FORM 10-Q

Quarterly report pursuant to sections 13 or 15(d)

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GEORESOURCES INC

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SIC: **1311** Crude petroleum & natural gas

Mailing Address
110 CYPRESS STATION DRIVE
SUITE 220
HOUSTON TX 77090-1629

Business Address
110 CYPRESS STATION DRIVE
SUITE 220
HOUSTON TX 77090-1629
2815379920

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the Quarterly Period ended September 30, 2011

Commission File Number – 0-8041

GeoResources, Inc.

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

Colorado	**84-0505444**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
110 Cypress Station Drive, Suite 220 Houston, Texas	**77090-1629**
(Address of principal executive offices)	**(Zip code)**

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

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 registration was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Larger accelerated filer ☐ Accelerated filer ☒

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 ☒

Indicate the number of shares outstanding of each of the issuer' s classes of common stock, as of the latest practicable date.

Class of equity	Outstanding at November 4, 2011
Common stock, par value $.01 per share	25,578,980 shares

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GEORESOURCES, INC and SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	September 30, 2011 (unaudited)	December 31, 2010
ASSETS		
Current assets:		
Cash	$35,746	$9,370
Accounts receivable:		
Oil and gas revenues	22,850	17,017
Joint interest billings and other	23,313	16,631
Affiliated partnerships	626	969
Notes receivable	537	120
Derivative financial instruments	8,106	4,282
Income taxes receivable	2,447	222
Prepaid expenses and other	3,271	2,645
Total current assets	96,896	51,256
Oil and gas properties, successful efforts method:		
Proved properties	404,611	341,582
Unproved properties	48,014	32,403
Office and other equipment	1,505	1,140
Land	146	146
	454,276	375,271
Less accumulated depreciation, depletion and amortization	(88,416)	(72,380)
Net property and equipment	365,860	302,891
Equity in oil and gas limited partnerships	2,696	2,272
Derivative financial instruments	4,049	851
Deferred financing costs and other	1,477	2,420
	$470,978	$359,690

The accompanying notes are an integral part of these statements.

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

	September 30, 2011	December 31, 2010
	(unaudited)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 14,286	$ 14,616
Accounts payable to affiliated partnerships	3,694	2,931
Revenue and royalties payable	15,769	12,450
Drilling advances	19,266	4,203
Accrued expenses	3,702	1,331
Derivative financial instruments	–	7,433
Total current liabilities	56,717	42,964
Long-term debt	–	87,000
Deferred income taxes	40,285	19,289
Asset retirement obligations	7,155	7,052
Derivative financial instruments	–	1,650
Stockholders' equity:		
Common stock, par value $0.01 per share; authorized 100,000,000 shares; issued and outstanding: 25,571,480 in 2011 and 19,726,566 in 2010	256	197
Additional paid-in capital	280,510	148,172
Accumulated other comprehensive income	7,328	(3,000)
Retained earnings	78,727	54,133
Total GeoResources, Inc. stockholders' equity	366,821	199,502
Noncontrolling interest	–	2,233
Total equity	366,821	201,735
	$ 470,978	$ 359,690

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)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenue:				
Oil and gas revenues	$35,229	$25,612	$91,135	$74,684
Partnership management fees	127	124	369	423
Property operating income	840	498	2,201	1,282
Gain on sale of property and equipment	207	243	944	388
Partnership income	634	429	1,549	1,771
Interest and other	65	23	423	1,363
Total revenue	37,102	26,929	96,621	79,911
Expenses:				
Lease operating expense	6,813	5,146	17,579	15,363
Production taxes	2,367	1,520	5,886	4,843
Re-engineering and workovers	1,033	881	2,136	1,389
Exploration expense	278	163	634	766
Impairment of oil and gas properties	–	–	–	2,743
General and administrative expense	3,144	2,023	8,706	5,881
Depreciation, depletion and amortization	7,391	6,204	19,319	18,517
Hedge ineffectiveness	(103)	(656)	538	(976)
Interest	482	1,391	1,520	3,949
Total expense	21,405	16,672	56,318	52,475
Income before income taxes	15,697	10,257	40,303	27,436
Income tax expense (benefit):				
Current	316	8,834	1,114	10,699
Deferred	5,966	(6,213)	14,682	(1,416)
	6,282	2,621	15,796	9,283
Net income	$9,415	$7,636	$24,507	$18,153
Less: Net loss attributable to noncontrolling interest	–	–	(87)	–
Net income attributable to GeoResources, Inc.	$9,415	$7,636	$24,594	$18,153
Net income per share (basic)	$0.37	$0.39	$0.98	$0.92
Net income per share (diluted)	$0.36	$0.38	$0.96	$0.90
Weighted average shares outstanding:				
Basic	25,475,532	19,723,916	25,034,199	19,719,120
Diluted	25,844,758	20,080,670	25,486,593	20,076,472

