addition, many larger competitors may be better able to respond to factors that affect the demand for oil and natural gas production, such as changes in worldwide oil and natural gas prices and levels of production, the cost and availability of alternative fuels and the application of government regulations. We also face significant competition in attracting and retaining experienced, capable and technical personnel, including geologists, geophysicists, engineers, landmen and others with experience in the oil and gas industry.

We may be faced with shortages of personnel and equipment, thereby adversely affecting operations and financial results.

The oil and gas industry, as a whole, suffers from an aging workforce and a shortage of qualified and experienced personnel. Our operations and financial results may be adversely impacted due to difficulties in attracting and retaining such personnel within our Company or within companies that provide materials and services to the industry. Additional personnel are likely to be required in connection with our expansion plans, and the domestic oil and gas industry has in the past experienced significant shortages of qualified personnel in all areas of operations. Further, our expansion plans will likely require access to services and oil field equipment. Such equipment and operating personnel may be in short supply. The substantial decrease in commodity prices in 2008 has resulted in decreased drilling and construction activity in the industry and shortages of personnel and equipment has eased in 2009, but nevertheless shortages of qualified and experienced personnel still exist.

Volatile oil and natural gas prices could adversely affect our financial condition and results of operations.

The Company's most significant market risk is the pricing of crude oil and natural gas. Management expects energy prices to remain volatile and unpredictable. Moreover, oil and natural gas prices depend on factors that are outside of our control, including:

- Economic and energy infrastructure disruptions caused by actual or threatened acts of war, or terrorist activities particularly with respect to oil producers in the Middle East, Nigeria and Venezuela;
- Weather conditions, such as hurricanes, including energy infrastructure disruptions resulting from those conditions;
- Changes in the global oil supply, demand and inventories;
- Changes in domestic natural gas supply, demand and inventories;
- The price and quantity of foreign imports of oil;
- The price and availability of liquefied natural gas imports;
- Political conditions in or affecting other oil-producing countries;
- General economic conditions in the United Stated and worldwide;
- The level of worldwide oil and natural gas exploration and production activity;
- Technological advances affecting energy consumption; and
- The price and availability of alternative fuels.

Lower oil and natural gas prices not only decrease revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can economically produce. Lower prices also negatively impact estimates of our proved reserves. The Company has attempted to mitigate the risks associated with commodity price fluctuations by hedging a portion of production through price swaps and costless collars. However, substantial or extended declines in oil or natural gas prices may still materially and adversely affect our financial condition, results of operations, liquidity or ability to finance operations and planned capital expenditures.

Industry changes may adversely affect various financial measurements and negatively affect the market price of our common stock.

Although we believe that our business strategy has and will allow us to continue our growth and increase operating efficiencies, unforeseen costs and industry changes, as listed below, could potentially have an adverse effect on return of capital and earnings per share. Future events and conditions could cause any such changes to be significant, including, among other things, adverse changes in:

- Commodity prices for oil, natural gas and liquid natural gas;
- Reserve levels;
- Operating results;
- Capital expenditure obligations; and
- Production levels.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

Oil and natural gas exploration, drilling and production activities are subject to numerous operating risks including the possibility of:

- Blowouts, fires and explosions;
- Personal injuries and death;
- Uninsured or underinsured losses;
- Unanticipated, abnormally pressured formations;
- Mechanical difficulties, such as stuck oil field drilling and service tools and casing collapses; and
- Environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination.

Any of these operating hazards could cause damage to properties, serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs, and other environmental damages, which could expose us to liabilities.

We have hurricane associated risks in connection with our operations in the Texas and Louisiana Gulf Coast.

We have experienced in the past significant production curtailments due to hurricane damage. We could also be subject to production curtailments resulting from hurricane damage to certain fields or, even in the event that producing fields are not damaged, production could be curtailed due to damage to facilities and equipment owned by oil and gas purchasers, or vendors and suppliers, because a portion of our oil and gas properties are located in or near coastal areas of the Texas and Louisiana Gulf Coast.

Insurance may not fully recover potential losses.

Although we believe that we are reasonably insured against losses to wells and associated equipment, potential operational or hurricane related losses could result in a loss of our reserves and properties and materially reduce the funds available for exploration and development activities and acquisitions. The insurance market, in general, and the energy insurance market in particular, have experienced substantial cost increases over recent years, resulting from significant losses associated with hurricanes and commercial losses. To offset the significant cost increases we have increased our deductibles and made other modifications to coverage. We believe these changes are reasonable, considering both the underlying risks and the Company's size and financial standing. The potential for loss, however, cannot be accurately or reasonably predicted. If we incur substantial damages or liabilities that are not fully covered by insurance or are in excess of policy limits, then our business, results of operations, and financial condition could be materially affected. Also, as is customary in the oil and gas business, we do not carry business interruption insurance. In the future, it is also possible that we will further modify insurance coverage or determine not to purchase some insurance because of high insurance premiums.

If oil and gas prices decrease or exploration efforts are unsuccessful, we may be required to write-down the capitalized cost of individual oil and gas properties.

A writedown of the capitalized cost of individual oil and gas properties could occur when oil and gas prices are low or if we have substantial downward adjustments to our estimated proved oil and gas reserves, if operating costs or development costs increase over prior estimates, or if exploratory drilling is unsuccessful. A writedown could adversely affect the trading prices of our common stock.

We use the successful efforts accounting method. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves are discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed. All geological and geophysical costs on exploratory prospects are expensed as incurred.

The capitalized costs of our oil and gas properties, on a field-by-field basis, may exceed the estimated future net cash flows of that field. If so, pursuant to generally accepted accounting principles, we are required to record impairment charges to reduce the capitalized costs of each such field to its estimate of the field's fair market value, even though other fields may have increased in value. Unproved properties are evaluated at the lower of cost or fair market value. These types of charges will reduce earnings and shareholders' equity.

Revisions of oil and gas reserve estimates could adversely affect the trading price of our common stock. Oil and gas reserves and the standardized measure of cash flows represent estimates, which may vary materially over time due to many factors.

The market price of our common stock may be subject to significant decreases due to decreases in our estimated reserves, our estimated cash flows and other factors. Estimated reserves may be subject to downward revision based upon future production, results of future development, prevailing oil and gas prices, prevailing operating and development costs and other factors. There are numerous uncertainties and uncontrollable factors inherent in estimating quantities of oil and gas reserves, projecting future rates of production, and timing of development expenditures.

In addition, the estimates of future net cash flows from proved reserves and the present value of proved reserves are based upon various assumptions about prices and costs and future production levels that may prove to be incorrect over time. Any significant variance from the assumptions could result in material differences in the actual quantity of reserves and amount of estimated future net cash flows from estimated oil and gas reserves.

Our hedging activities may prevent us from realizing the benefits in oil or gas price increases.

In an attempt to reduce our sensitivity to oil and gas price volatility, we have, and will likely continue to, enter into hedging transactions which may include fixed price swaps, price collars, puts and other derivatives. In a typical hedge transaction, we may fix the price, a floor or a range, on a portion of our production over a predetermined period of time. It is expected that we will receive, from the counter-party to the hedge, payment of the excess of the fixed price specified in the hedge contract over a floating price based on a market index, multiplied by the volume of the production hedged. Conversely, if the floating price exceeds the fixed price, we would be required to pay the counter-party such price difference multiplied by the volume of production hedged. There are numerous risks associated with hedging activities such as the risk that reserves are not produced at rates equivalent to the hedged position, and the risk that production and transportation cost assumptions used in determining an acceptable hedge could be substantially different from the actual cost. In addition, the counter-party to the hedge may become unable or unwilling to perform its obligations under hedging contracts, and we could incur a material adverse financial effect if there is any significant non-performance. While intended to reduce the effects of oil and gas price volatility, hedging transactions may limit potential gains earned by us from oil and gas price increases and may expose us to the risk of financial loss in certain circumstances.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our financial condition and results of operations.

Our success will depend on the results of our exploitation, exploration, development and production activities. Oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Furthermore, many factors may curtail, delay or cancel drilling, including:

- Shortages of or delays in obtaining equipment and qualified personnel;
- Pressure or irregularities in geological formations;
- Equipment failures or accidents;
- Adverse weather conditions;
- Reductions in oil and natural gas prices;
- Issues associated with property titles; and
- Delays imposed by or resulting from compliance with regulatory requirements.

Existing debt and use of debt financing may adversely affect our business strategy.

We have used debt to fund a portion of our activities and we will likely use debt to fund a portion of our future acquisition activities. Any temporary or sustained inability to service or repay debt will materially adversely affect our results of operations and financial condition and will materially adversely affect our ability to obtain other financing.

We are obligated to comply with financial and other covenants in our existing Second Amended Credit Facility that could restrict our operating activities, and the failure to comply could result in defaults that accelerate the payment under our debt.

Our Second Amended Credit Facility generally contains customary covenants, including, among others, provisions:

- Relating to the maintenance of the oil and gas properties securing the debt; and
- Restricting our ability to assign or further encumber the properties securing the debt.
- All of our obligations under the Second Amended Credit Facility are secured by substantially all of our assets.

In addition, our Second Amended Credit Facility requires us to maintain financial covenants, including, but not limited to the following:

- A current ratio of not less than 1.0:1.0 excluding current hedge obligations;
- A funded debt to EBITDA ratio of not greater than 4.0:1.0; and
- An interest coverage ratio, which is the ratio of the EBITDA for the four most recently completed quarters ending on such date compared to the cash interest payments made for such fiscal quarters, of not less than 3.0:1.0.

As of the date of this report, we were in compliance with all such covenants. If we were to breach any of our debt covenants and not cure the breach within any applicable cure period, the Lender could require us to repay the debt immediately, and if the debt is secured, could immediately begin proceedings to take possession of substantially all of our properties. Any such property losses would materially and adversely affect our cash flow and results of operations.

Global financial and economic circumstances may have impacts on our business and financial condition that we currently cannot predict.

Global financial markets, as well as the global economic recession, may have an adverse impact on our business and our financial condition, and we may face challenges if conditions in the financial markets are inadequate to finance our activities at a reasonable cost of capital. While the current economic situation has improved over the prior year end any deterioration in financial markets (or changes in lending practices) could have a material adverse impact on our lenders. Furthermore, adverse economic circumstances could cause customers, joint owners or other parties with whom we transact business to fail to meet their obligations to us. Additionally, market conditions could have a materially adverse impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection. Also, worldwide economic conditions could lead to reduced demand for oil and natural gas, or lower prices for oil and natural gas, or both, which could have a material negative impact on our revenues, results of operations and financial conditions.

Changes in financial markets could result in significantly reduced access to public and private capital as well as substantially higher costs of capital if we are able to obtain capital.

Oil and gas activities are capital intensive. Historically, we have obtained equity and debt capital to fund our growth strategy. We may require additional equity capital in order to pursue our business strategy and avoid excessive debt levels. Financial markets often change abruptly and we may not be able to attract investors that would provide equity capital to us at all, or the costs to obtain such capital may be unreasonable. To the extent that we may attract capital, the costs of such capital could increase appreciably and such capital may take forms, such as preferred stock or convertible debt, which would be senior to our common stock. We believe that the ability to attract capital at reasonable costs is critical to our long-term growth strategy, particularly due to the depleting nature of oil and gas operations.

Our properties may be subject to influence by third parties that do not allow us to proceed with planned explorations and expenditures.

We are the operator of a majority of our properties, but for many of our properties we own less than 100% of the working interests. Joint ownership is customary in the oil and gas industry and is generally conducted under the terms of a joint operating agreement ("JOA"), where a single working interest owner is designated as the "operator" of the property. For properties where we own less than 100% of the working interest, whether operated or non-operated, drilling and operating decisions may not be within our sole control. If we disagree with the decision of a majority of working interest owners, we may be required, among other things, to postpone the proposed activity or decline to participate. If we decline to participate, we might be forced to relinquish our interest through "in-or-out" elections or may be subject to certain non-consent penalties, as provided in a JOA. In-or-out elections may require a joint owner to participate, or forever relinquish its position. Non-consent penalties typically allow participating working interest owners to recover from the proceeds of production, if any, an amount equal to 200% to 500% of the non-participating working interest owner's share of the cost of such operations.

Recent legislative proposals could materially lessen the economic viability of domestic exploration and production companies, including us.

The budgetary proposals of the Obama Administration, if enacted into law by Congress, could have a material adverse impact on the domestic oil and gas industry and on exploration and production companies in particular. The proposals would eliminate the so called "oil and gas company preferences" and raise other taxes on the industry. The proposed budget would eliminate tax mechanisms critical to capital formation for drilling, such as expensing of intangible drilling costs and eliminating the percentage depletion allowance, and if enacted, would have a significant adverse impact on domestic drilling for oil and natural gas. The proposed budget would also charge producers user fees for processing permits to drill on federal lands and increase royalty rates of minerals produced from federal lands. We cannot predict the outcome of the proposed U.S. Government budget, but the enactment of any of the proposals would likely adversely affect the domestic oil and gas exploration and production business by making future production more difficult and expensive, thereby lessening the economic viability of these companies, of which we are part.

There are a substantial number of shares of our common stock eligible for future sale in the public market. The sale of a large number of these shares could cause the market price of our common stock to fall.

There were 19,712,862 shares of our common stock outstanding as of March 11, 2010. Members of our management owned approximately 6,793,391 shares of our common stock, representing 34.5% of our outstanding common stock as of March 11, 2010. Sale of a substantial number of these shares would likely have a significant negative effect on the market price of our common stock, particularly if the sales are made over a short period of time. These shares may be sold publicly pursuant to an effective registration statement with the SEC.

If our stockholders, particularly management and their affiliates, sell a large number of shares of our common stock, the market price of shares of our common stock could decline significantly. Moreover, the perception in the public market that our management and affiliates might sell shares of our common stock could depress the market price of those shares.

Recovery of investments in acquiring oil and gas properties is uncertain.

We cannot assure that we will recover the costs we incur in acquiring oil and gas properties. While the acquisition and development of oil and gas properties is based on engineering, geological and geophysical assessments, such data and analysis is inexact and inherently uncertain. There can be no assurance that any properties we acquire will be economically produced or developed. Re-engineering operations pose the risk that anticipated benefits, which may include reserve additions, production rate improvements or lower recurring operating expenses, may not be achieved, or that actual results obtained may not be sufficient to recover investments. Drilling activities, whether exploratory or developmental, are subject to mechanical and geological risks, including the risk that no commercially productive reservoirs will be encountered. Unsuccessful acquisitions, re-engineering or drilling activities could have a material adverse effect on our results of operations and financial condition.

We cannot assure we would be able to achieve continued growth in assets, production or revenue.

There can be no assurance that we will continue to experience growth in revenues, oil and gas reserves or production. Any future growth in oil and gas reserves, production and operations will place significant demands on us and our management and personnel. Our future performance and profitability will depend, in part, on our ability to successfully integrate acquired properties into our operations, develop such properties, hire additional personnel and implement necessary enhancements to our management systems.

The nature of our business and assets may expose us to significant compliance costs and liabilities.

Our operations involving the exploration, production, storage, treatment, and transportation of liquid hydrocarbons, including crude oil, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment, operational safety, and related employee health and safety matters. Compliance with all of these laws and regulations may represent a significant cost of doing business. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory and remedial liabilities; the issuance of injunctions that may restrict, inhibit or prohibit our operations; or claims of damages to property or persons.

Compliance with environmental laws and regulations may require us to spend significant resources.

Environmental laws and regulations may: (1) require the acquisition of a permit before well drilling commences; (2) restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities; (3) prohibit or limit drilling activities on certain lands lying within wetlands or other protected areas; and (4) impose substantial liabilities for pollution resulting from past or present drilling and production operations. Moreover, changes in Federal and state environmental laws and regulations could occur and may result in more stringent and costly requirements which could have a significant impact on our operating costs. In general, under various applicable environmental regulations, we may be subject to enforcement action in the form of injunctions, cease and desist orders and administrative, civil and criminal penalties for violations of environmental laws. We may also be subject to liability from third parties for civil claims by affected neighbors arising out of a pollution event. Laws and regulations protecting the environment may, in certain circumstances, impose strict liability rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. Such laws and regulations may expose us to liability for the conduct of or conditions caused by others, or for our acts which were in compliance with all applicable laws at the time such acts were performed. We believe we are in compliance with applicable environmental and other governmental laws and regulations. In recent years, increased concerns have been raised over the protection of the environment. Legislation to regulate the emissions of greenhouse gases has been introduced in Congress, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues, such as the United Nations Climate Change Conference in Copenhagen in 2009. Also, the EPA has undertaken new efforts to collect information regarding greenhouse gas emissions and their effects. Recently, the EPA declared that certain greenhouse gases represent a danger to human health and proposed to expand its regulations relating to those emissions. To the extent that new laws or other governmental actions restrict the energy industry or impose additional environmental protection requirements that result in increased costs to the oil and gas industry, we could be adversely affected. We cannot determine to what extent our future operations and earnings may be affected by new legislations, new regulations or changes in existing regulations. There can be no assurance, however, that significant costs for environmental regulatory compliance will not be incurred by us in the future, thereby having an adverse effect on our ability to conduct our business profitably.

Our failure to successfully identify, complete and integrate future acquisitions of properties or business could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Item 1B. **Unresolved Staff Comments**

None.

Item 2. **Properties**

Offices

Our principal offices are located at 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, where we occupy approximately 15,800 square feet of office space. The lease provides for gross rent of $213,422 per year in the first year and escalates $7,900 per year until expiration on April 15, 2013. Our Northern Region office, consisting of approximately 3,600 square feet, is located at 475 17th Street, Suite 1210, Denver, Colorado 80202. The Denver office lease provides for gross rent of $77,190 per year for 2010 and expires on January 31, 2011. Our Williston office consists of approximately 4,000 square feet and is located at 1407 West Dakota Parkway, Williston, North Dakota 58801. The Williston office lease provides for gross rent of $24,000 per year for 2010 and expires on December 31, 2010. We currently expect to renew all of our office leases upon expiration.

Oil and Gas Reserve Information

All of our oil and gas reserves are located in the United States. Unaudited information concerning the estimated net quantities of all of our proved reserves and the standardized measure of future net cash flows from the reserves is presented in Note O to the Consolidated Financial Statements. The reserve estimates are based upon the reports of Cawley, Gillespie & Associates, Inc., an independent petroleum engineering firm. We have no long-term supply or similar agreements with foreign governments or authorities.

Set forth below is a summary of our oil and gas reserves as of December 31, 2009. All of our reserves are located in the United States. We did not provide any reserve information to any federal agencies in 2009 other than to the SEC.

	Oil (Mbbl)	Gas (Mmcf)	Present Value Discounted at 10% ($M) (1)
Proved developed	9,221	38,138	$ 182,580
Proved undeveloped	2,198	17,298	35,011
Total Proved	11,419	55,436	$ 217,591

Oil and Gas Reserve Quantities

	Oil (Mbbl)	Gas (Mmcf)
Proved reserve quantities, January 1, 2009	8,793	34,796
Purchases of minerals-in-place	586	25,728
Sales of minerals-in-place	(59)	(80)
Extensions and discoveries	972	9,227
Production	(851)	(4,944)
Revisions of quantity estimates	1,978	(9,291)
Proved reserve quantities, December 31, 2009	11,419	55,436
Proved developed reserve quantities January 1, 2009	7,522	25,025
December 31, 2009	9,221	38,138

(1) Present Value Discounted at 10% ("PV10") is a Non-GAAP measure that differs from the GAAP measure "standardized measure of discounted future net cash flows" in that PV10 is calculated without regard to future income taxes. Management believes that the presentation of PV10 value is relevant and useful to our investors because it presents the estimated discounted future net cash flows attributable to our estimated proved reserves independent of our income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to our reserves. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, we believe the use of a pre-tax measure provides greater comparability of assets when evaluating companies. For these reasons, management uses, and believes the industry generally uses, the PV10 measure in evaluating and comparing acquisition candidates and assessing the potential return on investment related to investments in oil and natural gas properties.

PV10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. For presentation of the standardized measure of discounted future net cash flows, please see "Note O: Supplemental Financial Information for Oil and Gas Producing Activities - Unaudited" in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report. The table below ("Non-GAAP Reconciliation") provides a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

Partnership Operations and Reserves as of December 31, 2009 (not included above):

The reserve quantities and values set forth above do not include our interest in two affiliated partnerships.

We hold a 30% partnership interest in SBE Partners, LP ("SBE Partners") which owns interests in the Giddings field (as discussed further below in Noteworthy Properties). In addition, we hold direct working interests in producing oil and gas properties located throughout Oklahoma and we also hold the general partner interest in OKLA Energy Partners, LP ("OKLA") which owns a larger interest in those same producing oil and gas properties. Our 2% partnership interest in OKLA reverts to 35.66% if the limited partner realizes a contractually specified rate of return.

The following table represents our estimated share (excluding our reversionary interests) of the affiliated partnerships' reserves and estimated present value of future net income discounted at 10% (in thousands), using SEC guidelines.

	Affiliated Partnership Reserves		
	Oil (Mbbl)	Gas (Mmcf)	Present Value Discounted at 10% ($M) [1]
Proved developed	45	7,821	$ 10,293
Proved undeveloped	10	613	379
Total	55	8,434	$ 10,672

<u>Non-GAAP Reconcilation</u>

The following table reconciles our direct interest in oil and gas reserves (in thousands):

Present value of estimated future net revenues (PV10)	$ 217,591
Future income taxes, discounted at 10%	(43,491)
Standardized measure of discounted future net cash flows	$ 174,100

The following table reconciles our indirect interest, through our affiliated partnerships, in oil and gas reserves (in thousands):

Present value of estimated future net revenues (PV10)	$ 10,672
Future income taxes, discounted at 10%	(3,337)
Standardized measure of discounted future net cash flows	$ 7,335

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of the estimates, as well as economic factors such as change in product prices, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates.

Proved Undeveloped Reserves

From December 31, 2008 to December 31, 2009, our proved undeveloped reserves ("PUDs") increased 75% from 2,900,000 BOE to 5,081,000 BOE, or an increase of 2,181,000 BOE. This increase in PUDs was attributable to successful drilling activity and property acquisitions made during 2009 in the Bakken Shale trend in North Dakota and the Giddings field in Texas. These PUD increases were partially offset by approximately 1,000,000 BOE in PUDs that were converted into proved developed reserves due to the approximately 22 gross proved undeveloped well locations that were drilled and placed on production during 2009. We incurred $11,400,000 in capital expenditures to drill and bring these 22 PUD locations to production.