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC. and SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY and COMPREHENSIVE INCOME
Nine Months Ended September 30, 2011
(In thousands, except share data)
(unaudited)

	Common Stock		Additional		Accumulated	Non-	
			Paid-in	Retained	Other Comprehensive	Controlling	
	Shares	Par value	Capital	Earnings	Income (Loss)	Interest	Total
Balance, December 31, 2010	19,726,566	$ 197	$148,172	$54,133	$ (3,000)	$2,233	$201,735
Issuance of common stock for cash, net of issuance costs of $6,889	5,175,000	52	122,434				122,486
Exercise of employee stock options	669,914	7	6,040				6,047
Excess tax benefit from share-based compensation			2,398				2,398
Comprehensive income:							
Net income				24,594		(87)	24,507
Change in fair market value of hedged positions, net of taxes of $5,569					9,115		9,115
Hedging gains realized in income, net of taxes of $746					1,213		1,213
Total comprehensive income							34,835
Equity based compensation expense			1,466				1,466
Deconsolidation of noncontrolling interest						(2,146)	(2,146)
Balance, September 30, 2011	25,571,480	$ 256	$280,510	$78,727	$ 7,328	$−	$366,821

The accompanying notes are an integral part of this statement.

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GEORESOURCES, INC. and SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(unaudited)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Cash flows from operating activities:		
Net income	$ 24,507	$ 18,153
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	19,319	18,517
Proved property impairments	–	2,743
Gain on sale of property and equipment	(944)	(388)
Accretion of asset retirement obligations	336	300
Unrealized gain on derivative contracts	–	(305)
Hedge ineffectiveness (gain) loss	538	(974)
Partnership income	(1,549)	(1,771)
Partnership distributions	1,126	2,919
Deferred income taxes	14,682	(1,416)
Non-cash compensation	1,466	793
Excess tax benefit from share-based compensation	(2,398)	–
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(12,262)	10,285
(Increase) decrease in prepaid expense and other	250	988
(Decrease) increase in accounts payable and accrued expense	18,434	(804)
(Decrease) increase in revenues and royalties payable	3,528	(930)
Net cash provided by operating activities	67,033	48,110
Cash flows from investing activities:		
Proceeds from sale of property and equipment	411	540
Additions to property and equipment, net of acreage cost recoveries of none in 2011 and recoveries of $20,230 in 2010	(84,999)	(65,282)
Net cash used in investing activities	(84,588)	(64,742)
Cash flows from financing activities:		
Proceeds from stock options exercised	6,047	103
Issuance of common stock	122,486	–
Excess tax benefit from share-based compensation	2,398	–
Issuance of long-term debt	–	16,000
Reduction of long-term debt	(87,000)	–
Net cash provided by financing activities	43,931	16,103
Net increase (decrease) in cash and cash equivalents	26,376	(529)
Cash and cash equivalents at beginning of period	9,370	12,660
Cash and cash equivalents at end of period	$ 35,746	$ 12,131
Supplementary information:		
Interest paid	$ 696	$ 3,161
Income taxes paid	$ 998	$ 2,629
Non-cash investing activities		
Accounts receivable–acreage cost recoveries	$ –	$ 20,000

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC. and SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

NOTE A: Organization and Basis of Presentation

Description of Operations

GeoResources, Inc. 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.

Consolidated Financial Statements

The unaudited consolidated financial statements include the accounts of GeoResources, Inc. ("GeoResources" or the "Company") and its majority-owned subsidiaries. We consolidated our non-controlling interest in Trigon LLC ("Trigon") until September 2011, at which time we deconsolidated the non-controlling interest due to a distribution of all of Trigon' s assets to Trigon' s owners. The financial statements have been prepared in accordance with U.S. generally accepted accounting principles for interim financial reporting. All intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, the accompanying financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company' s interim results. GeoResources' 2010 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in GeoResources' 2010 Annual Report on Form 10-K. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Earnings Per Share

Basic earnings per share is computed by dividing net income attributable to common shares by the basic weighted-average shares of common stock outstanding during the period. The calculation of diluted earnings per share is similar to basic, except the denominator includes the effect of dilutive common stock equivalents. Dilutive common stock equivalents consist of unvested restricted stock unit awards and outstanding stock options. The number of potential common shares outstanding relating to stock options and restricted stock units is computed using the treasury stock method. Net income per share computations reconciling basic and diluted net income for the three and nine months ended September 30, 2011 and 2010 consist of the following (in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Numerator:				
Net income attributable to common shares	$9,415	$7,636	$24,594	$18,153
Denominator:				
Basic weighted average shares	25,476	19,724	25,034	19,719
Effect of dilutive securities−share-based compensation	369	357	453	357
Diluted weighted average shares	25,845	20,081	25,487	20,076
Earnings per share				
Basic	$0.37	$0.39	$0.98	$0.92
Diluted	$0.36	$0.38	$0.96	$0.90

For the three month periods ended September 30, 2011 and 2010, options to purchase 16,400 and 71,477 shares of common stock, respectively, were excluded from the dilutive earnings per share calculation because the effect would have been anti-dilutive. For the nine month periods ended September 30, 2011 and 2010, options to purchase 4,600 and 70,543 shares of common stock, respectively, were excluded from the dilutive earnings per share calculation because the effect would be anti-dilutive.

For the three and nine month period ended September 30, 2011, approximately 5,900 and 6,200 restricted stock units, respectively, were excluded from the dilutive earnings per share calculation because their effect would be anti-dilutive.

For the three and nine month period ended September 30, 2011 and 2010, warrants to purchase 613,336 shares of common stock were excluded from the dilutive earnings per share calculation because the warrants' exercise price exceeded the average market price of the Company's common shares during these periods.

NOTE B: Acquisitions and Dispositions

In August 2011, the Company closed an acquisition of producing oil and gas properties located in the Austin Chalk trend of East Texas. The purchase price was $11 million plus closing adjustments for normal operating activity. The acquisition included approximately 3,700 net acres. For the three and nine months ended September 30, 2011, these properties contributed $570,000 of revenue to the Company.

In November 2010, the Company purchased an 86.67% membership interest in Trigon Energy Partners LLC ("Trigon") which held leases in the Eagle Ford shale trend of Texas and recorded a $2.2 million non-controlling interest in the Company's financial statements. The acquisition cost was approximately $11.8 million. In June 2011, the Company's membership interest decreased to 73.34% as a result of a $2.2 million capital contribution by the non-controlling interest holder. In September 2011, we deconsolidated the non-controlling interest in the financial statements due to a distribution of all of Trigon's assets to Trigon's owners.

In September 2010, the Company entered into an agreement with an unaffiliated third party to jointly acquire and develop mineral leases in the Eagle Ford shale trend of Texas. As part of this agreement, the Company sold a 50% working interest in approximately 20,000 acres for $20 million. For accounting purposes, the Company uses the cost recovery method; under this method proceeds from joint owners are recorded in the balance sheet as a reduction of the carrying value of unproved properties. The purchaser also agreed to pay 100% of the drilling costs for the first six wells to be drilled in a contractually specified area of mutual interest ("AMI"). The agreement also provides for an additional $20 million for additional joint leasing within the AMI ($10 million net to each entity). Subsequent to the initial closing, the Company and the joint owners have continued to acquire leases within the AMI pursuant to the terms of the agreement.

In July 2010, the Company closed an acquisition of producing oil and gas properties located in the Giddings field of central Texas. The purchase price was $16.6 million plus closing adjustments for normal operating activity. The acquisition included approximately 9,700 net acres and was funded through borrowings under the Company's credit facility.

NOTE C: Recently Issued Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income. This update will require the presentation of the components of net income and other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In addition, companies are also required to present reclassification adjustments for items that are reclassified from other comprehensive income to net income on the face of the financial statements. The update is effective for fiscal years and interim periods beginning after December 15, 2011. The Company will adopt the new disclosure requirements for comprehensive income beginning January 1, 2012.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. This ASU issued authoritative guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. The ASU expands existing disclosure requirements for fair value measurements categorized in Level 3 by requiring (1) a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, (2) a description of the valuation processes in place, and (3) a narrative description of the sensitivity of the fair value to changes in unobservable inputs and the interrelationships between those inputs. Entities will also be required to disclose the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed.

Other amendments include clarifying the highest and best use and valuation premise for nonfinancial assets, premiums and discounts in fair value measurement, and fair value of an instrument classified in a reporting entity' s shareholders' equity.