The quantities of PUDs that remain undeveloped after having disclosed as proved undeveloped reserves for a period of five years or more are zero as of December 31, 2009.

Preparation of Reserve Estimates

We maintain adequate and effective internal controls over our reserve estimation process as well as the underlying data upon which reserves estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with engineers, geologists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in Internal Controls – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, production taxes and field level commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated in the reserves database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firm, Cawley, Gillespie & Associates, Inc. ("CG&A"), meets with our technical personnel to review field performance and future development plans in order to further verify their validity. Following these reviews the reserve database is furnished to CG&A so that they can prepare their independent reserve estimates and final report. Access to our reserve database is restricted to specific members of the reservoir engineering department.

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Robert Ravnaas, Executive Vice President. Mr. Ravnaas is a State of Texas Licensed Professional Engineer. See Exhibit 23.2 of this report for the Report of Cawley, Gillespie & Associates, Inc. and further information regarding the professional qualifications of Mr. Ravnaas.

Net Oil and Gas Production, Average Price and Average Production Cost

The net quantities of oil and gas produced and sold by us for each of the three years ended December 31, the average sales price per unit sold and the average production cost per unit are presented below.

		2009		2008		2007
Oil Production (MBbls)		851		743		392
Gas Production (MMcf)		4,944		2,962		1,648
Total Production (MBOE)*		1,675		1,236		667
Average sales price (net of hedging):						
Oil per Bbl	$	61.09	$	82.42	$	67.20
Gas per Mcf	$	3.97	$	8.12	$	6.19
BOE	$	42.76	$	68.96	$	54.74
Production cost per BOE	$	11.20	$	18.53	$	16.24

* Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (1 BOE).

Our production is sold to large petroleum purchasers. Due to the quality and location of our crude oil production, we may receive a discount or premium from index prices or "posted" prices in the area. Our gas production is sold primarily to pipelines and/or gas marketers under short-term contracts at prices which are tied to the "spot" market for gas sold in the area.

In 2009, one purchaser accounted for 17% of our consolidated oil and gas revenues, two purchasers accounted for 15% each of our consolidated oil and gas revenues, and one more accounted for 11%. In 2008, one purchaser accounted for 16% of our consolidated oil and gas revenues, two more accounted for 11% each and two purchasers accounted for 10% each of our consolidated oil and gas revenues. In 2007, two purchasers accounted for 17% and 14% of our consolidated oil and gas revenues. No other single purchaser accounted for 10% or more of our oil and gas revenues in 2009, 2008, or 2007. There are adequate alternate purchasers of our production such that we believe the loss of one or more of the above purchasers would not have a material adverse effect on our results of operations or cash flows.

Gross and Net Productive Wells

As of December 31, 2009, our total gross and net productive wells were as follows:

Productive Wells *

Oil		Gas		Total	
Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
653.0	262.2	447.0	202.4	1,100.0	464.6

* A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractions of working interests we own in gross wells. Productive wells are producing wells plus shut-in wells we deem capable of production. Horizontal re-entries of existing wells do not increase a well total above one gross well.

Gross and Net Developed and Undeveloped Acres

As of December 31, 2009, we had total gross and net developed and undeveloped leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated by state regulatory authorities.

Gross acres are those acres in which working interest is owned. The number of net acres represents the sum of fraction working interests we own in gross acres.

	Developed		Undeveloped		Total	
State	Gross	Net	Gross	Net	Gross	Net
Texas	85,200	47,149	27,093	14,162	112,293	61,311
N. Dakota	47,613	19,952	101,915	31,253	149,528	51,205
Colorado	7,049	5,119	47,188	31,556	54,237	36,675
Oklahoma	53,933	10,459	595	-	54,528	10,459
Alabama	42,480	21,240	-	-	42,480	21,240
Louisiana	31,921	11,070	4,277	2,127	36,198	13,197
Montana	8,891	6,393	14,343	12,277	23,234	18,670
All Others	4,796	3,686	80	52	4,876	3,738
Total	281,883	125,068	195,491	91,427	477,374	216,495

Exploratory Wells and Development Wells

Set forth below for the three years ended December 31, is information concerning the number of wells we drilled during the years indicated.

	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive or Dry Wells Drilled
Year	Productive	Dry	Productive	Dry	
2007	1.97	-	4.27	-	6.24
2008	0.09	1.00	9.72	1.96	12.77
2009	-	0.12	5.61	-	5.73

During 2009 we also drilled 4 gross (3.87 net) service wells to be used in conjunction with the water flood project at our Starbuck Madison Unit and Southwest Starbuck field in Bottineau County North Dakota.

Present Activities

At March 11, 2010, we had 28 gross (3.72 net) wells in the process of drilling or completing.

Supply Contracts or Agreements

As of December 31, 2009, we were not obligated to provide any fixed or determinable quantities of oil and gas in the future under any existing contracts or agreements, beyond the short-term contracts customary in division orders and off lease marketing agreements with the industry. In March, 2009, we entered into a forward sales contract for a portion of the crude oil sales on several of our Northern Region properties. The contract obligates us to sell 300 Bbls/d at a fixed price of $40.80. The contract term began April, 2009 and runs through March, 2010. We also engage in hedging activities as discussed in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Description of Noteworthy Properties

We are the operator of properties containing approximately 80% of our proved oil and gas reserves. As operator we are able to directly influence exploration, development and production operations. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price fluctuations, and thus provide a foundation for our technical staff to further develop our existing properties and also generate new projects that we believe have the potential to increase our share value. We believe that many of our existing fields have additional exploration and exploitation opportunities. As common in the industry we participate in non-operated properties but are selective; our non-operating participation decisions are dependent on the technical and economic nature of the projects and the operating expertise and financial standing of the operators. The following is a description of certain of our noteworthy operated and non-operated producing oil and gas properties.

Bakken Shale Trend, Williston Basin – Our Williston Basin, Bakken Trend properties are located in Mountrail County and the adjacent counties of North Dakota. As of December 31, 2009, we owned working interests in about 106,000 gross acres. To date, our principal drilling has been conducted through a joint venture with Slawson Exploration Company, but we also participate in this area with several other operators. We have varying working interests in the properties ranging from 10% to 18%. Through the end of 2009, we have realized a 100% success rate with 41 joint venture wells drilled by the operator. We also have nominal interests in over 120 wells that are producing or are in various stages of completion with other operators. Our joint venture continues to acquire acreage in this expanding play and is currently running five drilling rigs. Pending economic conditions we expect to continue to run 4-5 drilling rigs. The majority of our wells have been and are expected to be drilled on 640 acre spacing units. In our view, the economics are attractive and acreage can be "proved up" and placed on production on an expedited basis. However, we are scheduling 1,280 acre (and some larger) spacing units and have numerous locations which may result in or require larger spacing units. In addition, consistent with our business strategy of expanding acreage positions with growth, beginning in October 2009, we initiated a significant leasing program in Williams County, North Dakota with the objective of establishing a significant operated drilling program. We also solicited industry partners to participate in the project on a promoted basis. As of March 3, 2010, we have acquired approximately 61,000 gross (42,000 net) acres and entered into agreements with industry partners to participate in future drilling and development activities. We expect to retain a 45% working interest, amounting to approximately 18,900 net acres to the Company, in a contractually specified area of mutual interest, with an average 37% net revenue interest. We are continuing to lease additional acreage in this area. Initial drilling is expected to commence in the summer of 2010. For the quarter ended December 31, 2009, the production net to our interest in the Bakken Trend was approximately 728 BOE/day and was approximately 95% oil.

RipRap Coulee Field - This field is a Bakken Shale play in eastern Montana. It involves horizontal drilling at vertical depths of about 10,000 feet. Currently, we own 997 gross (498 net) acres in this prospect.

Starbuck Madison Unit and Southwest Starbuck Madison Unit – These properties are located in Bottineau County, North Dakota. The Starbuck Madison Unit includes 6,619 gross (6,354 net) acres and water-flood operations are underway. This unit includes 14 gross producing wells producing from the Mississippian Madison interval and six active injection wells. We operate the unit and have an average working interest of 96% and an average net revenue interest of 81%. Recent production increases are believed to be initial secondary recovery responses. The flood design includes two productive zones, the Midale (Mississippian Charles) and the Berentson (Mississippian Charles B-1) zone, which are being flooded separately. The Starbuck Midale has produced 584,000 barrels of oil and the Berentson has produced 754,000 barrels on primary recovery, for total field production of 1,267,000 barrels of oil. We also have successfully unitized the Southwest Starbuck Madison Unit which includes 560 gross acres. In this unit, we have a 98% working interest, a 75% net revenue interest and have completed the initial phase of water flood operations in connection with phase two of the larger Starbuck Madison Unit. For the quarter ended December 31, 2009, the production net to our interest from these two units was approximately 65 BOE/day and was 100% oil. Production is expected to increase should flood response be successful.

Chittim Field – We have 12,822 gross (6,411 net) acres in this field, located in Maverick County, Texas. The field presently produces out of the Glen Rose interval and the upside potential includes an additional three proved and probable undeveloped locations. The Maverick Basin, however, has additional plays and targets including the Pearsall and Eagle Ford shale. We have included in our capital budget one horizontal offset well to a vertical Pearsall well that produced. We believe horizontal drilling and advanced completion techniques offer the potential to make the Pearsall meaningful to us. The commercial viability of the Eagle Ford shale is currently unknown but there is significant activity in the area. We will monitor the drilling and development efforts of other operators before we commit drilling dollars to development. Our acreage is held by production and therefore, we have no pending lease obligations or expirations. For the quarter ended December 31, 2009, the production net to our interest in this field was approximately 989Mcfe/day and was approximately 98% natural gas.

Giddings Field – Our Giddings field properties are located in Brazos, Burleson, Fayette, Grimes, Lee, Montgomery and Washington Counties, Texas. We operate all of these properties, which consist of 66 gross wells that are producing from the Cretaceous Austin Chalk interval. All of these wells are horizontal producers that initially flow at high rates and subsequently produce through rod pumps, compression, and other production methods. We have an average direct working interest of 35% and a net revenue interest of 27% in this field. In Grimes County, however, where the majority of our production and development activity is, we have an average direct working interest of 37% and net revenue interest of 30%. In addition, we are the general partner and hold an interest of 30% in an affiliated limited partnership which owns an average 56% working interest with an average 43% net revenue interest in Giddings field. Our acreage position is 35,804 net acres, with approximately 29,406 net acres held directly and approximately 6,398 net acres held through our interest in the limited partnership. For the quarter ended December 31, 2009, the production net to our interest in Giddings field was approximately 11,515 Mcfe/day and was approximately 98% natural gas. An additional 8,212 Mcfe/day (which was approximately 98% gas) was attributable to our share of the limited partnership.

The net quantities of oil and gas produced and sold by us in Giddings field for each of the three years ended December 31, the average sales price per unit sold and the average production cost per unit are presented below:

	2009	2008	2007
Oil Production (MBbls)	8	2	2
Gas Production (MMcf)	3,361	928	613
Total Production (Mmcfe)*	3,410	940	626
Average sales price (net of hedging):			
Oil per Bbl	$ 64.84	$ 96.77	$ 70.35
Gas per Mcf	$ 2.91	$ 7.71	$ 5.97
Mcfe	$ 3.02	$ 7.81	$ 6.09
Production cost per Mcfe	$ 0.31	$ 0.33	$ 0.33

*Mcfe have been calculated on the basis of one barrel of oil is equivalent to six thousand cubic feet of natural gas.

In November 2009, we recommenced our successful exploitation of the Austin Chalk Formation in Giddings field, in Grimes County, Texas. The Hutto Unit #1-H, which was a planned 7,800 foot single lateral location, was spud on November 6, 2009. We are the operator and hold a 52% working interest in this well. This location and the next two or three planned drilling locations will be on the northwest side of our acreage block where we expect the reserves to be more "oily" and produce approximately 50% oil and liquids. Through December 31, 2009, we have drilled 14 Austin Chalk wells and achieved a success rate of 100%. Our present drilling inventory for this field includes 22 proved undeveloped and probable locations. We continue to acquire additional acreage. Our direct working interest in our inventory of planned drilling location varies from 37% to 53%. At present, we expect to sequentially drill all locations with a single drilling rig, but we may accelerate development pending continued success and favorable commodity prices.

There has been significant exploration activity in regional proximity to our large acreage position in Grimes County, Texas, including a shallow Yegua formation gas discovery, which we believe would be prospective to our acreage and justify a 3-D seismic program. We believe that the deeper Eagle Ford shale which underlies the Austin Chalk may present us with similar opportunities. The Eagle Ford shale is being drilled and evaluated by a number of substantially larger independents.

South Texas – Our south Texas fields include Odem field, located in San Patricio County and Driscoll field, located in Duval County. Productive formations include the Frio/Miocene and Jackson/Yegua intervals. The fields produce with the aid of rod pumps, gas lift and low pressure gathering systems. We operate these fields and our working interests in them range from 44% to 98%; our net revenue interests range from 35% to 86%. For the quarter ended December 31, 2009, the production net to our interest in these fields was approximately 309 BOE/day (62% oil).

West Texas – Our west Texas and New Mexico fields include Harris field located in Gaines County, Texas; our MAK field, located in Andrews County, Texas, and other fields located in Eddy and Lea Counties, New Mexico. Productive formations include the San Andres, Spraberry, Seven Rivers, Queen and Grayburg intervals. The fields produce with the aid of rod pumps. We operate these fields and our working interests in them range from 68% to 100% and our net revenue interests range from 52% to 78%. For the quarter ended December 31, 2009, the production net to our interests from these properties was approximately 189 BOE/day and was approximately 95% oil.

Eloi Bay Field Complex – Our Eloi Bay complex is located in Louisiana state waters offshore St. Bernard Parish, Louisiana in 5 to 10 feet of water. This non-operated complex has 46 gross producing wells. At present, 8,074 gross (4,352 net) acres are held by production. Our working interests in these wells vary between 12% and 50%. Across the complex as a whole, our average working interest is 46% and our average net revenue interest is 39%. In addition to the proved production, this field has numerous behind-pipe opportunities due to multiple stacked sand reservoirs along with four proved undeveloped locations, which are above existing production. Other operators have had drilling success and established deeper production in the area. We have budgeted funds for the acquisition and reprocessing of 3-D seismic throughout the field and certain surrounding acreage to define prospective opportunities which may exist. For the quarter ended December 31, 2009, the production net to our interests in the complex was approximately 345 BOE/day and was approximately 100% oil.

Quarantine Bay Field – Our Quarantine Bay field is located in Louisiana State waters offshore Plaquemines Parish, Louisiana in 6 to 15 feet of water. This non-operated field has 31 gross producing wells completed above 10,500 foot depth. All of the wells produce with the aid of gas lift equipment. We have an average working interest in these wells and production facilities of 7% and an average net revenue interest of 5%. For the quarter ended December 31, 2009, the production net to our interest in this field was approximately 45 BOE/day and was approximately 100% oil. While our current share of production is negligible, the production is holding a considerable amount of acreage with exploration potential. We hold 14,535 gross (1,281 net) acres above 10,500 feet and 5,214 net acres below that depth. Upside in the shallow reservoirs in this field consists of numerous behind-pipe opportunities due to the multiple stacked sand reservoirs, along with proved undeveloped and rate acceleration locations in the depths above 10,500 feet. We believe deeper formations provide exploration potential and we have a 33% working interest, with a 24.75% net revenue interest below 10,500 feet. The operator acquired 35 square miles of 3-D seismic data to image and define prospect leads primarily below 10,500 feet. Schlumberger was engaged to reprocess the 3-D seismic data and provide initial interpretive geological and geophysical services. Geophysical and subsurface evaluation is continuing and several prospects have been defined, the majority of which are on acreage that is held by production operations.

St. Martinville Field – Our St. Martinville field is located in St. Martin Parish, Louisiana. The field consists of 16 gross producing wells, which produce from numerous Miocene sand intervals. The wells are on rod-pump or electric submersible pumps. We operate the field and have an average working interest of 97%. We own the majority of the minerals resulting in a net revenue interest of approximately 91%. We are currently interpreting a 3-D seismic survey over this field that was shot and processed in late 2009. We believe the field has development and exploration potential. For the quarter ended December 31, 2009, the production net to our interest in this field was approximately 209 BOE/day and was approximately 100% oil.

Title to Properties

It is customary in the oil and gas industry to make a limited review of title to undeveloped oil and gas leases at the time they are acquired. It is also customary to obtain more extensive title examinations prior to the commencement of drilling operations on undeveloped leases or prior to the acquisition of producing oil and gas properties. With respect to the future acquisition of both undeveloped and proved properties, we plan to conduct title examinations on such properties in a manner consistent with industry and banking practices. We have obtained title opinions, title reports or otherwise conducted title investigations covering substantially all of our producing properties and believe we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, overriding royalty interests, and other burdens which we believe do not materially interfere with the use or affect the value of such properties. Substantially all of our oil and gas properties are and may continue to be mortgaged to secure borrowings under bank credit facilities (see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources").

Item 3. <u>Legal Proceedings</u>

We are not party to, nor any of our properties subject to, any material pending legal proceedings. We know of no material legal proceedings contemplated or threatened against us.

Item 4. <u>Reserved</u>

Executive Officers of the Registrant

The following table sets forth certain information as of March 11, 2010, regarding the executive officers of GeoResources, Inc.:

Name	Age	Position(s) with the Company
Frank A. Lodzinski	60	President and Chief Executive Officer
Collis P. Chandler	41	Executive Vice President and Chief Operating Officer - Northern Region
Francis M. Mury	58	Executive Vice President and Chief Operating Officer - Southern Region
Robert J. Anderson	48	Vice President, Business Development, Acquisitions and Divestitures
Howard E. Ehler	65	Vice President and Chief Financial Officer

Frank A. Lodzinski has been President, Chief Executive Officer and Director of the Company since the Merger on April 17, 2007. He has 38 years of oil and gas industry experience. In 1984, he formed Energy Resource Associates, Inc., which acquired controlling interests in oil and gas properties and limited partnerships. Subsequently, certain assets were sold and in 1992 the partnership interests were exchanged for common shares of Hampton Resources Corporation (NASDAQ: "HPTR"), which Mr. Lodzinski joined as president. In 1995, Hampton was sold to Bellwether Exploration Company. In 1996, he acquired Cliffwood Oil & Gas Corporation and in 1997, Cliffwood shareholders acquired controlling interest in Texoil, Inc. (NASDAQ: "TXLI"), where Mr. Lodzinski served as CEO and President. In 2001, Texoil was sold to Ocean Energy, Inc. Mr. Lodzinski was then appointed CEO and President of AROC, Inc., which was a financially distressed company. He and his management team took the company private, recapitalized the company and implemented a turn-around and liquidation plan. In late 2003, AROC completed an asset monetization, which resulted in a sizable liquidity event for preferred and common shareholders. Mr. Lodzinski subsequently formed Southern Bay Energy, LLC, and in 2005 acquired certain assets from AROC. Mr. Lodzinski is a certified public accountant and holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

Collis P. Chandler, III has been Executive Vice President and Chief Operating Officer - Northern Region and Director of the Company since the Merger on April 17, 2007. He has been President and sole owner of Chandler

Energy, LLC since its inception in July 2000. From 1988 to July 2000, Mr. Chandler served as Vice President of The Chandler Company, a privately-held exploration company operating primarily in the Rocky Mountains. His responsibilities over the 12-year period included involvement in exploration, prospect generation, acquisition, structure and promotion as well as direct responsibility for all land functions including contract compliance, lease acquisition and administration. Mr. Chandler received a Bachelor of Science Degree from the University of Colorado, Boulder, in 1992.

Francis M. Mury has been Executive Vice President and Chief Operating Officer - Southern Region of the Company since the Merger on April 17, 2007. He has been active in the oil and gas industry since 1974. He was employed by AROC, Inc. as Executive Vice President from May 2001 through December 2004. Since January 2005, he has been employed by Southern Bay Energy LLC as Executive Vice President. Mr. Mury worked for Texaco, Inc. from July 1974 through March 1979, ending his tenure there as a petroleum field engineer. From April 1979 through December 1985, he worked for Wainoco Oil & Gas as a production engineer and drilling superintendent. From January 1986 to November 1989 he worked for Diasu Oil & Gas as an operations manager. He has worked with Mr. Lodzinski since 1989, including at Hampton Resources Corporation, where he served as Vice President – Operations from January 1992 through May 1995, and Texoil, Inc., where he served as Executive Vice President from November 1997 through February 2001. His experience extends to all facets of petroleum engineering, including reservoir engineering, drilling and production operations and further into petroleum economics, geology, geophysics, land and joint operations. Geographical areas of experience include the Gulf Coast (offshore and onshore), east and west Texas, Mid-Continent, Florida, New Mexico, Oklahoma, Wyoming, Pennsylvania and Michigan. Mr. Mury received a degree in Computer Science (1974) from Nicholls State University, Thibodeaux, Louisiana.

Robert J. Anderson has been Vice President, Business Development, Acquisitions and Divestitures of the Company since the Merger on April 17, 2007. He is a Petroleum Engineer and has been active in the oil and gas industry since 1987 with diversified domestic and international experience for both major oil companies (ARCO International/Vastar Resources) and independent oil companies (Hunt Oil/Huguton Energy/Anadarko Petroleum). From October 2000 through February 2004, he was employed by Anadarko Petroleum Corporation as a petroleum engineer. From March 2004 through December 2004 he was employed by AROC, Inc. as Vice President, Acquisitions and Divestitures. He joined Southern Bay Energy, LLC in January 2005 as Vice President, Acquisitions and Divestitures. His professional experience includes acquisition evaluation, reservoir and production engineering and field development, and project economics, budgeting and planning. Mr. Anderson's domestic acquisition and divestiture experiences include the Gulf Coast of Texas and Louisiana (offshore and onshore), east and west Texas, north Louisiana, Mid-Continent and the Rockies. His international experience includes Canada, South America and Russia. He has an undergraduate degree in Petroleum Engineering from the University of Wyoming (1986) and also holds an MBA, Corporate Finance, from the University of Denver (1988).