ASU 2011-04 is effective during interim and annual periods beginning after December 15, 2011, and therefore will become effective for the Company on January 1, 2012 for the quarter ending March 31, 2012. Other than the disclosure requirements, ASU 2011-04 is not expected to have a significant impact on the Company' s consolidated financial statements.

NOTE D: Long-term debt

The Company has a $250 million credit facility with a borrowing base at September 30, 2011 of $145 million. The credit facility provides for annual interest rates at (a) LIBOR plus 2.25% to 3.00% or (b) the prime rate plus 1.25% to 2.00%, depending upon the amount borrowed. The credit facility also requires the payment of commitment fees to the lender on the unutilized commitment. 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 credit facility, and guarantees of those obligations, are secured by substantially all of the Company' s assets.

The credit facility 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 September 30, 2011.

The Company has no principal outstanding under its credit facility at September 30, 2011. In the first quarter of 2011, the Company used certain net proceeds from the public offering of its common stock, discussed in Note I, to pay its outstanding indebtedness under the credit facility. The principal outstanding under the Company' s credit facility was $87 million at December 31, 2010. The maturity date for amounts outstanding under the Second Amended and Restated Credit Agreement is October 16, 2012.

Interest expense for the three months ended September 30, 2011 and 2010 includes amortization of deferred financing costs of $272,000 and $265,000, respectively. Interest expense for the nine months ended September 30, 2011 and 2010 includes amortization of deferred financing costs of $805,000 and $793,000, respectively.

In connection with the initial borrowing from the bank under the credit facility the Company entered into an interest rate swap. The purpose was to protect the Company from undue exposure to interest rate increases. The swap agreement provided 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 rate of 4.29%. The $40 million swap was accounted for as a cash flow hedge while the $10 million swap was marked-to-market with gains and losses included in the Company' s Consolidated Statement of Income. These swaps expired in October 2010.

For the three and nine months ended September 30, 2010, the Company recognized realized cash settlement losses of $408,000 and $1.2 million, respectively, related to the $40 million swap designated as a cash flow hedge.

NOTE E: 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. In June 2011, the shareholders of the Company approved an amendment to the Plan which increased the number of authorized issuances of stock-based incentives to 3,250,000 shares. The amendment also allows the issuance of performance units, including restricted stock units.

The options granted under the Plan can be designated as either incentive options or nonqualified options. The following is a summary of the terms of the June 2011 option grants by exercise price:

	Number of Shares Exercisable at:	
Vesting Date	$ 23.00	$ 27.00
Director		
June 6, 2012	5,000	5,000
June 6, 2013	5,000	5,000
June 6, 2014	5,000	5,000
June 6, 2015	5,000	5,000
	20,000	20,000

The closing market price of the Company' s common stock on the date of the June 2011 option grants was $21.57.

The weighted-average fair value of the options granted during the nine months ended September 30, 2011, was $11.50 per share, using the following assumptions:

	June 7, 2011 Grant	
Risk-free interest rate	1.58	%
Dividend yield	None	
Volatility	67	%
Weighted average expected life of options	5.00	
Estimated forfeiture rate	1	%

A summary of the Company' s stock option activity for the nine months ended September 30, 2011 is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Fair Value	Weighted Average Remaining Contractual Life (year)	Aggregate Intrinsic Value
Outstanding, December 31, 2010	1,494,350	$9.70	$3.49	7.34	$18,701,164
Granted	40,000	$25.00	$11.50		$–
Exercised	(678,414)	$9.28	$2.94		$11,780,546
Canceled/forfeited	(50,000)	$9.41	$3.22		$806,750
Outstanding, September 30, 2011	805,936	$10.83	$4.38	7.16	$5,942,466
Vested and exercisable	239,686	$9.41	$3.71	6.84	$2,021,441
Vested and expected to vest	801,573	$10.81	$4.36	7.15	$5,920,244

During the nine months ended September 30, 2011, 175,000 options vested with a weighted average exercise price of $10.15. The weighted average grant date fair value of these options was $4.81 per option. At September 30, 2011, there were 566,250 unvested options with a weighted average remaining amortization period of 2.04 years.

The Company recognizes compensation expense by first calculating the fair value of the options at the date of grant determined by the Black-Scholes option pricing model. The Company then amortizes the value of these options as compensation expense on a straight line basis over the vesting period of the options. For the quarters ended September 30, 2011 and 2010 the Company recognized compensation expense of $211,000 and $299,000, respectively, related to these options. For the nine month periods ended September 30, 2011 and 2010, the Company recognized compensation expense of $773,000 and $793,000, respectively, related to these options. As of September 30, 2011, the future un-amortized pre-tax compensation expense associated with non-vested stock options totaled $1.7 million to be recognized through the second quarter of 2015.

In addition to the stock option grants discussed above, during 2011, the Company granted certain officers, employees and directors 191,050 restricted stock units. Each restricted stock unit represents a contingent right to receive one share of the Company' s common stock upon vesting. Compensation expense, determined by multiplying the number of restricted stock units granted by the closing market price of the Company' s stock on the grant date, is recognized over the respective vesting periods on a straight-line basis. For the three and nine months ended September 30, 2011, compensation expense related to restricted stock units was $445,000 and $693,000, respectively. The Company has an assumed forfeiture rate of 1% on restricted stock issued. As of September 30, 2011, the future unamortized pre-tax compensation expense associated with unvested restricted stock units totaled approximately $4.6 million to be recognized through July 2014. The weighted average vesting period related to unvested restricted stock units at September 30, 2011 was approximately 2.6 years.

A summary of the Company' s restricted stock unit activity for the nine months ended September 30, 2011 is as follows

	Shares	Fair Values (1)
Outstanding, December 31, 2010	–	–
Granted	191,050	$ 27.76
Vested	–	–
Forfeited	–	–
Outstanding, September 30, 2011	191,050	$ 27.76

(1) Represents the weighted average grant date market value

The Company has 613,336 outstanding warrants to purchase common stock outstanding at September 30, 2011. The warrants, which were acquired by non-affiliated accredited investors as part of the June 5, 2008 private placement offering, have an exercise price of $32.43 and have a remaining life of 1 year and 8 months.

NOTE F: Income Taxes

Deferred income taxes are recorded to account for the tax effects associated with 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 amounts are measured using the enacted tax rates applicable to periods when these differences are expected to reverse.

Uncertain Tax Positions

The Company will consider a tax position settled if the taxing authority has completed its examinations, the Company does not plan to appeal the tax authority ruling, and the Company deems the possibility that the taxing authority will reexamine the tax position in the future as remote. For uncertain tax issues, 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 September 30, 2011, 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 as of September 30, 2011.

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

It is also the Company' s practice 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 Statements of Income. As of September 30, 2011, the Company did not have any accrued interest or penalties associated with any unrecognized 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 September 30, 2012.

NOTE G: 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 may also limit future revenues from favorable price movements.

At September 30, 2011, accumulated other comprehensive income (loss) consisted of unrecognized gains of $7.3 million, net of taxes of $4.5 million, 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. At December 31, 2010, accumulated other comprehensive income (loss) consisted of unrecognized losses of $3.0 million, net of taxes of $1.8 million. For the three and nine months ended September 30, 2011, the Company recognized realized cash settlement gains of $551,000 and losses of $2.0 million, respectively. For the three and nine months ended September 30, 2010, the Company recognized net realized cash settlement gains on commodity derivatives of $2.0 million and $3.2 million respectively. Based on the estimated fair market value of the Company' s derivative contracts designated as hedges at September 30, 2011, the Company expects to reclassify net gains of $8.1 million into earnings from accumulated other comprehensive income during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially.

During the first quarter of 2011, the Company entered into one additional natural gas swap contract, three crude oil collars, and two crude oil swaps. The natural gas swap has a term of January 2012 to March 2013 with a volume amount of 75,000 MMBTUs per month. The swap has a fixed price of $4.85 per MMBTU. The first crude oil collar has a term of February 2011 through December 2011 with a volume amount of 5,000 Bbls per month. The floor price is $85.00 per Bbl and the ceiling price is $106.08 per Bbl on this contract. The second crude oil collar has a term of January 2012 through December 2012 and provides for 10,000 Bbls per month. The floor price is $85.00 per Bbl and the ceiling price is $110.00 per Bbl. The third crude oil collar has a term of March 2011 through December 2011 and provides for 5,000 Bbls per month. The floor price is $100.00 per Bbl and the ceiling price is $114.00 per Bbl. The first crude oil swap has a term of January 2012 through December 2012 and provides for 10,000 Bbls per month. The swap has a fixed price of $103.95 per Bbl. The second crude oil swap has a term of January 2013 through December 2013 and provides for 10,000 Bbls per month. The swap has a fixed price of $101.85 per Bbl.

During the second quarter of 2011, the Company entered into one additional crude oil swap. The crude oil swap has a term of May 2011 through December 2011 and provides for 6,250 Bbls per month. The swap has a fixed price of $110.00 per Bbl.