Howard E. Ehler has been Vice President and Chief Financial Officer of the Company since the Merger on April 17, 2007. He was employed as Vice President and Chief Financial Officer of AROC, Inc. from May 2001 through December 2004. Since January 2005, Mr. Ehler has been employed by Southern Bay Energy, LLC as Vice President and Chief Financial Officer. He previously served as Vice President of Finance and Chief Financial Officer for Midland Resources, Inc. from March 1997 through October 1998. From November 1999 through April 2001 he performed independent accounting and auditing services in oil and gas as a sole practitioner in public accounting. He was employed in public accounting with various firms for over 21 years, including practice with Grant Thornton, where he was admitted to the partnership. He has substantive experience in oil and gas banking, finance, accounting and reporting. In addition, his experience includes partnership administration, tax, budgets and forecasts and cash management. Mr. Ehler holds an Accounting Degree from Texas Tech University (1966) and has been a certified public accountant since 1970.

PART II

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

Our common stock trades on the NASDAQ Global Market under the Symbol "GEOI." The following tables set forth for the period indicated the low and high trade prices for our common stock as reported by the NASDAQ Global Capital Market. These trade prices may represent prices between dealers and do not include retail markup, markdowns or commissions.

	High	Low
2009		
Fourth Quarter	$ 13.85	$ 10.09
Third Quarter	$ 11.50	$ 8.75
Second Quarter	$ 10.75	$ 6.44
First Quarter	$ 9.74	$ 4.97
2008		
Fourth Quarter	$ 15.29	$ 5.61
Third Quarter	$ 20.74	$ 9.62
Second Quarter	$ 29.08	$ 14.51
First Quarter	$ 15.35	$ 8.00

As of March 11, 2010, there were approximately 500 holders of record of our common stock. We believe that there are also approximately 3,000 additional beneficial owners of our common stock held in "street name."

Dividend Policy

Amounts shown in our historical financial statements as stockholder distributions in 2007 are comprised of distributions by Southern Bay to its partners.

We have never paid dividends on our common stock and do not intend to pay a dividend in the foreseeable future. Furthermore, our amended credit agreement with our bank restricts the payment of cash dividends. The payment of future cash dividends on common stock, if any, will be reviewed periodically by our Board of Directors and will depend upon, among other things, our financial condition, funds available for operations, the amount of anticipated capital and other expenditures, our future business prospects and any restrictions imposed by our present or future bank credit arrangements.

Equity Compensation Plan Information

The following sets forth information as of March 11, 2010, concerning our compensation plan under which shares of our common stock are authorized for issuance.

PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	WEIGHTED AVERAGE EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	NUMBER OF SECURITIES REMAINING AVAILABLE FOR FUTURE ISSUANCE
Equity compensation plans approved by security holders:			
Amended and Restated 2004 Employees' Stock Incentive Plan	2,000,000	$ 9.32	435,000
Equity compensation plans not approved by security holders:	N/A	N/A	N/A

There were not any employee options exercised during 2007, 2008 or 2009.

Item 6. **Selected Financial Data**

	Year ended December 31				
	2009	**2008**	**2007**	**2006**	**2005**
A. Summary of Operating Data					
Production					
Oil (Mbls)	851	743	392	184	154
Natural gas (MMcf)	4,944	2,962	1,648	577	559
Barrel of oil equivalent (MBOE)	1,675	1,236	667	280	247
Average realized prices:					
Oil (per bbl)	$ 61.09	$ 82.42	$ 67.20	$ 54.61	$ 47.97
Natural gas (per Mcf)	$ 3.97	$ 8.12	$ 6.19	$ 6.83	$ 6.86
B. Summary of Operations (in thousands, except per share amounts):					
Oil and gas revenues	$ 71,618	$ 85,263	$ 36,518	$ 13,978	$ 11,221
Total revenues	80,428	94,606	40,115	16,805	13,551
Lease operation and workover expenses	21,570	26,432	12,910	4,636	3,270
Severance taxes	3,623	7,517	2,880	1,066	1,085
Depletion and depreciation	22,409	16,007	7,507	3,382	1,575
Pretax earnings	14,842	21,291	7,949	4,280	4,990
Income tax expense (1)	5,067	7,769	4,880	33	-
Net income	9,775	13,522	3,069	4,247	4,990
Net income per share:					
Basic	$ 0.59	$ 0.87	$ 0.25	$ 0.87	$ 1.21
Diluted	$ 0.59	$ 0.86	$ 0.25	$ 0.87	$ 1.21
C. Summary Balance Sheet Data at Year End (in thousands):					
Net property, plant and equipment	$ 248,386	$ 181,580	$ 181,443	$ 31,229	$ 19,798
Total assets	304,297	243,534	240,358	50,667	43,923
Working capital	11,946	11,883	7,371	(1,689)	625
Long-term debt	69,000	40,000	96,000	5,000	100
Stockholders' equity	174,677	140,995	68,032	23,660	17,558
D. Adjusted EBITDAX (in thousands) (2):					
Net Income	$ 9,775	$ 13,522	$ 3,069	$ 4,247	$ 4,990
Interest expense	4,984	4,820	1,916	288	146
Income tax expense (1)	5,067	7,769	4,880	33	-
Depletion and depreciation	22,409	16,007	7,507	3,382	1,575
Impairment expense	2,795	8,339	-	184	-
Exploration expense	1,406	2,592	153	558	-
Hedge ineffectiveness	137	(123)	287	(393)	399
Loss on derivative contracts	162	563	-	-	-
Non-cash compensation expense	1,424	661	553	422	-
	$ 48,159	**$ 54,150**	**$ 18,365**	**$ 8,721**	**$ 7,110**

(1) The 2006 and 2005 consolidated financial statements were those of Southern Bay, which, as a partnership, was generally not subject to federal and state income taxes.

(2) Adjusted EBITDAX is a Non-GAAP measure that differs from the GAAP measure of Net Income. Adjusted EBITDAX is calculated as shown above. Adjusted EBITDAX should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not in accordance with, nor superior to, generally accepted accounting principles, but provides additional information for evaluation of our operating performance.

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

The following discussion should be read in conjunction with the consolidated financial statements and related notes thereto reflected in the index to the consolidated financial statements in this report.

Merger – Change in Management, Control and Business Strategy

As discussed elsewhere in this report, we underwent a substantial change in ownership, management, voting control, assets and business strategy as a result of the acquisition of Southern Bay and Chandler (via the Merger) and a purchase of working interests in a Chandler-operated project, which closed in April 2007. For financial reporting purposes, the Merger was accounted for as a reverse acquisition of GeoResources, Inc. by Southern Bay.

General

We are an independent oil and gas company engaged in the acquisition and development of oil and gas reserves through an active and diversified program which includes purchases of reserves, re-engineering, development, and exploration activities. As further discussed in this report, future growth in assets, earnings, cash flows and share values will be dependent upon our ability to effectively compete for capital and acquire, discover and develop commercial quantities of oil and gas reserves that can be produced at a profit, and assemble an oil and gas reserve base with a market value exceeding its acquisition, development and production costs.

We continue to implement our business strategy to acquire, discover and develop oil and gas reserves and achieve continued growth. Management continues to focus on reducing operating and administrative costs on a per unit basis. In addition, we have attempted to mitigate downward price volatility by the use of commodity price hedging. The current volatile price environment for oil and natural gas is significant, and management cannot predict the prices that will be available during the life of our current business plan. Following is a brief outline of our current plans:

- Acquire oil and gas properties with significant producing reserves and development and exploration potential;
- Solicit industry partners in acquisitions, on a promoted basis, in order to diversify, reduce average cost and generate operating fees;
- Implement re-engineering and development programs within existing fields;
- Pursue exploration projects and increase direct participation in projects over time. Solicit industry partners, on a promoted basis, for internally generated projects;
- Selectively divest assets to upgrade our producing property portfolio and to lower corporate wide "per-unit" operating and administrative costs, and focus on existing fields and new projects with greater development and exploitation potential;
- Continue activities directed toward reducing per-unit operating and general and administrative costs on a long-term sustained basis; and
- Obtain additional capital through the issuance of equity securities and/or through debt financing.

While the impact and success of our corporate plans cannot be predicted with accuracy, our goal is to replace production and further increase our reserve base at an acquisition or finding cost that will yield attractive rates of return.

In addition to our fundamental business strategy, we intend to actively pursue corporate acquisitions and mergers. Management believes that opportunities may become available to acquire corporate entities or otherwise effect business combinations, particularly as a result of the contraction in equity and debt financing markets. We intend to consider any such opportunities which may become available and are beneficial to stockholders. The primary financial considerations in the evaluation of any such potential transactions include, but are not limited to: (1) the ability of small cap oil and gas companies to gain recognition and favor in the public markets; (2) share appreciation potential; (3) shareholder liquidity; and (4) capital formation and cost of capital to effect growth.

Recent Property Acquisitions and Divestitures

During 2009, we continued to expand our acreage positions, drilling inventory and our drilling programs. We also acquired producing and undeveloped properties, principally in the Bakken Shale trend of the Williston Basin, North Dakota and in Giddings field, Texas. A summary of this activity is as follows:

- In January 2009, we sold a producing property located in Louisiana to an unaffiliated party for $1.6 million. We recognized a gain of $1.3 million in conjunction with this sale.

- In May 2009, we acquired producing wells and acreage in the Bakken Shale trend of the Williston Basin through an existing joint venture where we participate as a non-operator. We acquired a 15% interest in approximately 60,000 net acres, and also acquired 15% of varying working interests in 59 producing and productive wells. Our share of producing wells and undeveloped locations added approximately 486,000 BOE of proved reserves and numerous prospective locations. Including subsequent leasehold acquisitions, we now have working interests in the joint venture ranging from 10% to 18% in approximately 106,000 net acres. The acquisition cost was approximately $10.4 million and was funded with borrowings from our senior secured revolving credit facility.

- In May 2009, we acquired certain oil and gas producing properties in Giddings field, Texas from an affiliated limited partnership for which we serve as the general partner. Prior to the acquisition, we had direct working interests in the properties ranging from about 6.5% to 7.8%. We now hold direct working interests in the producing wells ranging from approximately 34% to 37%. The acquired direct working interests totaled an estimated 25 Bcfe of proved reserves, 88% natural gas and 73% developed, with daily production, at the time of the transaction, totaling 10,625 Mcf and 85 Bbls of associated liquids. In addition, we increased our partnership interest from 2% to 30% amounting to an estimated 13.2 Bcfe. We remain the general partner of the partnership and operator of the properties. The acquisition also provided additional development opportunities and exposure to the potential upside associated with the Yegua, Georgetown and Eagle Ford Shale formations. The interests were purchased for a net cash purchase price of $47.7 million. In addition, we acquired rights to certain post closing severance tax refunds which amounted to $2.4 million. We funded the acquisition with borrowings from our senior secured revolving credit facility.

- In August 2009, we received a distribution of proved undeveloped property and unproved acreage in the Giddings field from an affiliated partnership. The property was recorded at an estimated fair market value of $1.6 million.

Results of Operations

Year ended December 31, 2009, compared to the year ended December 31, 2008.

We recorded net income of $9,775,000 and $13,522,000 for the years ended December 31, 2009, and 2008, respectively. The $3,747,000 decrease in net income resulted primarily from the following factors.

Net amounts contributing to increase (decrease) in net income (in 000s):

Oil and gas sales	$	(13,645)
Lease operating expenses		4,151
Production taxes		3,894
Exploration expense		1,186
Re-engineering and workovers		711
Impairment of oil and gas properties		5,544
General & administrative expense (G&A)		(1,332)
Depletion, depreciation and amortization expenses (DD&A)		(6,402)
Net interest income (expense)		(317)
Hedge ineffectiveness		(260)
Gain / (loss) on derivative contracts		401
Gain / (loss) on sale of property		(3,007)
Other income - net		2,627
Income before income taxes		(6,449)
Provision for income taxes		2,702
Net income	$	(3,747)

The following discussion applies to the above changes.

Oil and Natural Gas Sales. Oil and gas revenues decreased $13,645,000, or 16%; however, as shown in the table below, sales volumes increased significantly. Properties acquired from SBE Partners LP in May 2009, increased revenue by $6,524,000 and production by approximately 2,122,000 Mcf of gas and 5,000 barrels of oil during 2009. Properties acquired in the Bakken acquisition May 2009 accounted for revenue of $3,673,000 and production of approximately 59,000 barrels of oil and 13,000 Mcf of gas during 2009. These increases were offset by significant price declines in the average prices received for oil and natural gas. Price and production comparisons are set forth in the following table:

	Percent increase (decrease)	Year Ended December 31,			
		2009		2008	
Gas Production (MMcf)	67%		4,944		2,962
Oil Production (MBbl)	15%		851		743
Barrel of Oil Equivalent (MBOE)	36%		1,675		1,236
Average Price Gas Before Hedge Settlements (per Mcf)	-61%	$	3.28	$	8.36
Average Price Oil Before Hedge Settlements (per Bbl)	-41%	$	56.37	$	94.88
Average Realized Price Gas (per Mcf)	-51%	$	3.97	$	8.12
Average Realized Price Oil (per Bbl)	-26%	$	61.09	$	82.42

Lease Operating Expenses. Lease operating expenses ("LOE") decreased from approximately $22,914,000 for 2008 to $18,763,000 for 2009, a decrease of $4,151,000 or 18%. On a unit-of-production basis, barrel of oil equivalent ("BOE") LOE costs decreased by $7.33 or 40% due primarily to unprecedented demand for oil field services in 2008 which pushed prices for these services to all time highs during 2008, while the prices for these services decreased during 2009. Additionally, we acquired properties in the SBE Partners and Bakken acquisitions with lower per unit operating costs thus further decreasing our lease operating costs on a per unit basis.

Re-engineering and workover. Our re-engineering and workover costs decreased by $711,000, or 20%, from $3,518,000 in 2008 to $2,807,000 in 2009, due to a cost containment strategy during the lower pricing environment of 2009.

Production Taxes. Our severance taxes decreased by $3,894,000 or 52%, due to decreased oil and gas revenues as well as to tax exemptions granted by the state of Texas for certain high cost drilling wells. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We seek to take full advantage of all credits and exemptions allowed in our various jurisdictions. Our production taxes for 2009 and 2008 were 5.6% and 7.9%, respectively, of oil and gas sales before the effects of hedging. These tax exemptions resulted in reduced severance taxes of approximately $1,232,000, with reduced revenues and slightly lower rates on non-exempt wells accounting for the remaining decrease.

Exploration and Impairment Costs. Our exploration costs were $1,406,000 for 2009 and $2,592,000 for 2008. In 2009, we incurred $1,323,000 for geological and geophysical data and incurred dry hole and other costs of $83,000. In 2008, we drilled four gross exploratory dry holes with costs incurred through December 31, 2008 of $1,948,000, wrote-off undeveloped properties with a cost of $483,000 and incurred geological costs of $161,000. We recorded non-cash impairment charges of $2,795,000 and $8,339,000 in 2009 and 2008, respectively due to the write-down of proved properties. The book value of these properties exceeded our estimate of future cash flows.

General and Administrative Expenses – Our G&A costs increased from $7,168,000 in 2008 to $8,500,000 in 2009, an increase of $1,332,000, or 19%. This was due to overall business expansion as well as increases in salaries and other overhead expenses, partially offset by cost reductions resulting from the centralization of certain job functions. The total non-cash charges related to stock-based compensation included in G&A expense for the years ended December 31, 2009 and 2008 were $1,424,000 and $661,000, respectively.

Depreciation, Depletion and Amortization - DD&A increased from $16,007,000 in 2008 to $22,409,000 in 2009, for an increase of $6,402,000, or 40%. This was due to the substantial increase in capitalized cost attributable to acquisitions, as well as to our active drilling program.

Interest Income and Expense - Interest expense increased by $164,000 due to slightly higher average debt levels during 2009 compared to 2008, partially offset by lower interest rates. Our average outstanding debt was $74,189,000 and $67,233,000 during 2009 and 2008, respectively. The effective annual interest rates were 6.7% and 7.2%, for 2009 and 2008, respectively. These rates reflect the effects of interest swap contract settlements, as well as loan fees. Interest income decreased by $153,000 during 2009 compared to 2008 due to lower interest rates on average invested cash balances.

Hedge Ineffectiveness. During 2009, the loss from hedge ineffectiveness was $137,000, compared to a gain of $123,000 for 2008. In 2009, our derivatives that are accounted for as cash flow hedges decreased in value from a net asset to a net liability; therefore, the ineffective portion of these derivatives resulted in a loss. In 2008, our derivatives that were accounted for as cash flow hedges increased in value. Therefore, the ineffective portion of the derivatives resulted in a gain.

Loss on Derivative Contracts. In December, 2008, we split up a $50 million notional value interest rate swap that was previously accounted for as a cash flow hedge. The swap was split up into a $10 million swap and $40 million notional amount swap. We continued hedge accounting for the $40 million swap and accounted for the $10 million swap as a trading security. We recognized losses of $162,000 and $563,000 in 2009 and 2008, respectively, related to this swap.

Other Income. Other income increased by $2,627,000 during 2009 compared to 2008. Partnership income increased by $3,257,000, from $1,061,000 in 2008 to $4,318,000 in 2009. Gains on sales of properties to the general partner accounted for $1,278,000 of this increase and refunds of severance taxes on wells for which the state of Texas granted exemptions accounted for $1,256,000 of the increase. The remaining increase in partnership income resulted from our earning a larger share of partnership income. Additionally, during 2008, we sold a number of non-core properties and recognized a gain of $4,362,000 versus gains of only $1,355,000 in 2009.

Income Tax Expense. Our provision for income taxes for 2009 was $5,067,000 compared to $7,769,000 for 2008. This decrease of $2,702,000 was due to lower pretax income, as well as slightly lower rates. Our effective tax rates for 2009 and 2008 were 34.14% and 36.50%, respectively.

Year ended December 31, 2008, compared to the year ended December 31, 2007.

We recorded net income of $13,522,000 and $3,069,000 for the years ended December 31, 2008, and 2007, respectively. The $10,453,000 increase in net income resulted primarily from the following factors.

Net amounts contributing to increase (decrease) in net income (in 000s):

Oil and gas sales	$ 48,745
Lease operating expenses	(12,096)
Production taxes	(4,637)
Exploration expense	(2,439)
Re-engineering and workovers	(1,426)
Impairment of oil and gas properties	(8,339)
General & administrative expense (G&A)	(655)
Depletion, depreciation and amortization expenses (DD&A)	(8,500)
Net interest income (expense)	(3,283)
Hedge ineffectiveness	410
Gain / (loss) on derivative contracts	(563)
Gain / (loss) on sale of property	4,313
Other income - net	1,812
Income before income taxes	13,342
Provision for income taxes	(2,889)
Net income	$ 10,453

The following discussion applies to the above changes.

Oil and Natural Gas Sales. Net revenues from oil and gas sales increased $48,745,000, or 133%. Properties acquired from AROC Energy LP in October 2007, accounted for approximately $41,182,000 of the increase. The remaining $7,563,000 increase resulted primarily from an increase in commodity prices and increase in production volumes. Price and production comparisons are set forth in the following table. Properties acquired from AROC Energy LP accounted for increased production of approximately 1,063,000 Mcf of gas and approximately 789,000 barrels of oil during 2008.

	Percent increase (decrease)	Year Ended December 31, 2008	Year Ended December 31, 2007
Gas Production (MMcf)	80%	2,962	1,648
Oil Production (MBbl)	90%	743	392
Barrel of Oil Equivalent (MBOE)	85%	1,236	667
Average Price Gas Before Hedge Settlements (per Mcf)	27%	$ 8.36	$ 6.56
Average Price Oil Before Hedge Settlements (per Bbl)	30%	$ 94.88	$ 73.06
Average Realized Price Gas (per Mcf)	31%	$ 8.12	$ 6.19
Average Realized Price Oil (per Bbl)	23%	$ 82.42	$ 67.20

Lease Operating Expenses. Our LOE expenses increased from approximately $10,818,000 for 2007 to $22,914,000 for 2008, an increase of $12,096,000 or 112%. Properties acquired from AROC Energy LP accounted for $9,146,000 of the increase. On a unit-of-production basis, LOE per BOE increased by $2.32 or 14% as a result of higher costs due to unprecedented demand for personnel, materials, services and rigs caused by high commodity prices during most of 2008.

Re-engineering and workover. Our re-engineering and workover costs increased by $1,426,000 from $2,092,000 in 2007 to $3,518,000 in 2008, due to an increased emphasis on restoring and enhancing existing production capabilities.

Production Taxes. Our production taxes increased by $4,637,000 or 161%, due to increased production volumes and revenues. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various jurisdictions. Our production taxes for 2008 and 2007 were 7.9% and 7.3%, respectively, of oil and gas sales before the effects of hedging. The 2008 rate increased slightly from 2007 mainly due to change in our portfolio of producing properties.

Exploration and Impairment Costs. Our exploration costs were $2,592,000 for 2008, and $153,000 for 2007. In 2008, we drilled four gross exploratory dry holes with costs incurred through December 31, 2008, of $1,948,000, wrote-off undeveloped properties with a cost of $483,000 and incurred geological costs of $161,000. In 2007, we incurred $153,000 for geological and geophysical data. In 2008, we recorded a non-cash impairment charge of $8,339,000 due to the write-down of proved properties. The book value of these properties exceeded our estimate of future cash flows. We had no impairments in 2007.

General and Administrative Expenses – Our G&A costs increased $655,000 due primarily to overall business expansion as well as increases in salaries and other overhead expenses, partially offset by cost reductions resulting from the centralization of certain job functions.

Depreciation, Depletion and Amortization - The increase in DD&A expenses attributable to the properties acquired from AROC Energy LP was $5,618,000. The remaining increase of $2,882,000 was due to higher DD&A in the fourth quarter of 2008 due to lower reserve estimates at year-end, which was caused by lower commodity prices.

Interest Income and Expense - Interest expense increased by $2,904,000 due to higher average debt levels during 2008, compared to 2007. During the first ten months of 2007, we had a long-term debt balance of less than $10 million. In October, 2007, we borrowed $96 million in conjunction with the AROC Energy LP acquisition. During 2008, we paid down this balance to $40 million. Interest income decreased by $379,000 during 2008, compared to 2007, due to lower interest rates on average invested cash balances.