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At September 30, 2011, 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:			
2011	70,500		$74.37
2011	21,000		$88.45
2011	30,000		$85.05
2011	15,000		$85.16
2011	18,750		$110.00
2012	120,000		$86.85
2012	120,000		$87.22
2012	120,000		$103.95
2013	120,000		$101.85
Costless collar contracts			
2011	15,000	$85.00	$106.08
2011	15,000	$100.00	$114.00
2012	120,000	$85.00	$110.00
Natural Gas Contracts (Mmbtu)			
Swap contracts			
2011	210,000		$6.450
2012	150,000		$6.450
2012	450,000		$6.415
2012	900,000		$4.850
2013	225,000		$4.850
Costless collar contracts:			
2011	269,750	$7.00	$9.20

In 2010, the Company held two interest rate swaps, one of which was designated as a cash flow hedge, as discussed in Note D above. These swaps expired in October 2010.

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

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
Derivatives designated as ASC 815 hedges:	**Balance Sheet Location**	**Sept. 30, 2011**	**Dec. 31, 2010**	**Balance Sheet Location**	**Sept. 30, 2011**	**Dec. 31, 2010**
Commodity contracts	Current derivative financial instruments asset	$8,106	$4,282	Current derivative financial instruments liability	$ −	$(7,433)
Commodity contracts	Long-term derivative financial instruments asset	4,049	851	Long-term derivative financial instruments liability	−	(1,650)
		$12,155	$5,133		$ −	$(9,083)

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Commodity derivative contracts – The following table summarizes the effects of commodity derivative instruments on the consolidated statements of income for the three months ended September 30, 2011 and 2010 (in thousands):

Derivatives designated as ASC 815 hedges:	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) Sept. 30, 2011	Sept. 30, 2010	Location of Gain or (Loss) Reclassified from OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from OCI into Income (Effective Portion) Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	$ 15,972	$ 336	Oil and gas revenues	$ 551	$ 1,959
Interest rate swap contract	–	(12)	Interest expense	–	(408)
	$ 15,972	$ 324		$ 551	$ 1,551

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) Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	Hedge ineffectiveness	$ 103	$ 658

Derivatives 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 Sept. 30, 2011	Sept. 30, 2010
Realized cash settlements on interest rate swap	(Loss) on derivative contracts	$ –	$ (102)
Unrealized gains on interest rate swap	Gain on derivative contracts	–	100
		$ –	$ (2)

The following table summarizes the effects of commodity derivative instruments on the consolidated statements of income for the nine months ended September 30, 2011 and 2010 (in thousands):

Derivatives designated as ASC 815 hedges:	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) Sept. 30, 2011	Sept. 30, 2010	Location of Gain or (Loss) Reclassified from OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from OCI into Income (Effective Portion) Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	$14,684	$10,788	Oil and gas revenues	$(1,959)	$3,193
Interest rate swap contract	–	7	Interest expense	–	(1,214)
	$14,684	$10,795		$(1,959)	$1,979

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) Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	Hedge ineffectiveness	(538)	$974

Derivatives 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 Sept. 30, 2011	Sept. 30, 2010
Realized cash settlements on interest rate swap	Loss on derivative contracts	$ –	$ (303)
Unrealized gains on interest rate swap	Gain on derivative contracts	–	305
		$ –	$ 2

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 that are lenders under the Company' s credit facility. The Company uses credit facility participants to hedge with, since these institutions are secured equally with the holders of the Company' s debt, which eliminates the potential need to post collateral when the Company is in a large derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

NOTE H: 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.

Cash, Cash Equivalents, Accounts Receivable and Payable and Royalties Payable – 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 under its current credit facility at December 31, 2010 bears interest at floating market rates, so carrying amounts and fair values are approximately equal. There were no amounts outstanding under the current credit facility at September 30, 2011.

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 publically available interest rate yield curves, and is designated as Level 2 within the valuation hierarchy.

The table below presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of September 30, 2011 and December 31, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value.

Fair Value of Financial Assets and Liabilities−September 30, 2011
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balances as of September 30, 2011
Current portion of derivative financial instrument asset (1)	−	$ 8,106	−	$ 8,106
Long-term portion of derivative financial instrument asset (1)	−	4,049	−	4,049
Current portion of derivative financial instrument liability (1)	−	−	−	−
Long-term portion of derivative financial instrument liability (1)	−	−	−	−

(1) Commodity derivative instruments accounted for as cash flow hedges.