Hedge Ineffectiveness. During 2008, the gain from hedge ineffectiveness was $123,000, compared to an expense of $287,000 for 2007. In 2008, our derivatives that we accounted for as cash flow hedges increased in value from a net liability to a net asset; therefore, the ineffective portion of these derivatives resulted in a gain on our income statement. In 2007, our derivatives that were accounted for as cash flow hedges decreased in value. Therefore, the ineffective portion of the derivatives resulted in a loss on our income statement.

Loss on Derivative Contracts. In December, 2008, we split up a $50 million notional value interest rate swap that was previously accounted for as a cash flow hedge. The swap was split up into a $10 million swap and $40 million notional amount swap. We continued hedge accounting for the $40 million swap and accounted for the $10 million swap as a trading security. We recognized $563,000 of losses related to this $10 million interest rate swap.

Other Income. Other income increased by $1,812,000 during 2008, compared to 2007. The increase resulted from increases in partnership management fees of $756,000, increases in partnership income of $877,000 and increases in property operating income of $179,000. Additionally, during 2008, we sold a number of non-core properties and recognized a gain of $4,362,000 versus gains of only $49,000 in 2007.

Income Tax Expense. Our provision for income taxes for 2008 was $7,769,000 compared to $4,880,000 for 2007. Our income tax expense increased significantly as a result of higher pre-tax earnings. Our effective tax rate for 2008 was approximately 36.5%. Our effective tax rate for 2007, after excluding a non-recurring charge of $2,214,000, was approximately 34%. Deferred income tax expense for 2007 included a non-recurring charge of $2,214,000. GAAP requires that when an entity's tax status changes from non-taxable to taxable, the deferred taxes related to differences in the GAAP basis of net assets and their tax basis, be recognized in the period of that change in status. The increase in our effective tax rate from year to year was due to a 1% increase in our federal rate as well as the additional income from our Northern Region which was taxable at the state level.

Hedging Activities

In an attempt to reduce our sensitivity to oil and gas price volatility and secure favorable debt financing, we have and will likely continue to enter into hedging transactions which may include fixed price swaps, price collars, puts and other derivatives. We believe our hedging strategy should result in greater predictability of internally generated funds, which in turn can be dedicated to capital development projects and corporate obligations. The following is a summary of our current oil and gas hedge contracts.

	Total Annual Volume	Floor Price	Ceiling / Swap Price
Crude Oil Contracts (Bbls):			
Swap contracts:			
2010	322,000		$ 74.710
2010 (added Jan. 8, 2010)	110,000		$ 85.320
2011	282,000		$ 74.730
2011 (added Jan. 8, 2010)	84,000		$ 88.450
Forward sales contracts:			
2010	27,000		$ 43.850
Natural Gas Contracts (Mmbtu)			
Swap contracts:			
2010	150,000		$ 4.860
2010	150,000		$ 4.870
2010	1,440,000		$ 5.155
2010	480,000		$ 5.195
2010	360,000		$ 6.065
2011	210,000		$ 6.065
2011	630,000		$ 6.450
2012	150,000		$ 6.450
2012	450,000		$ 6.415
Costless collars contracts:			
2010	1,287,000	$ 7.00	$ 9.900
2011	1,079,000	$ 7.00	$ 9.200

The fair market value of our gas hedge contracts in place at December 31, 2009, was an asset of $2,124,000, of which $764,000 was classified as a current asset. The fair market value of our oil hedge contracts was a liability of $6,400,000 of which $3,167,000 was classified as a current liability. The fair market value of all our commodity hedge contracts in place at December 31, 2008, was an asset of $14,609,000 of which $8,200,000 was classified as a current asset. For the year ended December 31, 2009, we recognized, in oil and gas revenues, realized cash settlement gains on commodity derivatives of $7,434,000. Realized hedge settlements losses included in oil and gas revenues were $9,970,000 and $2,910,000 for 2008 and 2007, respectively. Due to hedge ineffectiveness on these hedge contracts during 2009 we recognized a loss of $137,000. During 2008 and 2007, we recognized a gain due to hedge ineffectiveness of $123,000 and a loss of $287,000, respectively.

Based on the estimated fair market value of our derivatives, designated as hedges at December 31, 2009, we expect to reclassify net losses on commodity derivatives of $2.4 million into earnings from accumulated other comprehensive income during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially.

At December 31, 2009, a 10% increase in per unit commodity prices would cause the total fair value liability of our commodity derivative financial instruments to increase by $9 to $10 million. A 10% decrease in per unit commodity prices would cause the fair value liability to change to an asset due to an estimated $9 to $10 million decrease in the net liability. There would also be a similar increase or decrease in other comprehensive income (loss) included in stockholders' equity in the balance sheet. Since we have designated all of our commodity derivative instruments as cash flow hedges and therefore the change in market value of the effective portion of the hedge is included in other comprehensive income, a 10% change in fair value would not have a significant effect on net income. However, if our hedges did not qualify for hedge accounting treatment, our net income for 2009 would have decreased by $10.8 million.

Additionally, should commodity prices increase or decrease in the future periods by 10%, our realized settlement gains (losses) on commodity derivatives, which are included in oil and gas revenues, would increase or decrease by approximately $5 to $6 million in 2010.

In connection with the borrowing from our bank to fund the October, 2007, AROC acquisition, we also entered into a two-year interest rate swap contract on $50 million of the debt, designed to protect us against interest rate increases. During 2008, we extended the term of this interest rate swap through October, 2010, and broke the swap up into two pieces, a $40 million swap and a $10 million swap. We account for the $40 million swap as a cash flow hedge while the $10 million swap is accounted for as a trading security. The value of these swaps at December 31, 2009 was a liability of $1,627,000 all of which is classified as a current liability. The value of these swaps at December 31, 2008, was $2,817,000 of which $1,572,000 is classified as a current liability. We also recognized losses of $162,000 and $563,000 during 2009 and 2008, respectively, on the $10 million swap.

Based on the estimated fair market value of our derivatives designated as hedges at December 31, 2009, we expect to reclassify net losses on our $40 million interest rate swap derivative of $1.3 million into earnings from accumulated other comprehensive income during the next twelve months; however, actual cash settlements may differ materially.

We do not engage in speculative commodity trading activities and do not hedge all available or anticipated quantities of our production. In implementing our hedging strategy we seek to:

- Effectively manage cash flow to minimize price volatility and generate internal funds available for capital development projects and additional acquisitions;
- Ensure our ability to support our exploration activities as well as administrative and debt service obligation; and
- Allow certain quantities to float, particularly in months with historically increased price potential.

We believe that commodity speculation and commodity trading activities are inappropriate for us, but also that management of realized prices is a necessary part of our strategy.

Estimating the fair value of derivative instruments requires complex calculations, including the use of a discounted cash flow technique, estimates of risk and volatility, and subjective judgment in selecting an appropriate discount rate. In addition, the calculations use future market commodity prices which, although posted for trading purposes, are merely the market consensus of forecasted price trends. The results of the fair value calculation cannot be expected to represent exactly the fair value of our commodity hedges. We currently obtain fair value positions from our counterparties and compare that value to our internally calculated value. We believe that our practice of comparing our value to that of our counterparties, who are more specialized and knowledgeable in preparing these complex calculations, reduces our risk of error and approximates the fair value of the contracts, as the fair value obtained from our counterparties would be the cost to us to terminate a contract at that point in time.

Administrative and Operating Costs

On an ongoing basis, we focus on cost-containment efforts related to administrative and operating costs. However, we must continue to attract and retain competent management, technical and administrative personnel to successfully pursue our business strategy and fulfill our contractual obligations.

Liquidity and Capital Resources

We expect to finance future acquisition, development and exploration activities through working capital, cash flows from operating activities, our bank credit facility, sale of non-strategic assets, various means of corporate and project finance and possibly through issuance of additional securities. In addition, we intend to continue to partially finance our drilling activities through the sale of participations to industry or institutional partners on a promoted basis, whereby we may earn working interests in reserves and production greater than our proportionate capital costs. Financing activities during 2009 resulted in a net increase in debt of $29 million from the outstanding debt of $40 million at December 31, 2008. During the second quarter of 2009, we borrowed an additional $64 million to fund the SBE Partners and Bakken acquisitions discussed above. During the fourth quarter of 2009, we completed a public offering of common stock and repaid $35 million in debt using the $33 million net proceeds from the stock issue plus $2 million in cash flows from operations.

	December 31,					
	2009		2008		2007	
			(Millions)			
Balances outstanding, beginning of year	$	40.0	$	96.0	$	5.0
Borrowings		64.0		-		99.0
Assumption of debt in Merger		-		-		1.8
Repayments of debt		(35.0)		(56.0)		(9.8)
Balances outstanding, end of year	$	69.0	$	40.0	$	96.0
Issuance of common stock	$	33.1	$	32.2	$	23.5
Distributions to stockholders (1)	$	-	$	-	$	(4.0)

(1) The amount shown as stockholder distributions in 2007 are comprised of distributions by Southern Bay to its partners prior to the Merger.

Credit Facility

At December 31, 2009, we had a $145 million borrowing base, with available borrowing capacity of $76 million in accordance with our Amended Credit Agreement with our bank. The borrowing base is redetermined in May and November of each year.

Cash Flows From Operating Activities

For 2009, net cash provided by operating activities was $24.0 million, down $18.3 million from 2008. This decrease was directly attributable to the decrease in commodity prices, partially offset by decreases in lease operating expenses, re-engineering and workover expenses and other cost control measures.

Cash Flows From Investing Activities

Cash applied to oil and gas capital expenditures was $89.4 million for 2009, $51.8 million for 2008, and $110.1 million for 2007. In 2009 and 2008, we realized cash of $2 million and $26.8 million, respectively, from the sale of non-core properties. In 2007, we collected $2.4 million from the sale of non-core properties. During 2009, we completed two acquisitions for a combined cost of $56.7 million. During 2008, we invested $978,000 in newly formed oil and gas limited partnership for which we are the general partner. In 2007, we invested $1.6 million in different oil and gas limited partnership for which we are also the general partner.

Capital Budget

We continue to expand our portfolio of drilling and development projects and therefore have recently increased our projected drilling and development expenditures. As of December 31, 2009, we have identified approximately $160 million of diversified exploration and development projects, which are summarized in the table below. From this list of identified projects, we currently have budgeted capital expenditures of $90 to $100 million for 2010 and 2011. While the table includes the bulk of our currently identified projects, we are constantly working on developing and acquiring new opportunities. In addition, seismic and acreage expenditures as well as drilling results will likely lead to modifications of our estimates. A benefit of our portfolio is that it includes both gas and oil opportunities, much of which are "held by production" and therefore not subject to lease expiration or significant future incremental carrying costs. Accordingly, we have some ability to adjust our capital spending as our financial position and industry circumstances dictate. Generally, we are committed to limiting our capital spending to our cash flow, although in certain limited circumstances, we may utilize our borrowing capacity for development or lease saving operations. We do not intend to use our borrowing capacity for exploratory drilling. We may, however, shift our expenditures between geographic areas and projects (such as development versus exploration) in an attempt to maximize cash flow and take advantage of regional differences in net commodity prices and service costs. Furthermore, our budget may be accelerated or deferred, pending commodity prices, drilling and service rig availability and cost, and adequate staffing to effectively manage activities and control costs. While financial conditions and industry circumstances may require us to make adjustments, it is our current intent to continue our Bakken and Austin Chalk drilling programs and certain other projects in the Gulf Coast, West Texas and the Williston Basin.

Generally, management undertakes a complete budget review in the Spring of each year, but modifies the budget and actual expenditures throughout the year as deemed appropriate. The projects, estimated costs and timing of actual expenditures are subject to significant change as we continue to technically and economically evaluate existing and alternative projects, as we further expand our portfolio, and as industry conditions dictate. Estimated expenditures are also subject to significant change. There can be no assurance that all of the projects identified and summarized in the table below will remain viable and therefore certain projects may be sold or abandoned by us. However, in the opinion of management, at present, we have sufficient cash flows and liquidity to fulfill lease obligations or otherwise maintain all material mineral leases.

	($ in Millions)	Percent of District Opportunity
Southern District		
Austin Chalk drilling and development [1] [2]	$ 50.9	59%
Other development drilling [2]	17.6	20%
Exploratory drilling [3]	7.7	9%
Acreage, seismic and other [5]	7.0	8%
Re-engineering [4]	2.5	3%
Waterflood expansion [2]	1.0	1%
	86.7	
Northern District		
Bakken Shale drilling [6] [2]	$ 39.5	54%
Other development drilling [2]	22.6	31%
Acreage, seismic and other [5]	7.0	10%
Waterflood and associated drilling [2]	3.2	4%
Re-engineering [4]	1.0	1%
	73.3	
Total	**$ 160.0**	

Notes:

(1) Horizontal drilling and development program with an affiliated institutional partnership. As of December 31, 2009, we identified 22 additional drilling locations, many of which are expected to be dual lateral wells. We also expect to re-enter certain well bores and extend existing laterals or drill additional laterals, none of the possible re-entries are included in the above table as all such opportunities are held by production and have no critical timing.

(2) Includes both proved undeveloped and non-proved reserve potential.

(3) Principally south Louisiana and the Texas Gulf Coast.

(4) Includes activities related to existing fields intended to enhance production and lower operating expenses. These expenditures include replacement, repairs or additional flow lines, facilities, and/or compression as well as the modification of the down-hole lift method and re-completions.

(5) Potential expenditures associated with further expansion of acreage and prospect inventory generally within close proximity of our existing fields.

(6) The estimates included above relate to both our operated and non-operated positions in the Bakken Shale play of the Williston Basin. This is one of our core areas and the Bakken trend is experiencing rapid expansion and development. Pursuant to our business strategy, as in other geographic areas, we have expanded our acreage positions and increased our working interests. The estimated expenditures included above are based on actual and anticipated contractual commitments and the current advice of other operators, where such information is available. The nature of this play and its rapid expansion make estimates particularly difficult to determine with reasonable certainty and therefore this estimate is subject to material change.

New Accounting Standards

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, *Improving Disclosures about Fair Value Measurements* ("ASU 2010-06"), which provides amendments to FASB ASC topic *Fair Value Measurements and Disclosures* that will provide more robust disclosures about (i) the different classes of assets and liabilities measured at fair value, (ii) the valuation techniques used, (iii) the activity in Level 3 fair value measurements, and (iv) the transfers between Level 1, 2 and 3. ASU 2010-06 is effective for fiscal years and interim periods beginning after December 15, 2009. We are currently assessing the impact that the adoption will have on its disclosures.

For further information on the effects of recently adopted accounting pronouncements, refer to Recently Issued Accounting Pronouncements in the Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note A to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Oil and Gas Properties

We use the successful efforts method of accounting for oil and gas operations. Under this method, costs to acquire oil and gas properties, drill successful exploratory wells, drill and equip development wells, and install production facilities are capitalized. Exploration costs, including unsuccessful exploratory wells, geological, geophysical as well as cost of carrying and retaining unproved properties are charged to operations as incurred. Depreciation, depletion and amortization ("DD&A") of the capitalized costs associated with proved oil and gas properties are computed using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum engineers. Oil and gas properties are periodically assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. Long-lived assets committed by management for disposal are accounted for at the lower of cost or fair value, less cost to sell. All of our properties are located within the continental United States and the Gulf of Mexico.

Oil and Natural Gas Reserve Quantities

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties, and asset retirement obligations. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of our reserve estimates is a function of:

- The quality and quantity of available data;
- The interpretation of that data;
- The accuracy of various mandated economic assumptions; and
- The judgments of the persons preparing the estimates.

Our proved reserves information included in this report is based on estimates prepared by our independent petroleum engineers, Cawley, Gillespie & Associates, Inc. The independent petroleum engineers evaluated 100% of our estimated proved reserve quantities and their related future net cash flows as of December 31, 2009. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. We make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates, impairment calculations, and asset retirement obligations in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization ("DD&A")

Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties

We review the value of our oil and gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments of producing properties are determined by comparing the pretax future net undiscounted cash flows to the net book value at the end of each period. If the net capitalized cost exceeds undiscounted future cash flows, the cost of the property is written down to "fair value," which is determined based on expected future cash flows using discounted rates commensurate with the risks involved, using prices and costs consistent with those used for internal decision making. Different pricing assumptions or discount rates could result in a different calculated impairment. We provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred.

Asset Retirement Obligation

Our asset retirement obligations ("AROs") consist primarily of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas field.

Derivative Instruments and Hedging Activity

We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We use hedging to help ensure that we have adequate cash flows to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based, in part, on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. We primarily utilize swaps and costless collars, which are placed with major financial institutions. The oil and natural gas reference prices of these commodity derivative contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices we receive. All derivative instruments are recorded on the consolidated balance sheet at fair value. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the fair value gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective and is reclassified to gain (loss) on oil and natural gas hedging activities line item in our consolidated statements of income in the period that the hedged production is delivered. Hedge effectiveness is measured quarterly based on the relative changes in the fair value between the derivative contract and the hedged item over time.

Our costless collars are valued based on the counterparty's marked-to-market statements, which are validated by observable transactions for the same or similar commodity options using the NYMEX futures index. Our swaps are valued based on a discounted future cash flow model. Our primary input for the model is the NYMEX futures index. Our model is validated by the counterparty's marked-to-market statements. The discount rate used in determining the fair values of these instruments includes a measure of nonperformance risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Our results of operations each period can be impacted by our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control. If our derivative contracts would not qualify for cash flow hedge treatment, then our consolidated statements of income could include large non-cash fluctuations, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

Income Taxes and Uncertain Tax Positions

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

We will consider a tax position settled if the taxing authority has completed its examination, we do not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. We use the benefit recognition model which contains a two-step approach, a more likely than not recognition criteria and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, then we will not record the tax benefit. The amount of interest expense that we recognize related to uncertain tax positions is computed by applying the applicable statutory rate of interest to the difference between the tax position recognized and the amount previously taken or expected to be taken in a tax return.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition

We predominantly derive our revenue from the sale of produced oil and gas. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. Historically, however, differences have been insignificant.

Accounting for Business Combinations

Our business has grown substantially through acquisitions, and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations to date using the purchase method.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets, liabilities and non-controlling interests acquired are measured at their fair value including the recognition of acquisition-related costs and anticipated restructuring costs that are separate from the acquired net assets. The purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets. Certain contingent assets acquired and liabilities assumed in a business combination are recognized at fair value on the acquisition date if we can reasonably estimate a fair value during the measurement period.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities, and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Effects of Inflation and Pricing

We experienced increased costs during 2008 and 2007 due to increased demand for oil field products and services. In 2009, these all time high prices for services decreased somewhat. The oil and gas industry is cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put significant pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Impact of Regulation of Greenhouse Gas Emissions

The operations of and use of the products produced by the natural gas and oil industry are sources of emissions of certain greenhouse gases ("GHG's"), namely carbon dioxide and methane. Regulation of GHG emissions has not had an impact on our operations in the past, and the regulation of our GHG emissions as such has not occurred. However, there is a trend towards government-imposed limitation of GHG emissions at the state, regional, and federal level.

The United States Environmental Protection Agency ("EPA"), by virtue of a recent Supreme Court decision, was deemed to have authority to regulate carbon dioxide and other GHG emissions under the Clean Air Act, and they are drafting and preparing to implement regulations. It is possible that legislation will be proposed to amend the Clean Air Act to exclude GHG's, but we believe the probability of the enactment of such legislation is uncertain.

In addition, in 2009 there was a significant effort in the United States Congress to enact legislation to establish a cap-and-trade system as a means to regulate GHG emissions. A cap-and-trade bill was approved by the House of Representatives, but it appears uncertain that similar legislation will pass in the Senate. Therefore, it appears that the probability of enactment of a cap-and-trade bill in 2010 may be relatively low at this time, but is fairly unpredictable. Because of the uncertainty of the nature of any potential future federal GHG regulations at this time, we are unable to forecast how future regulation of GHG emissions would negatively impact our operations. We will continue to monitor regulatory developments and to assess our ability to reasonably predict the economic impact of these developments on our business.

The commercial risk associated with the exploration and production of fossil fuels lies in the uncertainty of government-imposed climate change legislation, including cap-and-trade schemes, and regulations that may affect our customers, which could affect the demand for crude oil and natural gas. Such an impact on demand could have an adverse impact on the demand for our services, and could have an impact on our financial condition, results of operations and cash flows.

On the other hand, natural gas produces less greenhouse gas emissions when burned than other fossil fuels, such as refined petroleum products or coal. As a result, climate change legislation could create an increased demand for natural gas.

To what extent climate change may result in an increase in extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow and ice storms, as well as rising sea levels is uncertain. Extreme weather conditions could increase our costs and damages resulting from extreme weather, for which we may not be fully insured. However, to what extent climate change may lead to increased storm or weather hazards or affect our operations, is difficult to determine at this time.

Off Balance Sheet Arrangements

We have no off balance sheet arrangements, special purpose entities, financing partnerships or guarantees.

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

We are exposed to market risk from changes in commodity prices. In the normal course of business, we enter into derivative transactions, including commodity price collars, swaps and floors to mitigate our exposure to commodity price movements. We do not participate in these transactions for trading or speculative purposes. While the use of these arrangements limits the benefit to us of increases in the price of oil and natural gas, it also limits the downside risk of adverse price movements.

The following is a list of contracts outstanding at December 31, 2009:

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Remaining Annual Volumes	Fair Value Outstanding as of December 31, 2009 (in thousands)
Natural Gas						
October-07	Collar	01/01/10	12/31/10	$7.00 - $9.90	1,287,000 Mmbtu	$ 1,679
October-07	Collar	01/01/11	12/31/11	$7.00 - $9.20	1,079,000 Mmbtu	1,407
February-09	Swap	01/01/10	03/31/10	$4.860	150,000 Mmbtu	(117)
March-09	Swap	01/01/10	03/31/10	$4.870	150,000 Mmbtu	(115)
June-09	Swap	01/01/01	12/31/10	$5.155	1,440,000 Mmbtu	(770)
June-09	Swap	01/01/10	12/31/10	$5.195	480,000 Mmbtu	(238)
December-09	Swap	04/01/10	03/31/11	$6.065	570,000 Mmbtu	27
December-09	Swap	04/01/11	03/31/12	$6.450	780,000 Mmbtu	178
December-09	Swap	04/01/12	12/31/12	$6.415	450,000 Mmbtu	72
						2,123
Crude Oil						
October-07	Swap	01/01/10	12/31/10	$74.71	322,000 Bbls	(2,381)
October-07	Swap	01/01/11	12/31/11	$74.37	282,000 Bbls	(3,233)
March-09	Forward Sale	04/01/09	03/31/10	$43.85	27,000 Bbls	(785)
						(6,399)
Interest Rate						
Oct-07/Dec-09	Swap	10/10/07	10/16/10	4.29375%	$40 Million Notional 30-day LIBOR	(1,302)
Oct-07/Dec-09	Swap	12/16/08	10/16/10	4.29375%	$10 Million Notional 30-day LIBOR	(325)
						(1,627)
						$ (5,903)

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

See "Index to Consolidated Financial Statements and Supplementary Information" of Page F-1.