Fair Value of Financial Assets and Liabilities−December 31, 2010
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balances as of December 31, 2010
Current portion of derivative financial instrument asset (1)	−	$4,282	−	$4,282
Long-term portion of derivative financial instrument asset (1)	−	851	−	851
Current portion of derivative financial instrument liability (1)	−	(7,433)	−	(7,433)
Long-term portion of derivative financial instrument liability (1)	−	(1,650)	−	(1,650)

(1) Commodity derivative instruments accounted for as cash flow hedges.

At September 30, 2011, and December 31, 2010, 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. Also, there were no transfers between Level 1 and Level 2 as of September 30, 2011 and December 31, 2010.

Asset Impairments – The Company reviews proved oil and gas properties for impairment at least annually and when events and circumstances indicate a potential decline in the recoverability of the carrying value of such properties. When events and circumstances indicate a 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 significant Level 3 assumptions associated with estimates of future oil and gas production, commodity prices based on commodity futures price curves as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

The Company did not record any asset impairments on proved or unproved properties during the nine month period ended September 30, 2011. The Company recorded asset impairments of $2.7 million on proved properties during the nine month period ended September 30, 2010. Impairments were included in impairment expense. The significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis are 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 J.

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 curves 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 I: Public Offering of Common Stock

On January 19, 2011, the Company closed a public offering of 5,175,000 shares of common stock issued by the Company (including 675,000 shares of over allotment granted to underwriters) and 989,000 shares sold by certain selling shareholders in a public offering, at a price of $25.00 per share. The Company' s net proceeds from the offering were approximately $122.5 million after deducting the underwriters' discount and other offering expenses of $6.9 million.

NOTE J: 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, 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 nine months ended September 30, 2011, are as follows (in thousands):

Asset retirement obligation, January 1, 2011	$7,052
Accretion expense	336
Additional liabilities incurred	357
Disposals of property	(590)
Asset retirement obligation, September 30, 2011	$7,155

NOTE K: Related Party Transactions

Accounts receivable at September 30, 2011, and December 31, 2010, includes $508,000 and $753,000, respectively, due from SBE Partners LP ("SBE Partners"). Accounts receivable at September 30, 2011 and December 31, 2010, also includes $118,000 and $219,000, 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 September 30, 2011, and December 31, 2010, includes $2.7 million and $2.3 million, respectively, due to SBE Partners for oil and gas revenues collected on its behalf. Accounts payable at September 30, 2011, and December 31, 2010, also includes $951,000 and $654,000, respectively, due to OKLA Energy for oil and gas revenues collected on its behalf.

Subsidiaries of the Company operate the majority of the 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 behalf of the limited partnerships. These revenues are paid monthly to each limited partnership, which in turn reimburse the Company for the limited partnership' s share of expenditures. The Company earned management fees during the three months ended September 30, 2011 and 2010 of $127,000, and $124,000 respectively. The Company earned management fees during the nine months ended September 30, 2011 and 2010, of $369,000 and $423,000, respectively.

NOTE L: 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 net share of income and expenses in the Partnership Income line item of its Consolidated Statement of Income. Contributions to the investment increase the Company' s investment while distributions from the investment 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 partnership income related to this investment for the three and nine months ended September 30, 2011 of $3,000 and $12,000, respectively. The Company recorded losses in partnership income related to this investment for the three and nine months ended September 30, 2010 of $8,000 and $18,000, respectively.

SBE Partners, formed during 2007, holds direct working interests in producing oil and gas properties located in Giddings field, 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 SBE Partners, the cumulative payout was achieved and the Company' s general partner interest increased to 30%. The Company recorded partnership income related to this investment for the three months ended September 30, 2011 and 2010 of $631,000 and $437,000, respectively. The Company recorded partnership income related to this investment for the nine months ended September 30, 2011 and 2010 of $1.5 million and $1.8 million, respectively.

The Company' s carrying value for its equity investment in OKLA Energy at September 30, 2011 and December 31, 2010, was $696,000 and $709,000, respectively. The Company' s carrying value for its equity investment in SBE Partners at September 30, 2011 and December 31, 2010 was $2.0 million and $1.6 million, respectively.

The following is a summary of selected financial information of SBE Partners, LP for the nine months ended September 30, 2011 and 2010 (in thousands):

	Nine Months Ended September 30,	
	2011	2010
Summary of Partnership Operations:		
Revenues	$12,495	$14,939
Income from continuing operations	$4,761	$5,147
Net income	$4,761	$5,147

NOTE M: Subsequent Event

On October 19, 2011 the Company entered into a commitment letter with Wells Fargo Bank which contemplates amending the Company' s current credit facility to provide an amended and restated credit facility of up to $450 million, with an initial borrowing base of $180 million and a five year term. This commitment letter is subject to certain conditions precedent, including satisfactory commitments from participating lenders. This amended and restated credit facility is expected to be executed in November, 2011.