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

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our Chief Executive Officer, Chief Financial Officer and other members of management evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of December 31, 2009. Based upon their evaluation of these disclosure controls and procedures, the Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of December 31, 2009, in ensuring that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive and principal financial officers to allow timely discussion regarding required disclosure.

(b) Management's Report on Internal Control over Financial Reporting

The management of GeoResources, Inc. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements of external purposes is accordance with generally accepted accounting principles.

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009 using criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management believes that, as of December 31, 2009, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report which included herein on the following page.

(c) Attestation Report of Registered Public Accounting Firm

Board of Directors and Shareholders of GeoResources, Inc.:

We have audited GeoResources Inc.'s (a Colorado Corporation) and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). GeoResources, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on GeoResources, Inc. and subsidiaries' internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider 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 and procedures may deteriorate.

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of GeoResources, Inc. and subsidiaries as of December 31, 2009 and 2008 and the related consolidated statements of income, stockholders' equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2009, and our report dated March 12, 2010, expressed an unqualified opinion on those consolidated financial statements.

/s/ Grant Thornton LLP
Houston, Texas
March 12, 2010

(d) Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2009, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is included in our definitive proxy material under the heading "Election of Directors" and "Board of Directors" to be filed with the SEC within 120 days after December 31, 2009.

Item 11. Executive Compensation

The information required by this items is included in our definitive proxy material under the heading "Executive Compensation and Other Transactions" to be filed with the SEC within 120 days after December 31, 2009.

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

The information required by this items is included in our definitive proxy material under the heading "Security Ownership of Certain Beneficial Owners and Management Related Stockholder Matters" to be filed with the SEC within 120 days after December 31, 2009.

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by this items is included in our definitive proxy material under the heading "Certain Relationships and Related Transaction and Director Independence" to be filed with the SEC within 120 days after December 31, 2009.

Item 14. Principal Accountant Fees and Services

The information required by this items is included in our definitive proxy material under the heading "Independent Public Accountants" to be filed with the SEC within 120 days after December 31, 2009.

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

EXHIBIT INDEX

FOR

Form 10-K for the year ended December 31, 2009.

3.1	Amended and Restated Articles of Incorporation dates June 10, 2003, incorporated by reference to Exhibit 3.1 of Registrant's Form 10-KSB for the year ended December 31, 2003.
3.1(a)	Articles of Amendment to the Articles of Incorporation, incorporated by reference as Annex C to the Registrant's definitive Proxy Statement dated February 23, 2007, and filed with the Commission on February 23, 2007.
3.1(b)	Articles of Amendment to Articles of Incorporation, dated November 6, 2007. (5)
3.2	Bylaws, as amended March 2, 2004, incorporated by reference to Exhibit 3.2 of Registrant's Form 10-KSB for the year ended December 31, 2003.
10.15	Agreement and Plan of Merger dated September 14, 2006, among GeoResources, Inc., Southern Bay Energy Acquisition, LLC, Chandler Acquisition, LLC, Southern Bay Oil & Gas, L.P., Chandler Energy, LLC and PICA Energy, LLC (including Amendment No. 1 dated February 16, 2007). Incorporated by reference as Annex A to the Registrant's Definitive Proxy Statement dated February 23, 2007 and filed with the Commission on February 23, 2007.
10.19	June 7, 2001 Lease Agreement by and between AROC, Inc. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090. (3)
10.20	First Amendment to June 7, 2001 Lease Agreement by and between AROC, Inc. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated November 10, 2003. (3)
10.21	Assignment and Assumption by Southern Bay Energy, L.L.C. of June 7, 2001 Lease Agreement by and between AROC, Inc. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 19, 2005. (3)
10.22	Unconditional Guaranty of June 7, 2001 Lease Agreement by and between Southern Bay Energy, L.L.C. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 19, 2005. (3)
10.23	Second Amendment to June 7, 2001 Lease Agreement by and between Southern Bay Energy, L.L.C. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 19, 2005. (3)
10.24	Third Amendment to June 7, 2001 Lease Agreement by and between Southern Bay Energy, L.L.C. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 9, 2007. (3)
10.26	January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street Building, Suite 860, 475 17th Street, Denver, Colorado 80202. (3)
10.27	First Amendment to January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street, Suite 860, Denver, Colorado 80202, dated September 28, 2001. (3)
10.28	Second Amendment to January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street, Suite 860, Denver, Colorado 80202, dated October 23, 2002. (3)
10.29	Third Amendment to January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street, Suite 860, Denver, Colorado 80202, dated June 28, 2004. (3)
10.30	Credit Agreement dated September 26, 2007 between the Registrant and Wachovia Bank National Association. (2)

10.31	Limited Partner Interest Purchase and Sale Agreement dated October 16, 2007 between the Registrant and TIFD III-X, LLC (2)
10.32	Amended and Restated Credit Agreement dated October 16, 2007 between the Registrant and Wachovia Bank National Association (2)
10.33	Amended and Restated Credit Agreement dated October 16, 2007 between the Registrant and Wachovia Bank National Association (2)
10.34	Form of Purchase Agreement (4)
10.35	Form of Warrant (4)
10.36	Form of Registration Rights Agreement (4)
10.37	Agreement of Limited Partnership for OKLA Energy Partners LP dated May 20, 2008 (6)
10.38	Lease Agreement by and between Southern Bay Energy, L.L.C. and Cypress Court Operating Associates, L.P. for office space at 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated September 25, 2008. (7)
10.39	Purchase and Sale Agreement between SBE Partners LP and Catena Oil and Gas LLC, dated May 29, 2009. (8)
10.40	Consent and Amendment No. 1 to Agreement of Limited Partnership of SBE Partners LP as of May 29, 2009. (8)
10.41	Second Amended and Restated Credit Agreement between the Registrant and Wachovia Bank, National Association as Administrative Agent dated July 13, 2009. (8)
10.42	Consent, Distribution Agreement, and Amendment No. 2 to Agreement of Limited Partnership of SBE Partners LP (9)
10.43	First Amendment to Lease Agreement by and between Southern Bay Energy, L.L.C. and Cypress Court Operating Associates, Limited Partnership for office space at 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated January 29, 2010. (1)
14.1	Code of Business Conduct and Ethics adopted March 2, 2004, incorporated by reference to Exhibit 14.1 of Registrant's Form 10-KSB for fiscal year ended December 31, 2003.
21.1	Subsidiaries of the Registrant. (3)
23.1	Consent of Grant Thornton LLP (for GeoResources). (1)
23.2	Consent of Grant Thornton LLP (for SBE Partners LP). (1)
23.3	Consent of Cawley, Gillespie & Associates, Inc. (1)
24.1	Power of Attorney (5)
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act. (1)
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act. (1)
32.1	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act. (1)
32.2	Certification of the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act. (1)
99.1	Financial Statements and Report of Independent Certified Public Accountants for SBE Partners LP for the years ended December 31, 2009, 2008 and 2007 (1)
99.2	Report of Cawley, Gillespie & Associates, Inc. dated February 22, 2010 (1)

(1) Filed herewith.
(2) Filed with the Registrant's Form 10-QSB for the quarter ended September 30, 2007.
(3) Filed with the Registrant's Form 10-QSB for the quarter ended June 30, 2007.

(4) Filed with the Registrant's Form 8-K on June 11, 2008.
(5) Filed with the Registrant's Form 10-KSB for the year ended December 31, 2007.
(6) Filed with the Registrant's Form 10-Q for the quarter ended June 30, 2008.
(7) Filed with the Registrant's Form 10-Q for the quarter ended September 30, 2008.
(8) Filed with the Registrant's Form 10-Q for the quarter ended June 30, 2009.
(9) Filed with the Registrant's Form 10-Q for the quarter ended September 30, 2009.

GEORESOURCES, INC. and SUBSIDARIES

Index to Consolidated Financial Statements and Supplementary Information

CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of GeoResources, Inc.:

We have audited the accompanying consolidated balance sheets of GeoResources, Inc. (a Colorado corporation) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements in income, stockholders' equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

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

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

We also have audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), GeoResources, Inc and subsidiaries' internal control over financial reporting as of December 31, 2009 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 12, 2010 expressed an unqualified opinion that GeoResources, Inc and subsidiaries maintained, in all material respects, effective internal control over financial reporting.

/s/ Grant Thornton LLP
Houston, Texas
March 12, 2010

GEORESOURCES, INC and SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash	$ 12,660	$ 13,967
Accounts receivable		
Oil and gas revenues	14,860	11,439
Joint interest billings and other	13,734	7,172
Affiliated partnerships	933	2,905
Notes receivable	120	120
Derivative financial instruments	764	8,200
Income taxes receivable	2,077	2,165
Prepaid expenses and other	2,297	3,923
Total current assets	47,445	49,891
Oil and gas properties, successful efforts method:		
Proved properties	285,363	204,536
Unproved properties	10,281	2,409
Office and other equipment	828	1,025
Land	96	96
	296,568	208,066
Less accumulated depreciation, depletion and amortization	(48,182)	(26,486)
Net property and equipment	248,386	181,580
Equity in oil and gas limited partnerships	3,532	3,266
Derivative financial instruments	1,360	6,409
Deferred financing costs and other	3,574	2,388
	$ 304,297	$ 243,534

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC and SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

	December 31, 2009	December 31, 2008
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 6,452	$ 10,750
Accounts payable to affiliated partnerships	8,361	10,310
Revenue and royalties payable	13,928	11,701
Drilling advances	390	2,169
Accrued expenses	1,574	1,506
Derivative financial instruments	4,794	1,572
Total current liabilities	35,499	38,008
Long-term debt	69,000	40,000
Deferred income taxes	15,778	17,868
Asset retirement obligations	6,110	5,418
Derivative financial instruments	3,233	1,245
Stockholders' equity:		
Common stock, par value $0.01 per share; authorized 100,000,000 shares; issued and outstanding: 19,705,362 shares in 2009 and 16,236,717 in 2008	197	162
Additional paid-in capital	146,966	112,523
Accumulated other comprehensive income (loss)	(3,288)	7,283
Retained earnings	30,802	21,027
Total stockholders' equity	174,677	140,995
	$ 304,297	$ 243,534

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC. and SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except share and per share amounts)

	Year Ended December 31, 2009	2008	2007
Revenue:			
Oil and gas revenues	$ 71,618	$ 85,263	$ 36,518
Partnership management fees	1,007	1,725	969
Property operating income	1,710	1,430	1,251
Gain on sale of property and equipment	1,355	4,362	49
Partnership income	4,318	1,061	184
Interest and other	420	765	1,144
Total revenue	80,428	94,606	40,115
Expenses:			
Lease operating expense	18,763	22,914	10,818
Severance taxes	3,623	7,517	2,880
Re-engineering and workovers	2,807	3,518	2,092
Exploration expense	1,406	2,592	153
Impairment of oil and gas properties	2,795	8,339	-
General and administrative expense	8,500	7,168	6,513
Depreciation, depletion and amortization	22,409	16,007	7,507
Hedge ineffectiveness	137	(123)	287
Loss on derivative contracts	162	563	-
Interest	4,984	4,820	1,916
Total expense	65,586	73,315	32,166
Income before income taxes	14,842	21,291	7,949
Income taxes:			
Current	412	866	1,472
Deferred	4,655	6,903	3,408
	5,067	7,769	4,880
Net income	$ 9,775	$ 13,522	$ 3,069
Net income per share (basic)	$ 0.59	$ 0.87	$ 0.25
Net income per share (diluted)	$ 0.59	$ 0.86	$ 0.25
Weighted average shares outstanding:			
Basic	16,532,003	15,598,244	12,404,771
Diluted	16,559,431	15,751,185	12,404,771

The accompanying notes are an integral part of these statements

GEORESOURCES, INC. and SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY and COMPREHENSIVE INCOME (LOSS)
Years Ended December 31, 2009, 2008 and 2007
(In thousands, except share data)

	Common Stock Shares	Common Stock Par value	Additional Paid-in Capital	Retained Earning	Accumulated Other Comprehensive Income (Loss)	Total
Balance, January 1, 2007	4,858,000	$ 49	$ 16,849	$ 8,443	$ (1,679)	$ 23,662
Issuance of common stock						
For cash	3,529,500	35	22,597			22,632
Merger transaction, including cash of $886	6,285,477	63	39,473			39,536
For properties	30,406	-	218			218
Comprehensive income (loss):						
Net income				3,069		3,069
Change in fair market value of hedged positions					(20,541)	(20,541)
Net realized hedging losses charged to income					2,910	2,910
Total comprehensive loss						(14,562)
Equity based compensation expense			553			553
Stockholder distributions				(4,007)		(4,007)
Balance, December 31, 2007	**14,703,383**	**147**	**79,690**	**7,505**	**(19,310)**	**68,032**
Issuance of common stock						
For cash, net of issuance costs of $2,313	1,533,334	15	32,172			32,187
For services	5,000	-	35			35
Comprehensive income:						
Net income				13,522		13,522
Change in fair market value of hedged positions, net of taxes					20,019	20,019
Net realized hedging losses charged to income, net of taxes					6,574	6,574
Total comprehensive income						40,115
Equity based compensation expense			626			626
Balance, December 31, 2008	**16,241,717**	**162**	**112,523**	**21,027**	**7,283**	**140,995**
Issuance of common stock						
For cash, net of issuance costs of $2,136	3,450,000	35	33,019			33,054
For services	13,645	-	59			59
Comprehensive income:						
Net income				9,775		9,775
Change in fair market value of hedged positions, net of taxes					(7,123)	(7,123)
Net realized hedging losses charged to income, net of taxes					(3,448)	(3,448)
Total comprehensive loss						(796)
Equity based compensation expense			1,365			1,365
Balance, December 31, 2009	**19,705,362**	**$ 197**	**$ 146,966**	**$ 30,802**	**$ (3,288)**	**$ 174,677**

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC. and SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands, except share and per share amounts)

	Year Ended December 31,		
	2009	2008	2007
Cash flows from operating activities:			
Net income	$ 9,775	$ 13,522	$ 3,069
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	22,409	16,007	7,507
Exploratory dry holes and unproved property impairments	-	2,241	-
Impairment of proved properties	2,795	8,339	-
Gain on sale of property and equipment	(1,355)	(4,362)	(49)
Accretion of asset retirement obligations	368	391	232
Unrealized loss on derivative contracts	(238)	563	-
Amortization of loss on cancelled hedges	482	-	-
Hedge ineffectiveness (gain) loss	137	(123)	287
Partnership income	(4,318)	(1,061)	(184)
Partnership distributions	2,406	653	204
Deferred income taxes	4,655	6,903	3,408
Non-cash compensation	1,424	661	553
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable	(7,923)	3,958	(13,872)
Decrease in notes receivable	275	480	-
Decrease (increase) in prepaid expense and other	(1,116)	(1,990)	(347)
Increase (decrease) in accounts payable and accrued expense	(5,732)	(3,844)	20,056
Net cash provided by operating activities	24,044	42,338	20,864
Cash flows from investing activities:			
Proceeds from sale of property and equipment	1,991	26,789	2,419
Additions to property and equipment	(89,396)	(51,824)	(110,148)
Investment in oil and gas limited partnership	-	(978)	(1,632)
Cancellation of hedge contracts	-	(2,975)	-
Increase in other assets	-	-	(565)
Net cash used in investing activities	(87,405)	(28,988)	(109,926)
Cash flows from financing activities:			
Issuance of common stock	33,054	32,187	23,518
Distributions to stockholders	-	-	(4,007)
Issuance of long-term debt	64,000	-	99,000
Reduction of long-term debt	(35,000)	(56,000)	(9,800)
Debt issuance costs	-	-	(1,436)
Net cash provided by (used in) financing activities	62,054	(23,813)	107,275
Net increase (decrease) in cash and cash equivalents	(1,307)	(10,463)	18,213
Cash and cash equivalents at beginning of period	13,967	24,430	6,217
Cash and cash equivalents at end of period	$ 12,660	$ 13,967	$ 24,430
Supplementary information:			
Interest paid	$ 4,064	$ 5,073	$ 835
Income taxes paid	$ 664	$ 3,970	$ 1,533
Non-cash net assets acquired in merger transactions:			
GeoResources	-	-	$ 23,827
PICA Energy, LLC	-	-	$ 11,703
Yuma property interests	-	-	$ 3,120
Stock issue for services	$ 59	$ 35	-

The accompanying notes are an integral part of these statements.

NOTE A: Organization and Summary of Significant Accounting Policies

Merger

On April 17, 2007, pursuant to the terms of an Agreement and Plan of Merger ("Merger Agreement"), GeoResources, Inc. ("GeoResources" or the "Company"), a Colorado corporation, acquired Southern Bay Oil & Gas, L.P. ("Southern Bay"), a Texas limited partnership, PICA Energy, LLC ("PICA"), a Colorado limited liability company and subsidiary of Chandler Energy, LLC, and certain oil and gas properties in exchange for 10,690,000 shares of common stock (the "Merger"). These transactions resulted in a change in stockholder control of the Company. As a result of the Merger, the former Southern Bay partners received a majority of the outstanding common stock of the Company and thus, obtained voting control of the Company. Accordingly, for financial reporting purposes, the Merger was accounted for as a reverse acquisition of GeoResources and PICA by Southern Bay.

Organization and Basis of Presentation

GeoResources operates a single business segment involved in the acquisition, development and production of, and exploration for, crude oil, natural gas and related products primarily in Texas, North Dakota, Louisiana, Oklahoma, Montana and Colorado.

Summary of Significant Accounting Policies

Basis of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Intercompany accounts and transactions have been eliminated. The Company's investments in oil and gas limited partnerships for which it serves as general partner are accounted for under the equity method.

All events described or referred to as prior to April 18, 2007, relate to Southern Bay as the accounting acquirer.

Cash and Cash Equivalents

Cash and cash equivalents consists of all demand deposits and funds invested in highly liquid investments with an original maturity of three months or less.

The Company maintains its cash and cash equivalents at financial institutions. The combined account balances at several institutions typically exceed Federal Deposit Insurance Corporation ("FDIC") insurance coverage and, as a result, there is a concentration of credit risk related to amounts on deposit in excess of FDIC insurance coverage. Management believes that this risk is not significant.

Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for oil and gas operations whereby cost to acquire mineral investments in oil and gas properties, to drill successful exploratory wells, to drill and equip development wells, and to install production facilities are capitalized. Exploration costs, including unsuccessful exploratory wells and geological and geophysical costs, are charged to operations as incurred. The Company's acquisition and development costs of proved oil and gas properties are amortized using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum engineers.

Oil and gas properties are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flow expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to its estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on expected future cash flows using discount rates commensurate with the risks involved and using prices and costs consistent with those used for internal decision making. Long-lived assets committed by the Company for disposal are accounted for at the lower of cost or fair value, less cost to sell. The Company recognized impairments of $2,795,000 and $9,194,000 for the years ended December 31, 2009 and 2008, respectively. Impairments of $2,795,000 and $8,339,000 were recognized during 2009 and 2008, respectively, on proved properties and are classified as impairments on the Company's income statement. The remaining $855,000 of impairments during 2008 resulted from the write-off of unproved properties during the second and fourth quarters of 2008 and is included in exploration expense on the Company's Consolidated Statement of Income. The Company recognized no impairments for the year ended December 31, 2007.

Office and Other Property

Acquisitions and improvements of office and other property are capitalized at cost; maintenance and repairs are expensed as incurred. Depreciation of equipment is calculated using the straight-line method over the assets estimated useful lives of 5-7 years. Leasehold improvements are amortized over the remaining term of the lease. When assets are sold, retired, or otherwise disposed of, the cost and related accumulated depreciation are eliminated from the accounts and a gain or loss is recognized.

Net Income Per Common Share

Basic net income per common share is computed based on the weighted average shares of common stock outstanding. Net income per share computations to reconcile basic and diluted net income for 2009, 2008 and 2007 consist of the following (in thousands, except per share data):

	Year ended December 31,		
	2009	**2008**	**2007**
Numerator:			
Net income available for common	$ 9,775	$ 13,522	$ 3,069
Denominator:			
Basic weighted average shares	16,532	15,598	12,405
Effect of dilutive securities - options	27	153	-
Diluted weighted average shares	16,559	15,751	12,405
Earning per share			
Basic	$ 0.59	$ 0.87	$ 0.25
Diluted	$ 0.59	$ 0.86	$ 0.25

Options to purchase 726,505 and 25,000 shares were excluded from the diluted earnings per share calculation in 2009 and 2008, respectively, because the options' exercise prices exceeded the average market price of the common shares during the period.

Stock-Based Compensation

The Company recognizes in the financial statements all share-based payments made to employees, including grants of employee stock options, based on their fair values at the time of award.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, accounts receivable and payable and revenue royalties payable are estimated to approximate their fair values due to the short maturities of these instruments. The Company's long-term debt obligation bears interest at floating market rates, so carrying amounts and fair values are approximately equal. Derivative financial instruments are carried at fair value.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes are based on temporary differences between the amount of taxable income and pretax financial income and between the tax bases of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. Tax positions are evaluated for recognition and measurement, with deferred tax balances recorded at their anticipated settlement amounts. A valuation allowance is provided for deferred tax assets not expected to be realized.

Other Comprehensive Income (Loss)

The Company reports comprehensive income on its Consolidated Statement of Stockholders' Equity and Comprehensive Income (Loss). Other comprehensive income (loss) at December 31, 2009, 2008 and 2007 consists of unrealized gains (losses) of commodity hedges qualifying as cash flow hedges in accordance with current accounting standards.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, 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. Oil and gas reserve estimates, which are the basis for units-of-production depreciation, depletion, and amortization are inherently imprecise and are expected to change as future information becomes available.

Derivative Instruments and Hedging Activities

The Company enters into derivative contracts, primarily options, collars and swaps, to hedge future crude oil and natural gas production, as well as interest rates, in order to mitigate the risk of downward movements of oil and gas market prices and the upward movement of interest rates. All derivatives are recognized on the balance sheet and measured at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is deferred in other comprehensive income to the extent the hedge is effective for cash flow hedges. To qualify for hedge accounting, the derivative must qualify either as a fair value, cash flow or foreign currency hedge.

The hedging relationship between the hedged instruments and hedged transactions must be highly effective in achieving the offset of changes in fair values and cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis to qualify for hedge accounting. The Company measures hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively when a hedging instrument becomes ineffective. The Company assesses hedge effectiveness based on total changes in the fair value of options used in cash flow hedges rather than changes in intrinsic value only. As a result, changes in the entire value of option contracts are deferred in accumulated other comprehensive income until the hedged transaction affects earnings to the extent such contracts are effective. Gains and losses that were previously deferred in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered.

Gains and losses resulting from hedge settlements are included in oil and gas revenues and are included in realized prices in the period that the related production is delivered. Gains and losses on hedging instruments that represent hedge ineffectiveness and gains and losses on derivative instruments that do not qualify for hedge accounting are included in other revenues or expenses in the period in which they occur. The resulting cash flows are reported as cash flows from operating activities.

Asset Retirement Obligations

The Company recognizes the present value of the estimated future abandonment costs of its oil and gas properties in both assets and liabilities. If a reasonable estimate of the fair value can be made, the Company will record a liability for legal obligations associated with the future retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of the assets. The fair value of a liability for an asset retirement obligation is recognized in the period in which the liability is incurred. The fair value is measured using expected future cash outflows (estimated using current prices that are escalated by an assumed inflation rate) discounted at the Company's credit-adjusted risk-free interest rate. The liability is then accreted each period until it is settled or the asset is sold, at which time the liability is reversed and any gain or loss resulting from the settlement of the obligation is recorded. The initial fair value of the asset retirement obligation is capitalized and subsequently depreciated or amortized as part of the carrying amount of the related asset.

The Company has recorded asset retirement obligations related to its oil and gas properties. There are no assets legally restricted for the purpose of settling asset retirement obligations.

Revenue Recognition

Revenues represent income from production and delivery of oil and gas, recorded net of royalties. The Company follows the sales method of accounting for gas imbalances. A liability is recorded only if the Company's takes of gas volumes exceed its share of estimated recoverable reserves from the respective well or field. No receivables are recorded for those wells where the Company has taken less than its ownership share of production. Volumetric production is monitored to minimize imbalances, and such imbalances were not significant at December 31, 2009 or 2008.

Accounts Receivable

The Company sells crude oil and natural gas to various customers. In addition, the Company participates with other parties in the operation of crude oil and natural gas wells. Substantially all of the Company's accounts receivable are due from either purchasers of crude oil and natural gas or participants in crude oil and natural gas wells for which subsidiaries of the Company serve as the operator. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells. Crude oil and natural gas sales are generally unsecured.

As is common industry practice, the Company generally does not require collateral or other security as a condition of sale, rather relying on credit approval, balance limitation and monitoring procedures to control the credit use on accounts receivable. The allowance for doubtful accounts is an estimate of the losses in the Company's accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Accounts deemed uncollectible are charged to the allowance. Provisions for bad debts and recoveries on accounts previously charged off are added to the allowance.

Accounts receivable allowance for bad debts was $435,000 at December 31, 2009, and $150,000 at and December 31, 2008. During 2009, the Company wrote-off $27,000 of accounts receivable from joint interest owners against the allowance. Also during 2009, the Company increased the allowance by $312,000 as a result of indentifying additional accounts that may not be fully collectible. During 2008 the Company did not have any activity in its allowance for doubtful accounts.

Recently Issued Accounting Pronouncements

On December 31, 2008, the Securities and Exchange Commission ("SEC") issued *Modernization of Oil and Gas Reporting: Final Rule*, which published the final rules and interpretations updating its oil and gas reporting requirements. The final rule includes updates to definitions in existing oil and gas rules to make them consistent with the petroleum resources management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used in determining reserves. To determine reserves, companies must use a 12-month average price. The Company adopted the new rules effective December 31, 2009, and as a result, it (i) prepared its reserve estimates as of December 31, 2009 based on the new reserves definitions, (ii) has estimated its December 31, 2009 reserve quantities using the 12-month average price and (iii) included additional disclosures as required by the new rule. As a result of the change in reserve pricing from year-end oil and gas prices to now using the 12-month average prices, the Company's total proved reserves at December 31, 2009 were 2,792 MBOE lower than they would have otherwise been if year-end oil and gas prices were used. Oil and gas reserve quantities or their values are a significant component of the Company's depreciation, depletion and amortization ("DD&A"), asset retirement obligation, and impairment analysis. The Company's adoption of the SEC's *Modernization of Oil and Gas Reporting: Final* Rule had an immaterial impact on the Company's asset retirement obligation and impairment analysis; however the significant decrease in proved reserves, due to the change in pricing methodology, had a material impact on the Company's DD&A expenses. Under the prior rules, the Company would have recorded approximately $800,000 less depletion during the fourth quarter of 2009.

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosure* ("ASU 2010-03"), which provides amendments to FASB ASC topic *Extractive Activities – Oil and Gas*. The objective of ASU 2010-03 is to align the oil and gas reserve estimation and disclosure requirements of the FASB ASC with the requirements in the SEC's *Modernization of Oil and Gas Reporting: Final Rule*. The Company adopted ASU 2010-03 in conjunction with its adoption of the SEC's *Modernization of Oil and Gas Reporting: Final Rule*.

In August 2009, the FASB further updated the fair value measurement guidance to clarify how an entity should measure liabilities at fair value. The update reaffirms fair value is based on an orderly transaction between market participants, even though liabilities are infrequently transferred due to contractual or other legal restrictions. However, identical liabilities traded in the active market should be used when available. When quoted prices are not available, the quoted price of the identical liability traded as an asset, quoted prices for similar liabilities or similar liabilities traded as an asset, or another valuation approach should be used. This update also clarifies that restrictions preventing the transfer of a liability should not be considered as a separate input or adjustment in the measurement of fair value. The Company adopted the provisions of this update for fair value measurements of liabilities effective December 31, 2009, with no material impact on our financial position, results of operations and cash flows.

In June 2009, the FASB issued a standard that established the Accounting Standards Codification ("ASC"). The standard also established only two levels of GAAP, authoritative and non-authoritative. The FASB ASC was not intended to change or alter existing GAAP, and the Partnership's adoption effective December 31, 2009, did not therefore have any impact on its financial statements other than to modify references to accounting guidance within certain existing disclosures. The FASB ASC will become the source of authoritative, nongovernmental GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants. All other non-grandfathered, non-SEC accounting literature not included in the FASB ASC will become non-authoritative. FASB ASC is effective for financial statements for interim or annual reporting periods ending after September 15, 2009.

In May 2009, the FASB issued a standard regarding subsequent events that provides guidance as when an entity should recognize events or transactions occurring after a balance sheet date in its financial statements and the necessary disclosures related to these events. Specifically, the entity should recognize subsequent events that provide evidence about conditions that existed at the balance sheet date, including significant estimates used to prepare financial statements. An entity must disclose the date through which subsequent events have been evaluated and whether that date is the date the financial statements were issued or the date the financial statements were available to be issued. The Company adopted this new accounting standard effective June 30, 2009 and has applied its provisions prospectively.

In December 2007, the FASB issued additional guidance regarding business combinations that replaced the initial statement in its entirety. The guidance now additionally requires that all assets and liabilities and non-controlling interests of an acquired business be measured at their fair value, with limited exceptions, including the recognition of acquisition-related costs and anticipated restructuring costs separate from the acquired net assets. The statement also provides guidance for recognizing pre-acquisition contingencies and states that an acquirer must recognize assets and liabilities assumed arising from contractual contingencies as of the acquisition date, measured at acquisition-date fair values, but must recognize all other contractual contingencies as of the acquisition date, measured at their acquisition-date fair values only if it is more likely than not that these contingencies meet the definition of an asset or liability. Furthermore, this statement provides guidance for measuring goodwill and recording a bargain purchase, defined as a business combination in which total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any non-controlling interest in the acquiree, and it requires that the acquirer recognize that excess in earnings as a gain attributable to the acquirer. In April 2009, the FASB issued a further update regarding accounting for assets and liabilities assumed in a business combination that arises from contingencies which amends the previous guidance to require contingent assets acquired and liabilities assumed in a business combination to be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the measurement period. If fair value cannot be reasonably estimated during the measurement period, the contingent asset or liability would be recognized in accordance with U.S. GAAP to account for contingencies and reasonable estimation of the amount of loss, if any. Further, this update eliminated the specific subsequent accounting guidance for contingent assets and liabilities, without significantly revising the original guidance. However, contingent consideration arrangements of an acquiree assumed by the acquirer in a business combination would still be initially and subsequently measured at fair value. The Company adopted this additional guidance regarding business combinations on January 1, 2009 and applied its provisions to the acquisitions completed during 2009.

NOTE B: Signifiant Acquisitions

Bakken Acquisition

In May 2009, the Company closed an acquisition, through an existing joint venture partner, of producing wells and acreage in the Bakken Shale trend of the Williston Basin. The Company acquired a 15% interest in approximately 60,000 net acres, and also acquired 15% of varying working interests in 59 producing and productive wells. The Company's net acquisition cost was approximately $10.4 million, subject to closing adjustments for normal operations activity and other customary purchase price adjustments. The Company funded the acquisition with borrowings from its senior secured revolving credit facility. The amount of revenue from the Acquisition included in the Company's consolidation income statement for the year ended December 31, 2009, was $3,673,000.

Giddings Field Acquisition

On May 29, 2009, effective May 1, 2009, the Company, though its subsidiary, Catena Oil and Gas LLC ("Catena"), entered into a Purchase and Sale Agreement (the "Purchase Agreement") with an affiliated limited partnership, SBE Partners LP (the "Seller") for the acquisition (the "Acquisition") of certain oil and gas producing properties in Giddings field, Grimes and Montgomery Counties, Texas (the "Interests"). Under the Purchase Agreement, the Interests were purchased for a cash purchase price of $48.7 million, net of closing adjustments for normal operations activity (the "Purchase Price"). In addition, the Company also acquired rights to certain post closing severance tax refunds which amounted to $2.4 million. The Acquisition increased the Company's partnership sharing ratio from 2% to 30% in the Seller. Catena is the general partner of the Seller. The Seller distributed to Catena $987,000 of the gross proceeds from the sale. The Acquisition increased the Company's direct working interests in the Interests from a range of 6.5% to 7.8% to a range of 34% to 37%. The Company funded the Purchase Price with borrowings from its senior secured revolving credit facility. The Purchase Agreement contains representations and warranties, covenants, and indemnifications that are customary for oil and gas producing property acquisitions.

The amount of revenue and net income from the Acquisition included in the Company's consolidated income statement for the year ended December 31, 2009, was $6,524,000.

The following summary presents unaudited pro forma information for the years ended December 31, 2009 and 2008, as if the Acquisition had been consummated at January 1, 2008 (in thousands, except share and per share amounts):

	December 31, 2009	December 31, 2008
Total revenue	$ 93,536	$ 124,158
Income before taxes	21,491	38,227
Net income	13,718	24,001
Net income per share:		
Basic	$ 0.83	$ 1.54
Diluted	$ 0.83	$ 1.52
Weighted average shares:		
Basic	16,532,003	15,598,244
Diluted	16,559,431	15,751,185

AROC Energy Acquisition

October 16, 2007, the Company, through a wholly-owned subsidiary, entered into an agreement to purchase ("AROC Energy Purchase Agreement") all of the limited partnership interest in AROC Energy, L.P., an affiliated limited partnership for which the Company served as general partner. The limited partner was an unaffiliated entity. Prior to this transaction, the Company owned 2% of the partnership and the limited partner owned the remaining 98%. This acquisition, which was accounted for as a purchase, included oil and gas properties located in Louisiana, the Gulf Coast, South Texas, the Permian Basin and the Black Warrior Basin. Under the AROC Energy Purchase Agreement, the Company purchased the interest for a cash purchase price of $91,100,000 and paid $12,952,000 to cancel the limited partnership's oil and gas hedge contracts. In November 2007, the Company dissolved the limited partnership.

Other Acquisitions and Dispositions

In May 2008, Southern Bay, through Catena, formed an entity in connection with the acquisition of producing oil and gas properties located throughout Oklahoma. OKLA Energy Partners LP ("OKLA") was formed with Catena as general partner with a 2% partnership interest, and a large institutional investor as the sole limited partner with a 98% partnership interest. These entities paid cash of $61.7 million to acquire these properties. Catena, purchased 18% of the interests and OKLA purchased the remaining 82%. Catena's share of the property purchase price was $12.8 million, and its general partner contribution to OKLA was $978,000. The Company's investment in OKLA is accounted for under the equity method of accounting.

In January 2008, the Company sold all of its interest in the Grand Canyon Unit, a property acquired in the Merger. This property, located in Otsego County, Michigan, was sold to an unaffiliated party for $6.6 million in cash. The carrying value of this property at the date of the sale was equal to the selling price; therefore, no gain or loss was recognized on sale.

In February 2008, the Company acquired producing properties in the Williston Basin of North Dakota and Montana from an unaffiliated party for $7.9 million in cash. The acquired properties are operated by the Company. The purchase price was allocated to oil and gas properties.

In February 2008, the Company sold its interests in certain non-core oil and gas properties located in Louisiana to unaffiliated parties for $1.8 million in cash and recognized gains of $430,000.

In May 2008, the Company closed certain property sales. These sales consisted of seven non-core fields in Louisiana and Texas and were sold to unaffiliated parties for approximately $11.8 million. The Company recognized a gain of $1.5 million related to these sales.

In September 2008, the Company acquired certain producing properties in Oklahoma from an unaffiliated party for $3.6 million in cash. The acquired properties are operated by the Company. The purchase price was allocated to oil and gas properties.

During 2008, the Company identified an exploration opportunity and began leasing in various counties in Colorado and Utah targeting the Gothic Shale as a newly emerging resource play with multiple other objectives. In November, 2008, the Company sold the majority of its interest for $6 million and recognized a gain of $2.5 million. The Company retained an overriding royalty interest or the option to participate, under certain circumstances, for up to 12.5% working interest.

In January 2009, the Company sold a producing property located in Louisiana to an unaffiliated party for $1.6 million. The Company recognized a gain of $1.3 million in conjunction with this sale.

On August 29, 2009, the Company, through its subsidiary, Catena, received a distribution of proved undeveloped property and unproved acreage in the Giddings field from SBE Partners LP ("SBE"), an affiliated partnership. The property was recorded at the estimated fair market value of $1.6 million, which exceeded its carrying value in the partnership. In conjunction with the distribution, SBE recorded a gain. The Company, which accounts for SBE as an equity method investment, included its share of the gain, $1,037,000, in partnership income.

NOTE C: Long-term Debt

On October 16, 2007, the Company entered into an Amended and Restated Credit Agreement ("Amended Credit Agreement") with Wachovia Bank (the "Bank") as Administrative agent, Issuing Bank, Sole Lead Arranger and Sole Bookrunner. The Amended Credit Agreement provided for financing of up to $200 million to the Company. The initial borrowing base of the Amended Credit Agreement was $110. On September 30, 2008, the borrowing base was reduced to $95 million. On November 5, 2008, the borrowing base was increased to $100 million and on April 6, 2009, the $100 million borrowing base was reaffirmed by the Bank.

On July 13, 2009, the Company entered into a Second Amended and Restated Credit Agreement ("Second Amended Credit Agreement"). The Second Amended Credit Agreement increased the facility from $200 million to $250 million and extended the term of the agreement to October 16, 2012. The initial borrowing base of the facility was $135 million and was increased to $145 million in November 2009. The borrowing base is subject to redetermination on May 1 and November 1 of each year. The Second Amended Credit Agreement provides for interest rates at (a) LIBOR plus 2.25% to 3.00% or (b) the prime lending rate plus 1.25% to 2.00%, depending upon the amount borrowed. The Second Amended Credit Agreement also requires the payment of commitment fees to the lender in respect of the unutilized commitments. The commitment rate is 0.50% per annum. The Company is also required to pay customary letter of credit fees. All of the obligations under the Second Amended Credit Agreement, and the guarantees of those obligations, are secured by substantially all of the Company's assets.

The Second Amended Credit Agreement contains a number of covenants that, among other things, restrict, subject to certain exceptions, the Company's ability to incur additional indebtedness, create liens on assets, make investments, enter into sale and lease back transactions, pay dividends and distributions or repurchase its capital stock, engage in mergers or consolidations, make significant changes to management, sell certain assets, sell or discount any notes receivable or accounts receivable and engage in certain transactions with affiliates. In addition, the Second Amended Credit Agreement requires the maintenance of certain financial ratios, contains customary affirmative covenants, and provides for customary events of default. The Company was in compliance with all covenants at December 31, 2009.

The principal outstanding under the Second Amended Credit Agreement was $69 million and $40 million at December 31, 2009 and 2008, respectively. The annual interest rate in effect at December 31, 2009 was 2.74% on the entire amount of outstanding principal. The remaining borrowing capacity under the Second Amended Credit

Agreement was $76 million. The maturity date for amounts outstanding under the Seconded Amended Credit Agreement is October 16, 2012.

Interest expense for 2009, 2008 and 2007 includes amortization of deferred financing costs of $785,000, $491,000 and $146,000, respectively.

In October 2007, the Company entered into an interest rate swap agreement with the Bank, providing a fixed rate of 4.79% on a notional $50 million through October 16, 2010. During 2008, the Company broke the swap up into two pieces, a $40 million swap and a $10 million swap each with a fixed annual interest rate of 4.29%. The $40 million swap is accounted for as a cash flow hedge while the $10 million swap is accounted for as a trading security. The fair market value of these swaps at December 31, 2009, was a liability of $1,627,000 all of which was classified as a current liability. The fair market value of the two swaps at December 31, 2008 was a liability of $2,817,000 of which $1,572,000 was classified as a current liability. The Company also recognized a net loss of $162,000 on the $10 million swap during the year ended December 31, 2009. This loss was due to cash settlement losses of $399,000 which were offset by a mark-to-market gain of $237,000. During the year ended December 31, 2008, the Company recognized a net loss of $563,000 on the $10 million swap.

At December 31, 2009 and 2008, accumulated other comprehensive income included unrecognized losses of $1,302,000, net of a tax benefit of $530,000, and $1,394,000, net of a tax benefit of $859,000, respectively. These unrecognized losses represent the inception to date change in mark-to-market value of the Company's $40 million interest rate swap, designated as a hedge, as of the balance sheet date. For the year ended December 31, 2009, the Company recognized realized cash settlement losses of $1,598,000 related to the $40 million swap. For the year ended December 31, 2008, the Company recognized realized cash settlement losses of $656,000 related to the $50 million swap which as discussed above was split into a $40 million and $10 million swap. The Company did not have any settlement losses related to its interest rate swap in 2007. Based on the estimated fair market value of the Company's $40 million interest rate swap contract designated as a hedge at December 31, 2009, the Company expects to reclassify net losses of $1.3 million into earnings from accumulated other comprehensive income (loss) during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially.

The weighted average interest rate on borrowings outstanding, inclusive of amortization of deferred financing costs and interest rate swaps, during 2009, 2008, and 2007 was 6.70%, 7.20% and 7.63%, respectively.

NOTE D: Stock Options, Performance Awards and Stock Warrants

In March 2007, the shareholders of the Company approved the GeoResources, Inc, Amended and Restated 2004 Employees' Stock Incentive Plan (the "Plan"), which authorizes the issuance of options and other stock-based incentives to officers, employees, directors and consultants of the Company to acquire up to 2,000,000 shares of the Company's common stock at prices which may not be less than the stock's fair market value on the date of grant. The options can be designated as either incentive options or nonqualified options.

On October 10, 2007, and November 10, 2007, the Company granted options under the Plan to officers and key employees to purchase 755,000 and 10,000 shares of common stock, respectively. These options have exercise prices ranging from $8.27 to $9.56 per share and have vesting dates ranging from October 10, 2009, to November 15, 2011. On June 19, 2008, the Company granted options to employees to purchase 25,000 shares of common stock. These options have exercise prices ranging from $22.50 to $25.00 per share and have vesting dates ranging from June 19, 2010 to June 19, 2012.

The closing market prices of the Company's common stock on the date of the October and November 2007 grants were $7.20 and $8.65, respectively. The closing market price of the Company's common stock on the date of the June 2008 grant was $20.99.

On February 3, 2009, and March 26, 2009, the Company granted options under the Plan to officers and other employees to purchase 300,000 and 225,000 shares of common stock, respectively. Also on February 3, 2009, the Company granted options to outside directors to purchase 200,000 shares of common stock. On October 20, 2009, the Company granted options to certain employees to purchase 25,000 shares of common stock. The following is a summary of the terms of these grants by exercise price:

	2009 Stock Option Grants				
Vesting Date	$8.50	$10.00	$ 13.50	$ 15.00	Total
Officers and Employees					
February 3, 2010	65,625	65,625			131,250
October 20, 2010			3,125	3,125	6,250
February 3, 2011	65,625	65,625			131,250
October 20, 2011			3,125	3,125	6,250
February 3, 2012	65,625	65,625			131,250
October 20, 2012			3,125	3,125	6,250
February 3, 2013	65,625	65,625			131,250
October 20, 2013			3,125	3,125	6,250
Directors					
February 3, 2010	25,000	25,000			50,000
February 3, 2011	25,000	25,000			50,000
February 3, 2012	25,000	25,000			50,000
February 3, 2013	25,000	25,000			50,000
Total	362,500	362,500	12,500	12,500	750,000

The closing market prices of the Company's common stock on the date of the February, March and October 2009 grants were $7.62, $7.16, and $12.70, respectively.

The options, if not exercised, will expire 10 years from the date of grant.

A summary of the Company's stock option activity for the years ended December 31, 2009 and 2008 is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (year)	Weighted Average Fair Value	Aggregate Intrinsic Value
Outstanding, January 1, 2007	-	-	-	-	-
Granted	765,000	$ 8.92		$ 2.14	
Exercised	-			-	
Forfeited	-			-	
Outstanding, December 31, 2007	765,000	$ 8.92	9.78	$ 2.15	$ 275,575
Granted	25,000	$ 23.75		$ 6.82	
Exercised	-	$ -		-	
Forfeited	-	$ -		-	
Outstanding, December 31, 2008	790,000	$ 9.39	8.81	$ 2.29	$ 158,750
Granted	750,000	$ 9.42		$ 4.45	
Exercised	-	$ -		-	
Forfeited	-	$ -		-	
Outstanding, December 31, 2009	1,540,000	$ 9.40	8.30	$ 3.34	$ 6,827,275
Exercisable at year-end					
2009	382,500				
2008	-				
2007	-				

The weighted average grant date fair value of the options that vested during the year was $2.31 per option. These vested options have a weighted average exercise price of $8.27 and a weighted average remaining life of 8.27.

Unvested options at year-end:

	Number of Awards	Weigthed Average Exercise Price	Weighted Average Fair Value
December 31, 2007	765,000	$ 8.92	$ 2.15
December 31, 2008	790,000	$ 9.39	$ 2.29
December 31, 2009	1,157,500	$ 9.77	$ 3.69

The Company recognized compensation expense based upon the fair value of the options at the date of grant determined by the Black-Scholes option pricing model. For the years ended December 31, 2009, 2008, and 2007, the Company recognized compensation expense of $1,365,000, $626,000, $131,000, respectively, related to these options. As of December 31, 2009, the future pre-tax expense of non-vested stock options is $2,960,000 to be recognized through the fourth quarter of 2013.

During 2009, 2008 and 2007 the weighted-average fair value of the options granted during the year was $4.45 per share, $6.82 per share, and $2.14 per share respectively, using the following assumptions:

	2009	2008	2007
Risk-free interest rate	1.27%	2.25%	4.25%
Dividend yield	None	None	None
Volatility	86%	52%	40%
Expected life of option	4 Years	4 Years	4 Years

In measuring compensation associated with these options, an annual pre-vesting forfeiture rate of 1% was used.

NOTE E: Income Taxes

The following table shows the components of the Company's income tax provision for 2009, 2008 and 2007:

	Year ended December 31,		
	2009	2008	2007
		(in thousands)	
Current:			
Federal	$ 283	$ 695	$ 1,348
State	129	171	124
Total current	412	866	1,472
Deferred			
Federal	4,318	6,186	3,103
State	337	717	305
Total deferred	4,655	6,903	3,408
Total	$ 5,067	$ 7,769	$ 4,880

The following is a reconciliation of taxes computed at the corporate federal statutory income tax rate of 35% in 2009 and 2008 and 34% in 2007 to the reported income tax provision for the years ended December 31, 2009, 2008 and 2007:

	2009	2008	2007
		(in thousands)	
Income before income taxes	$ 14,842	$ 21,291	$ 7,949
Tax computed at federal statutory rate	$ 5,195	$ 7,452	$ 2,703
Statutory depletion in excess of tax basis	-	(562)	-
Domestic production activities deduction	-	(113)	-
Non-taxable Southern Bay income prior to Merger	-	-	(303)
Deferred income taxes arising from change in tax status of Southern Bay	-	-	2,214
State income taxes, net of federal benefit	521	716	250
Expense not deductible for tax purposes and other	(649)	276	16
Total income tax expense	$ 5,067	$ 7,769	$ 4,880
Effective tax rate	34.14%	36.49%	61.39%

Deferred income taxes are recognized for the tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and tax purposes, as required by current accounting standards. The deferred tax is measured using the enacted tax rates applicable to periods when these differences are expected to reverse.

The deferred income tax provision for 2007 includes an initial charge of $2,214,000 attributable to Southern Bay becoming a taxable entity in April 2007, concurrent with the Merger. Generally accepted accounting principles require the recognition of deferred taxes attributable to temporary differences existing at the date of a change in status of an entity from nontaxable to taxable.

The following table shows the components of the Company's net deferred tax liability at December 31, 2009, 2008 and 2007:

	2009	2008	2007
Deferred tax asset or (liability)		(in thousands)	
Current:	$ -	$ -	$ -
Noncurrent:			
Oil and gas properties	(20,178)	(15,334)	(9,457)
Other property and equipment	473	(101)	(37)
Equity in limited partnerships	(685)	(249)	(89)
Asset retirement obligations	1,703	2,066	2,908
Stock-based compensation	518	204	-
Price-risk management liability	2,391	(4,488)	-
Other	-	34	199
Net deferred tax liability	$ (15,778)	$ (17,868)	$ (6,476)

As of December 31, 2009 and 2008, the Company had statutory depletion available for carryforward of approximately $1.1 million and $5.1 million, respectively, which may be used to offset future taxable income. The amount that may be used in any year is subject to limitations arising from a change in control resulting from the Merger.

Uncertain Tax Positions

The Company will consider a tax position settled if the taxing authority has completed its examination, the Company does not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. The Company uses the benefit recognition model which contains a two-step approach, a more likely than not recognition criteria and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. The amount of interest expense recognized by the Company related to uncertain tax positions is computed by applying the applicable statutory rate of interest to the difference between the tax position recognized and the amount previously taken or expected to be taken in a tax return.

At December 31, 2009, the Company did not have any uncertain tax positions that would require recognition. The Company's uncertain tax positions may change in the next twelve months; however, the Company does not expect any possible change to have a significant impact on its results of operations or financial position.

The Company files a consolidated federal income tax return and various combined and separate filings in several state and local jurisdictions.

The Company's continuing practice is to recognize estimated interest and penalties, if any, related to potential underpayment of income taxes as a component of income tax expense in its Consolidated Statement of Income. As of December 31, 2009, the Company did not have any accrued interest or penalties associated with any uncertain tax liabilities. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statutes of limitations prior to December 31, 2010.

NOTE F: Derivative Financial Instruments

The Company enters into various crude oil and natural gas hedging contracts, primarily costless collars and swaps, in an effort to manage its exposure to product price volatility. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. The Company has designated its commodity derivative contracts as cash flow hedges designed to achieve more predictable cash flows, as well as to reduce its exposure to price volatility. While the use of derivative instruments limits the downside risk of adverse price movements, they also limit future revenues from favorable price movements. The Company does not enter into commodity derivative instruments for speculative or trading purposes.

At December 31, 2009, accumulated other comprehensive income (loss) included unrecognized losses of \$2,516,000, net of taxes of \$1,727,000, representing the inception to date change in mark-to-market value of the effective portion of the Company's open commodity contracts, designated as cash flow hedges, as of the balance sheet date. At December 31, 2008, accumulated other comprehensive income (loss) included unrecognized gains of \$8,677,000, net of taxes of \$5,348,000. For the year ended December 31, 2009, the Company recognized realized cash settlement gains on commodity derivatives of \$7,434,000. For the years ended December 31, 2008, and 2007, the Company recognized realized cash settlement losses on commodity derivatives of \$9,970,000 and \$2,910,000, respectively. Based on the estimated fair market value of the Company's derivative contracts designated as hedges at December 31, 2009, the Company expects to reclassify net losses of \$2,403,000 into earnings from accumulated other comprehensive income (loss) during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially.

On October 17, 2008, the Company paid \$2,975,000 to cancel its 2009 natural gas swaps that were previously accounted for as cash flow hedges. At the time of cancelation, accumulated other comprehensive (loss) contained \$482,000 of acquisition to date change in mark-to-market of the effective portion of these commodity derivative contracts. These accumulated losses were amortized during 2009 and reduce net income by \$482,000. The remainder of the cost to cancel was previously recognized as part of the AROC Energy acquisition or through ineffectiveness charges. The canceled swaps were acquired as part of the AROC Energy acquisition discussed in Note B.

During the first quarter of 2009, the Company entered into two natural gas swap contracts and one crude oil fixed price forward sale contract. The natural gas swaps have fixed prices of \$4.86 and \$4.87 per MMBTU. The term of the contracts is from April 2009 to March 2010 and each contract is for 50,000 MMBTUs per month. The fixed price crude oil contract is directly associated with the Company's Williston Basin production. Under this agreement the Company will sell 9,000 Bbls per month from April 2009 to March 2010 at a price of \$43.85. During the second quarter of 2009, the Company entered into two additional natural gas swap contracts. The natural gas swaps have fixed prices of \$5.16 and \$5.20 per MMBTU. The term of the contracts is from July 2009 to December 2010. The \$5.16 contract is for 180,000 MMBTUs per month for July 2009 to December 2009 and 120,000 MMBTUs per month during 2010. The \$5.20 contract is for 70,000 MMBTUs per month for July 2009 to December 2009 and 40,000 MMBTUs per month during 2010. During the fourth quarter of 2009, the Company entered into an additional natural gas swap. This swap has fixed price ranging from \$6.065 to \$6.450. The term of the contract is from April 2010 to December 2012 and has volumes ranging from 40,000 MMBTUs per month to 70,000 MMBTUs per month.

At December 31, 2009, the Company had hedged its exposure to the variability in future cash flows from forecasted oil and gas production volumes as follows:

	Total Remaining Volume	Floor Price	Ceiling / Swap Price
Crude Oil Contracts (Bbls):			
Swap contracts:			
2010	322,000		$ 74.710
2011	282,000		$ 74.730
Forward sales contracts:			
2010	27,000		$ 43.850
Natural Gas Contracts (Mmbtu)			
Swap contracts:			
2010	150,000		$ 4.860
2010	150,000		$ 4.870
2010	1,440,000		$ 5.155
2010	480,000		$ 5.195
2010	360,000		$ 6.065
2011	210,000		$ 6.065
2011	630,000		$ 6.450
2012	150,000		$ 6.450
2012	450,000		$ 6.415
Costless collar contracts:			
2010	1,287,000	$ 7.000	$ 9.900
2011	1,079,000	$ 7.000	$ 9.200

Subsequent to year-end, the Company entered into an additional oil swap. The term of the contract is from February 2010 to December 2011. The swap has fixed prices of $85.32 per Bbl during 2010 and $88.45 per Bbbl for 2011. The contract is for 10,000 Bbls per month for February 2010 to December 2010 and 7,000 Bbls per month during 2011.

The fair market value of these gas hedge contracts at December 31, 2009 was an asset of $2,124,000 of which $764,000 was classified as a current asset. The fair market value of these oil hedge contracts was a liability of $6,400,000 of which $3,167,000 was classified as a current liability. The fair market value of the Company's hedge contracts at December 31, 2008 was an asset of $14,609,000, of which $8,200,000 was classified as a current asset. During the year ended December 31, 2009, the Company recognized a loss of $137,000 due to hedge ineffectiveness on these commodity hedge contracts versus a gain of $123,000 during 2008. During the year ended December 31, 2007, the Company recognized a loss of $287,000 due to hedge ineffectiveness.

The Company has also entered into an interest rate swap designated as a cash flow hedge as discussed in Note C above.

All derivative instruments are recorded on the consolidated balance sheet of the Company at fair value. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands):

Derivatives designated as ASC 815 hedges:	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	Dec. 31, 2009	Dec. 31, 2008	Balance Sheet Location	Dec. 31, 2009	Dec. 31, 2008
Commodity contracts	Current derivative financial instruments asset	$ 764	$ 8,200	Current derivative financial instruments liability	$ (3,167)	$ -
Commodity contracts	Long-term derivative financial instruments asset	1,360	6,409	Long-term derivative financial instruments liability	(3,233)	-
Interest rate swap contract	Current derivative financial instruments asset	-	-	Current derivative financial instruments liability	(1,302)	(1,258)
Interest rate swap contract	Long-term derivative financial instruments asset	-	-	Long-term derivative financial instruments liability	-	(996)
		$ 2,124	$ 14,609		$ (7,702)	$ (2,254)

Derivatives not designated as ASC 815 hedges:	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	Dec. 31, 2009	Dec. 31, 2008	Balance Sheet Location	Dec. 31, 2009	Dec. 31, 2008
Interest rate swap contract	Current derivative financial instruments asset	$ -	$ -	Current derivative financial instruments liability	$ (325)	$ (314)
Interest rate swap contract	Long-term derivative financial instruments asset	-	-	Long-term derivative financial instruments liability	-	(249)
		$ -	$ -		$ (325)	$ (563)

Derivative contracts – The following tables summarize the effects of commodity and interest rate derivative instruments on the consolidated statements of income for the years ended December 31, 2009, 2008 and 2007 (in thousands):

Derivatives designated as ASC 815 hedges:	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)		
	2009	2008	2007
Commodity contracts	$ (10,834)	$ 22,511	$ (20,541)
Interest rate swap contracts	(646)	(2,055)	-
	$ (11,480)	$ 20,456	$ (20,541)

Derivatives designated as ASC 815 hedges:	Amount of Gain or (Loss) Reclassified from OCI into Income (Effective Portion)			Location of Gain or (Loss) Reclassifed from OCI into Income (Effective Portion)
	2009	2008	2007	
Commodity contracts	$ 7,434	$ (9,970)	$ (2,910)	Oil and gas revenues
Interest rate swap contracts	(1,598)	(656)	-	Interest expense
	$ 5,836	$ (10,626)	$ (2,910)	

Derivatives in ASC 815 cash flow hedging relationships:	Location of (Gain) or Loss Recognized in Income on Derivative (Ineffective Portion)	Amount of (Gain) or Loss Recognized in Income on Derivative (Ineffective Portion)		
		2009	2008	2007
Commodity contracts	Hedge ineffectivenss	$ 137	$ (123)	$ 287

Derivative not designated as ASC 815 hedges:	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative		
		2009	2008	2007
Realized cash settlements on interst rate swap	Loss on derivative contracts	$ 399	$ -	$ -
Unrealized (gain) on commodity contracts	Loss on derivative contracts	(237)	563	-
		$ 162	$ 563	$ -

Contingent features in derivative instruments – None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's derivative contracts are high credit quality financial institutions.

NOTE G: Fair Value Disclosures

ASC Topic 820 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

ASC Topic 820 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3 – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of the input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The tables below present information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2009 and 2008, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value.

Cash, Cash Equivalents, Accounts Receivable and Payable and Revenue Royalties – The carrying amount of cash and cash equivalents, accounts receivable and payable and royalties payable are estimated to approximate their fair values due to the short maturities of these instruments.

Long-term Debt – The Company's long-term debt obligation bears interest at floating market rates, so carrying amounts and fair values are approximately equal.

Derivative Financial Instruments – Derivative financial instruments are carried at fair value. Commodity derivative instruments consist of costless collars and swaps for crude oil and natural gas. The Company's costless collars are valued based on the counterparty's marked-to-market statements, which are validated by observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. The Company's swaps are valued based on a discounted future cash flow model. The primary input for the model is the NYMEX futures index. The Company's model is validated by the counterparty's marked-to-market statements. The swaps are also designated as Level 2 within the valuation hierarchy. The discount rate used in determining the fair values of these instruments includes a measure of nonperformance risk. The Company's interest rate swaps are valued using the counterparty's marked-to-market statement, which can be validated using modeling techniques that include market inputs such as publicly available interest rate yield curves, and is designated as Level 2 within the valuation hierarchy.

Derivative Assets and Liabilities - December 31, 2009
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2009
Current portion of derivative financial instrument asset (1)	-	$ 764	-	$ 764
Long-term portion of derivative financial instrument asset (1)	-	1,360	-	1,360
Current portion of derivative financial instrument liability (2)	-	(4,794)	-	(4,794)
Long-term portion of derivative financial instrument liability (1)	-	(3,233)	-	(3,233)

(1) Commodity derivative instruments accounted for as cash flow hedges.
(2) Includes a $40 million interest rate swap accounted for as a cash flow hedge ($1,302,000), a $10 million interest rate swap accounted for as a trading security ($325,000) and a commodity derivative accounted for as a cash flow hedge ($3,167,000).

Derivative Assets and Liabilities - December 31, 2008
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2008
Current portion of derivative financial instrument asset (1)	-	$ 8,200	-	$ 8,200
Long-term portion of derivative financial instrument asset (1)	-	6,409	-	6,409
Current portion of derivative financial instrument liability (2)	-	(1,572)	-	(1,572)
Long-term portion of derivative financial instrument liability (3)	-	(1,245)	-	(1,245)

(1) Commodity derivative instruments accounted for as cash flow hedges.
(2) Includes a $40 million interest rate swap accounted for as a cash flow hedge ($1,258,000) and a $10 million interest rate swap accounted for as a trading security ($314,000).
(3) Includes a $40 million interest rate swap accounted for as a cash flow hedge ($996,000) and a $10 million interest rate swap accounted for as a trading security ($249,000).

At December 31, 2009 and 2008, the Company did not have any assets or liabilities measured at fair value on a recurring basis that meet the definition of Level 1 or Level 3.

Asset Impairments – The Company reviews proved oil and gas properties for impairment when events and circumstances indicate a significant decline in the recoverability of the carrying value of such properties. When events and circumstances indicate a significant decline in the recoverability of a property, the Company estimates the future cash flows expected in connection with the property and compares such future cash flows to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

The Company recorded asset impairments of $2,795,000 on proved properties during the year ended December 31, 2009. During the year December 31, 2008, the Company recorded impairments of $855,000 on unproved properties and $8,339,000 on proved properties. All the 2009 impairments and the 2008 impairments on proved properties were included in impairment expense while the 2008 impairments on unproved properties, due to the nature of the expenses, were included in exploration expense. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of future natural gas and crude oil prices, operating and development costs, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

Asset Retirement Obligations – The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of the Company's asset retirement obligation is presented in Note I.

Property Acquisitions and Business Combinations – The Company records the identifiable assets acquired, liabilities assumed and any non-controlling interests at fair value at the date of acquisition. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the determination of fair value of the acquisition include the Company's estimate of future natural gas and crude oil prices, operating and development costs, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. The Company's acquisitions are discussed in Note B.

NOTE H: Public Offering of Common Stock and Private Placement Offering

On June 5, 2008, the Company issued 1,533,334 shares of common stock and 613,336 warrants to purchase common stock to non-affiliated accredited investors pursuant to exemptions from registration under federal and state securities laws. The shares of common stock were sold for $22.50 per share. The warrants have a term of five years from issuance with an exercise price of $32.43. The gross proceeds to the Company of $34.5 million were reduced by placement fees and issue costs of $2.3 million.

On December 1, 2009, the Company closed a public offering of 3,450,000 shares of common stock at a public offering price of $10.20 per share. The gross proceeds to the Company of $35.2 million were reduced by underwriters' fees and issue costs of $2.1 million.

NOTE I: Asset Retirement Obligations

The Company's asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells, and removal of equipment and facilities from leased acreage and land restoration, in accordance with applicable local, state and federal laws. The Company determines its obligation by calculating the present value of estimated cash flows related to plugging and abandonment obligations. The changes to the Asset Retirement Obligations ("ARO") for oil and gas properties and related equipment during the years ended December 31, 2009 and 2008 are as follows (in thousands):

	Year ended December 31	
	2009	2008
Balance, beginning of year	$ 5,418	$ 7,827
Additional liabilities incurred	262	158
Accretion expense	368	391
Costs incurred	-	(69)
Disposals of properties	(188)	(3,019)
Revisions of estimates	250	130
Balance, end of year	$ 6,110	$ 5,418

NOTE J: Concentration of Credit Risk

Credit risk represents the accounting loss which the Company would record if its customers failed to perform pursuant to the contractual terms. The Company's largest customers are large companies. In addition, the Company transacts business with independent oil producers, crude oil trading companies and a variety of other entities. The Company's credit policy and the relatively short duration of receivables mitigate the risk of uncollected receivables.

In 2009, one purchaser accounted for 17% of the Company's consolidated oil and gas revenues, two purchasers accounted for 15% each, and one more accounted for 11%. In 2008, one purchaser accounted for 16% of the Company's consolidated oil and gas revenue, two more accounted for 11% each and two purchasers accounted for 10% each. In 2007, two purchasers accounted for 17% and 14% of consolidated oil and gas revenues. No other single purchaser accounted for 10% or more of the Company's consolidated oil and gas revenues in 2009, 2008, or 2007. There are adequate alternate purchasers of production such that the loss of one or more of the above purchasers would not have a material adverse effect on the Company's results of operations or cash flows.

NOTE K: Commitments and Contingencies

Commitments

The Company is obligated under non-cancelable operating leases for its office facilities as follow (in thousands):

2010	$ 317
2011	225
2012	227
2013	235
2014	242
Thereafter	82
	$ 1,328

Total rental expense under operating leases for 2009, 2008 and 2007 was $374,000, $324,000 and $246,000, respectively.

Contingencies

No significant legal proceedings are pending which are expected to have a material adverse effect on the Company. The Company is unaware of any potential claims or lawsuits involving environmental, operating or corporate matters which are expected to have a material adverse effect on the Company's financial position or results of operations.

NOTE L: Related Party Transactions

Accounts receivable at December 31, 2009 and 2008, includes $785,000 and $2,311,000, respectively, due from SBE Partners LP ("SBE Partners"). Accounts receivable at December 31, 2009 and 2008, also includes $148,000 and $594,000, respectively, due from OKLA Energy Partners LP ("OKLA Energy"). Both of these partnerships are oil and gas limited partnerships for which a subsidiary of the Company serves as general partner. These amounts represent the limited partnerships' share of property operating expenditures incurred by operating subsidiaries of the Company on their behalf, as well as accrued management fees. Accounts payable at December 31, 2009 and 2008, includes $7,583,000 and $9,333,000, respectively, due to SBE Partners for oil and gas revenues and severance tax refunds collected on its behalf. Accounts payable at December 31, 2009 and 2008, also includes $778,000 and $977,000, respectively due to OKLA Energy for oil and gas revenues collected on its behalf.

The Company earned partnership management fees during the years ended December 31, 2009, 2008, and 2007 of $1,007,000, $1,725,000, and $969,000, respectively.

Subsidiaries of the Company operate the majority of oil and gas properties in which the two limited partnerships have an interest. Under this arrangement, the Company collects revenues from purchasers and incurs property operating and development expenditures on each partnership's behalf. These revenues are paid monthly to each partnership, which in turn reimburses the Company for the partnership's share of expenditures.

In May 2009, the Company, through its subsidiary, Catena, entered into a Purchase and Sale Agreement with an affiliated limited partnership, SBE Partners. Catena purchased the properties for $49,340,000. As the General Partner of SBE Partners, Catena received a distribution from the partnership as a result of the sale of $987,000. The net purchase price for the properties was $48,353,000. This acquisition is discussed in Note B above.

NOTE M: Equity Investments

The Company holds investments, in the form of general partnership interests, in two affiliated partnerships, SBE Partners and OKLA Energy. The Company accounts for these investments using the equity method of accounting. Under this accounting method the Company records its share of income and expenses. Contributions to the investment increase the Company's investment while distributions from the partnership decrease the Company's carrying value of the investment.

OKLA Energy, formed during 2008, holds direct working interests in producing oil and gas properties located throughout Oklahoma. GeoResources' 2% general partner interest reverts to 35.66% when the limited partner realizes a contractually specified rate of return. The Company recorded a loss in partnership income related to this investment for the year ended December 31, 2009 of $34,000. For the year ended December 31, 2008 the Company recorded income of $16,000.

SBE Partners, formed during 2007, holds direct working interests in producing oil and gas properties located in Giddings field in Texas. Previously, GeoResources held a 2% general partner interest which increased after reaching a cumulative payout. As result of the sale of certain properties and subsequent distribution of proceeds by the Partnership cumulative payout was achieved and the Company's general partner interest increased to 30%. For further information about the sale see Note B above. For the years ended December 31, 2009, 2008 and 2007 the Company recorded partnership income of $4,352,000, $1,045,000, and $453,000 respectively.

The Company's carrying value for its equity investment in OKLA Energy at December 31, 2009 and 2008 was $846,000 and $993,000, respectively. The Company's carrying value for its equity investment in SBE Partners at December 31, 2009 and 2008 was $2,686,000 and $2,273,000, respectively.

The following is a summary of selected financial information of SBE Partners, LP as of and for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	2009	2008	2007 [1]
Summary of Partnership selected balance sheet information:			
Current assets	$ 11,933	$ 23,009	$ 13,247
Oil and gas properties, net	$ 60,834	$ 98,757	$ 84,961
Total assets	$ 73,686	$ 123,686	$ 98,208
Current liabilities	$ 1,047	$ 2,348	$ 4,913
Total liabilities	$ 1,876	$ 3,343	$ 11,768
Partner's capital	$ 71,810	$ 120,343	$ 86,440
Summary of Partnership operations:			
Revenues	$ 52,429	$ 82,721	$ 44,233
Income from continuing operations	$ 29,726	$ 51,060	$ 22,971
Net income	$ 29,726	$ 51,060	$ 22,971
The company's equity in partnership net income	$ 4,352	$ 1,045	$ 453
The company's capital balance in the partnership	$ 2,686	$ 2,273	$ 1,881

(1) The income statement amounts for 2007 are for the period from January 15, 2007 (inception) to December 31, 2007.

NOTE N: Supplemental Financial Quarterly Results (Unaudited):

The sum of the individual quarterly basic and diluted earnings (loss) per share amounts may not agree with year-to-date basic and diluted earnings (loss) per share amounts as a result of each period's computation being based on the weighted average number of common shares outstanding during that period.

	Three Months Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
	(in thousands, except per share data)			
Year ended December 31, 2009				
Oil and gas revenues	$ 12,300	$ 16,829	$ 19,980	$ 22,509
Other revenues [1]	2,160	2,398	2,980	852
Operating expenses [2]	(10,713)	(10,313)	(13,286)	(14,696)
Operating income	3,747	8,914	9,674	8,665
Other income (expense), net [3]	(2,910)	(3,199)	(3,706)	(6,343)
Income tax (expense) benefit	(360)	(2,216)	(2,540)	49
Net income	$ 477	$ 3,499	$ 3,428	$ 2,371
Basic net income per share	$ 0.03	$ 0.22	$ 0.21	$ 0.14
Diluted net income per share	$ 0.03	$ 0.22	$ 0.21	$ 0.14

	Three Months Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
	(in thousands, except per share data)			
Year ended December 31, 2008				
Oil and gas revenues	$ 22,463	$ 25,118	$ 21,763	$ 15,919
Other revenues [1]	1,261	2,859	1,640	2,818
Operating expenses [2]	(12,255)	(13,276)	(12,193)	(14,824)
Operating income	11,469	14,701	11,210	3,913
Other income (expense), net [3]	(4,649)	(2,365)	(1,583)	(11,405)
Income tax (expense) benefit	(2,596)	(4,546)	(3,828)	3,201
Net income (loss)	$ 4,224	$ 7,790	$ 5,799	$ (4,291)
Basic net income (loss) per share	$ 0.29	$ 0.51	$ 0.36	$ (0.26)
Diluted net income (loss) per share	$ 0.29	$ 0.50	$ 0.35	$ (0.26)

(1) Partnership management fees, property operating income, gain (loss) on sale of property and partnership income.
(2) Lease operating expense, production taxes, re-engineering & workover, exploration, and depreciation depletion and amortization.
(3) Other income (expense), net for the second and fourth quarters of 2009 included impairment expenses of $128,000 and $2,667,000, respectively. For the fourth quarter of 2008, Other income (expense) included impairment expense of $8,339,000.

NOTE O: Supplemental Financial Information for Oil and Gas Producing Activities (Unaudited)

1. Costs Incurred Related to Oil and Gas Activities

The Company's oil and gas activities for 2009, 2008 and 2007 were entirely within the United States. Costs incurred in oil and gas producing activities were as follows:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Acquisition cost	$ 66,594	$ 33,946	$ 151,607
Development cost	$ 23,623	$ 16,974	$ 3,618
Exploration cost	$ 1,406	$ 2,592	$ 153

During 2009, 2008 and 2007, additions to oil and gas properties of $262,000, $158,000 and $5,681,000 were recorded for estimated costs of future abandonment related to new wells drilled or acquired. The 2007 additions included the additions related to the reverse merger.

	December 31,	
	2009	2008
	(in thousands)	
Proved properties	$ 285,363	$ 204,536
Unproved properties	10,281	2,409
	295,644	206,945
Accumulated depreciation, depletion and amortization	(47,731)	(26,218)
Net capitalized cost	$ 247,913	$ 180,727

The amounts included in unproved properties are projects for which the Company intends to commence exploration or evaluation projects in the near future. Of the approximately $10.3 million in net unevaluated property costs at December 31, 2009, that are being excluded from the amortizable base, approximately $7.9 million was incurred in 2008, $1.3 million was incurred in 2007 and $1.0 million was incurred in 2006. The Company will begin to amortize these costs when proved reserves are established or an impairment is determined.

2. Estimated Quantities of Proved Oil and Gas Reserves

For all years presented, the estimate of proved reserves and related valuations were based 100% on reports prepared by the Company's independent petroleum engineers. The reports were prepared by Cawley, Gillespie & Associates, Inc. Proved reserve estimates included herein conform to the definitions prescribed by the U.S. Securities and Exchange Commission. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Proved reserves are estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under economic and operating conditions existing as of the end of each respective year. Proved developed reserves are those which are expected to be recovered through existing wells with existing equipment and operating methods.

Presented below is a summary of the changes in estimated proved reserves of the Company, all of which are located in the United States, for the years ended December 31, 2009, 2008 and 2007:

Oil and Gas Reserve Quantities (in thousands):

	Oil (MBbl)	Gas (MMcf)
Proved reserve quantities, December 31, 2006	1,777	4,218
Purchase of minerals-in-place	9,080	27,977
Extension and discoveries	7	965
Production	(391)	(1,648)
Revision of quantity estimates	271	(1,702)
Proved reserve quantities, December 31, 2007	10,744	29,810
Purchase of minerals-in-place	672	9,726
Sales of minerals-in-place	(988)	(4,946)
Extensions and discoveries	501	1,155
Production	(743)	(2,962)
Revisions of quantity estimates	(1,393)	2,013
Proved reserve quantities, December 31, 2008	8,793	34,796
Purchase of minerals-in-place	586	25,728
Sales of minerals-in-place	(59)	(80)
Extensions and discoveries	972	9,227
Production	(851)	(4,944)
Revisions of quantity estimates*	1,978	(9,291)
Proved reserve quantities, December 31, 2009	11,419	55,436
Proved developed reserve quantities:		
December 31, 2007	8,921	26,427
December 31, 2008	7,522	25,025
December 31, 2009	9,221	38,138
Proved undeveloped reserve quantities:		
December 31, 2007	1,823	3,383
December 31, 2008	1,271	9,771
December 31, 2009	2,198	17,298

Notable changes in proved reserves for the year ended December 31, 2009 included:

* Revisions to previous estimates. The revision increase in estimated oil quantities related to price increases was 2,204,000 Bbls, which was partially offset by reductions of 1,030,000 Bbls due to a change in pricing method as prescribed by the SEC. Other increases of 804,000 Bbls accounted for the remainder of the total positive revision of 1,978,000 Bbls. The revision decrease in estimated gas quantities related to price increases was 960,000 Mcf, offset by a decrease of 10,572,000 Mcf attributable to the change in pricing methods prescribed by the SEC. Other increases in gas reserves of 321,000 Mcf accounted for the remainder of the negative revision of 9,291,000 Mcf. The change in pricing method prescribed by the SEC is from the use of a year-end price to the use of a 12-month average price, which is discussed in Note A, Recently Issued Accounting Pronouncements.

3. *Discounted Future Net Cash Flows*

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with FASB ASC topic *Extractive Activities – Oil and Gas*. Future cash inflows as of December 31, 2009, were computed by applying average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2009) to estimated future production. Future cash inflows as of December 31, 2008 and 2007, however, were computed by applying prices at year-end to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on year-end costs and assuming the continuation of existing economic conditions.

Future income tax expense is calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of the properties involved. Future income tax expense gives effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

Presented below is the standardized measure of discounted future net cash flows as of December 31, 2009, 2008 and 2007.

Standardized Measure of Estimated Future Net Cash Flows

	December 31, 2009	December 31, 2008	December 31, 2007
		(in thousands)	
Future cash inflows	$ 789,647	$ 547,966	$ 1,171,932
Future production costs	316,815	228,369	418,750
Future development costs	64,560	35,020	49,036
Future income taxes	83,182	56,860	191,598
Future net cash flows	325,090	227,717	512,548
10% annual discount for estimated timing of cash flows	150,990	107,098	233,902
Standardized measure of discounted future cash flows	$ 174,100	$ 120,619	$ 278,646

Future cash flows as shown above are reported without consideration for the effects of open hedge contracts at each period end. If the effects of hedging transaction were included in the computation, then undiscounted future cash flows would have decreased by $4.3 million in 2009, increased by $14.6 million in 2008, and decreased by $21 million in 2007.

The principal sources of changes in the standardized measure of discounted future net cash flows for 2009, 2008 and 2007 are as follows:

Changes in Standardized Measure

	Year Ended December 31,		
	2009 *	2008	2007
	(in thousands, except product prices)		
Standardized measure, beginning of period	$ 120,619	$ 278,646	$ 40,318
Changes in prices, net of production cost	47,246	(206,127)	26,229
Extensions, discoveries and enhanced production	20,989	6,571	3,183
Revision of quantity estimates	14,876	(4,221)	815
Development costs incurred, previously estimated	7,045	876	1,366
Change in estimated future development costs	(17,629)	9,676	105
Purchases of minerals-in-place	36,002	17,401	325,882
Sales of minerals-in-place	(786)	(39,923)	-
Sale of oil and gas produced, net of production costs	(53,860)	(61,283)	(20,462)
Accretion of discount	16,663	43,861	4,171
Change in estimated future income taxes	(13,495)	73,348	(103,258)
Changes in timing of estimated cash flows and other	(3,570)	1,794	297
	$ 174,100	$ 120,619	$ 278,646
Prices, used in standardized measure:			
Oil (per barrel)	$ 61.18	$ 41.47	$ 89.88
Gas (per Mcf)	$ 3.83	$ 5.29	$ 6.87

* In 2009, standardized measure was reduced by $90,025,000 due to the use of a 12-month average price as prescribed by the new reserve rules (discussed in Note A Recently Issued Accounting Pronouncements) versus an end of the year price. Had the Company not changed its pricing method to comply with the SEC's new rules the standardized measure at December 31, 2009 would have been $264,124,000.

Equity in Partnership Reserves

1. *Costs Incurred Related to Oil and Gas Activities*

The following two unaudited tables set forth the Company's share of costs incurred in the affiliated partnerships during the years ended December 31, 2009, 2008, and 2007. During 2007, the Company held an interest in only one of the affiliated partnership versus two in 2008 and 2009 that were accounted for using the equity method. Furthermore, during 2009, the Company's interest in one of the partnerships, SBE Partners, increased significantly from 2% to 30%. For further information see note M above.

Costs incurred in acquisition, development and exploration:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Acquisition cost	$ 346	$ 949	$ 1,553
Development cost	$ 771	$ 633	$ 434
Exploration cost	$ -	$ -	$ -

Capitalized cost of oil and gas properties:

	December 31,	
	2009	2008
	(in thousands)	
Proved properties	$ 4,474	$ 3,543
Unproved properties	-	-
	4,474	3,543
Accumulated depreciation, depletion and amortization	(1,344)	(662)
Net capitalized cost	$ 3,130	$ 2,881

2. *Estimated Quantities of Proved Oil and Gas Reserves and Discounted Future Net Cash Flows*

The reserve information presented above does not include the Company's share of reserves held by two limited partnerships which are accounted for under the equity method of accounting. The following table presents the Company's estimated share of the oil and gas reserves held by both limited partnerships as of December 31, 2009 and 2008. The table also includes the Company's estimated share of oil and gas reserves for SBE Partners as of December 31, 2007.

	Year Ended December 31,					
	2009		2008		2007	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
Oil and gas volumes:						
Proved developed	45	7,821	58	12,227	5	876
Proved undeveloped	10	613	61	4,510	3	248
Total	55	8,434	119	16,737	8	1,124

Presented below is a summary of the changes in estimated proved reserves of the Company's equity investments, all of which are located in the United States, for the years ended December 31, 2009:

Oil and Gas Reserve Quantities (in thousands):

	Oil (MBbl)	Gas (MMcf)
Proved reserve quantities, January 1, 2009	119	16,737
Sales of minerals-in-place	(50)	(6,618)
Extension and discoveries	1	128
Production	(3)	(975)
Revision of quantity estimates	(12)	(838)
Proved reserve quantities, December 31, 2009	55	8,434
Proved developed reserve quantities:		
December 31, 2009	45	7,821
Proved undeveloped reserve quantities:		
December 31, 2009	10	613

Presented below is the Company's share of standardized measure of discounted future net cash flows as of December 31, 2009 for its equity investments:

Standardized Measure of Estimated Future Net Cash Flows (in thousands):

Future cash inflows	$	29,083
Future production costs		10,339
Future development costs		1,893
Future income taxes		5,177
Future net cash flows		11,674
10% annual discount for estimated timing of cash flows		4,339
Standardized measure of discounted future cash flows	$	7,335

The principal sources of change in the Company's share of standardized measure of discounted future net cash flows for the Company's equity investments for 2009 are as follows:

Changes in Standardized Measure

Standardized measure, beginning of period	$	17,871
Changes in prices, net of production cost		(12,609)
Extensions, discoveries and enhanced production		77
Revision of quantity estimates		(776)
Development costs incurred, previously estimated		641
Change in estimated future development costs		(550)
Purchases of minerals-in-place		-
Sales of minerals-in-place		(7,273)
Sale of oil and gas produced, net of production costs		(2,358)
Accretion of discount		2,599
Change in estimated future income taxes		649
Changes in timing of estimated cash flows and other		9,064
	$	7,335
Current prices at year-end, used in standardized measure:		
Oil (per barrel)	$	61.18
Gas (per Mcf)	$	3.83

Signatures

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the Registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GEORESOURCES, INC. (the "Registrant)

Dated: March 12, 2010

/s/ Frank A. Lodzinski

Frank A. Lodzinski, Chief Executive Officer

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

(Power of Attorney)

Each person whose signature below constitutes and appoints FRANK A. LODZINSKI and HOWARD E. EHLER his true and lawful attorneys-in-fact and agents, each acting along, with full power of stead, in any and all capacities, to sign any or all amendments to this annual report on Form 10-K for the year ended December 31, 2009, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, each acting alone, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in each acting alone, or his substitute or substitutes, may lawfully do or cause to be done by virtue thereof.

Signatures	Title	Date
/s/ Frank A. Lodzinski Frank A. Lodzinski	President, Chief Executive Officer (principal executive officer) and Director	March 12, 2010
/s/ Howard E. Ehler Howard E. Ehler	Principal Financial Officer and Principal Accounting Officer	March 12, 2010
/s/ Collis P. Chandler, III Collis P. Chandler, III	Director	March 12, 2010
/s/ Christopher W. Hunt Christopher W. Hunt	Director	March 12, 2010
/s/ Jay F. Joliat Jay F. Joliat	Director	March 12, 2010
/s/ Scott R. Stevens Scott R. Stevens	Director	March 12, 2010
/s/ Nicholas L. Voller Nicholas L. Voller	Director	March 12, 2010
/s/ Michael A. Vlasic Michael A. Vlasic	Director	March 12, 2010

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 12, 2010, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of GeoResources, Inc. on Form 10-K for the year ended December 31, 2009. We hereby consent to the incorporation by reference of said reports in the Registration Statements of GeoResources, Inc. on Forms S-1 initially filed on Forms S-3 and amended on Forms S-1 by post-effective amendments (File No. 333-144831, effective August 13, 2007; File No. 333-152041, effective July 10, 2008; and File No. 333-155681, effective February 5, 2009) and on Forms S-8 (File No. 333-145221, effective August 8, 2007 and File No. 333-149216, effective February 13, 2008).

/s/ Grant Thornton LLP
Houston, Texas
March 12, 2010

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 12, 2010, with respect to the financial statements of SBE Partners LP included in the Annual Report of GeoResources, Inc. on Form 10-K for the year ended December 31, 2009. We hereby consent to the incorporation by reference of said report in the Registration Statements of GeoResources, Inc. on Forms S-1 initially filed on Forms S-3 and amended on Forms S-1 by post-effective amendments (File No. 333-144831, effective August 13, 2007; File No. 333-152041, effective July 10, 2008; and File No. 333-155681, effective February 5, 2009) and on Forms S-8 (File No. 333-145221, effective August 8, 2007 and File No. 333-149216, effective February 13, 2008).

/s/ Grant Thornton LLP
Houston, Texas
March 12, 2010

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to references to our firms in the form and context in which they appear in the Annual Report on Form 10-K of GeoResources, Inc. for the year ended December 31, 2009. We hereby further consent to the use of information contained in our reports setting forth the estimates of revenues from GeoResources' oil and gas reserves as of December 31, 2009, 2008, and 2007 and to the inclusion of our report dated February 22, 2010, as an exhibit to the Annual Report on Form 10-K of GeoResources, Inc. for the year ended December 31, 2009.

Sincerely,

/s/ Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693
March 10, 2010

EXHIBIT 31.1

CERTIFICATION

I, Frank A. Lodzinski, certify that:

1. I have reviewed this Annual Report on Form 10-K of GeoResources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Frank A. Lodzinski

Frank A. Lodzinski
Chief Executive Officer
March 12, 2010

EXHIBIT 31.2

CERTIFICATION

I, Howard E. Ehler, certify that:

1. I have reviewed this Annual Report on Form 10-K of GeoResources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Howard E. Ehler

Howard E. Ehler
Chief Financial Officer
March 12, 2010

EXHIBIT 32.1

CERTIFICATION

I, Frank A. Lodzinski, certify that:

In connection with the Annual Report on Form 10-K of GeoResources, Inc. (the "**Company**") for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "**Report**"), I, Frank A. Lodzinski, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Frank A. Lodzinski

Frank A. Lodzinski
Chief Executive Officer
March 12, 2010

EXHIBIT 32.2

CERTIFICATION

I, Howard E. Ehler, certify that:

In connection with the Annual Report on Form 10-K of GeoResources, Inc. (the "**Company**") for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "**Report**"), I, Howard E. Ehler, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Howard E. Ehler

Howard E. Ehler
Chief Financial Officer
March 12, 2010

Shareholder Information

Officers & Directors

Frank A. Lodzinski
President, Chief Executive Officer & Chairman

Collis P. Chandler, III
EVP, Chief Operating Officer - Northern Region & Director

Francis M. Mury
EVP, Chief Operating Officer - Southern Region

Robert J. Anderson
VP, Business Development,
Acquisitions & Divestitures

Howard E. Ehler
VP, Chief Financial Officer

Independent Directors

Jay F. Joliat
Joliat Enterprises, LLC

Bryant W. Seaman, III
Bessemer Trust

Michael A. Vlasic
Vlasic Investments, LLC

Nicholas L. Voller
Voller, Lee & Suess, P.C., CPAs

Donald J. Whelley
DJW Advisors, LLC

Investor Relations

Financial analysts, investors and shareholders desiring information about GeoResources, Inc. should write to Cathy Kruse, Investor Relations, P. O. Box 1505, Williston, ND 58802 or call 701-572-2020 x113. Information may also be obtained by visiting the company's website.

Independent Reservoir Engineers

Cawley, Gillespie & Associates, Inc.

Auditors

Grant Thornton LLP

Legal Counsel

Jones & Keller

Website

www.georesourcesinc.com

Corporate and Regional Offices

GeoResources, Inc.
110 Cypress Station Dr., Suite 220
Houston, TX 77090-1629
Tel: 281-537-9920
Fax: 281-537-8324

Southern Region
Southern Bay Energy, LLC
110 Cypress Station Dr., Suite 220
Houston, TX 77090-1629
Tel: 281-537-9920
Fax: 281-537-8324

Northern Region
G3 Energy, LLC
475 17th St., Suite 1210
Denver, CO 80202
Tel: 303-297-2028
Fax: 303-297-2196

Williston Basin
G3 Operating, LLC
1407 W. Dakota Pky, Suite 1
Williston, ND 58801
Tel: 701-572-2020
Fax: 701-572-0277

Transfer Agent

Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
Tel: 800-468-9716
website: www.wellsfargo.com/shareownerservices

Stock Traded

GeoResources, Inc. common stock trades on the NASDAQ Global Market under the symbol GEOI.

Forward-Looking Information

Information herein contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by words such as "may," "expect," "anticipate," "estimate," or "continue," or comparable words. In addition, all statements other than statements of historical facts that address activities that the Company expects or anticipates will or may occur in the future are forward-looking statements. Readers are encouraged to read the SEC reports of the Company, particularly its Form 10-K for the Fiscal Year Ended December 31, 2009, for meaningful cautionary language disclosure.

GeoResources, Inc.

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