Item 2. ***Management' s Discussion and Analysis of Financial Condition and Results of Operations***

The following is Management' s Discussion and Analysis of significant factors that have affected certain aspects of our financial position and operating results during the periods included in the accompanying unaudited consolidated financial statements. This discussion should be read in conjunction with the accompanying unaudited consolidated financial statements and related notes thereto, included elsewhere in this Quarterly Report on Form 10-Q and should further be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2010.

Forward-Looking Information

Certain statements contained in this report on Form 10-Q are not statements of historical fact and constitute forward-looking statements within the meaning of the various provisions of the Securities Act of 1933, as amended, (the "Securities Act") and the Securities Exchange Act of 1934, as amended (the "Exchange Act"), including, without limitation, the statements specifically identified as forward-looking statements within this report. Many of these statements contain risk factors as well. In addition, certain statements in our future filings with the SEC, in press releases and in oral and written statements made by or with our approval which are not statements of historical fact constitute forward-looking statements within the meaning of the Securities Act and the Exchange Act. Examples of forward-looking statements, include, but are not limited to: (i) projections of capital expenditures, revenues, income or loss, earnings or loss per share, capital structure, and other financial items, (ii) statements of our plans and objectives or our management or board of directors including those relating to planned development of our oil and gas properties, (iii) statements of future economic performance and (iv) statements of assumptions underlying such statements. Words such as "believes," "anticipates," "expects," "intends," "targeted," "may," "will" and similar expressions are intended to identify forward-looking statements but are not the exclusive means of identifying such 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, worldwide demand and commodity prices for oil and natural gas;

changes in estimates of proved reserves;

declines in the values of our oil and natural gas properties resulting in impairments;

the timing and extent of our success in discovering, acquiring, developing and producing oil and natural gas reserves;

our ability to acquire leases, drilling rigs, supplies and services on a timely basis and at reasonable prices;

reductions in the borrowing base under our credit facility;

risks incident to the drilling and operation of oil and natural gas wells;

future production and development costs;

the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on prices;

the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America;

changes in environmental laws and the regulation and enforcement related to those laws;

the identification of and severity of environmental events and governmental responses to the events;

legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulation, derivatives reform, and changes in state, federal and foreign income taxes;

- the effect of oil and natural gas derivatives activities;
- conditions in the capital markets; and
- other risks, described in Item 1A, "Risk Factors," in our Annual Report on Form 10-K for the year ended December 31, 2010, as may be supplemented and updated from time to time in our other SEC filings.

Such forward-looking statements speak only as of the date on which such statements are made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made to reflect the occurrence of unanticipated events.

General Overview

We are an independent oil and gas company engaged in the acquisition, development and production of oil and gas reserves. As further discussed in this report, future growth in assets, earnings, cash flows and share values will be dependent upon our ability to 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.

Our strategy includes a combination of acquisition, development and exploration activities. Historically, we have shifted our emphasis among these basic activities to take advantage of changing market conditions and to facilitate profitable growth. The majority of our efforts are currently focused on developing our oil-weighted acreage positions in the Bakken trend of North Dakota and Montana and the Eagle Ford trend of Texas. In addition, it is essential that, over time, our personnel expand our current projects and/or generate additional projects so we have the potential of economically replacing our production and increasing our proved reserves. Following is a brief outline of our current plans:

- Develop our acreage positions in the Bakken and Eagle Ford trends;
- Expand our acreage positions and drilling inventory in our focus areas;
- Solicit industry partners, on a promoted basis, where we can retain operations and control large acreage positions in order to diversify, enhance economics and generate operating fees;
- Generate additional exploration and development projects;
- Acquire oil and gas properties with producing reserves and development and exploration potential, within our focus areas;
- Selectively divest assets to high-grade our producing property portfolio and to lower corporate wide "per-unit" operating and administrative costs, and focus attention on existing fields and new projects with greater development and exploitation potential; and
- Obtain additional capital, as needed, through the issuance of equity securities and/or through debt financing.

While the impact and success of our plans cannot be predicted with accuracy, management' s goal is to increase shareholder value by sourcing and investing in exploration and development projects with attractive full-cycle risk-adjusted economics.

In addition to our fundamental business strategy, we intend to pursue corporate acquisitions and mergers. We believe that a corporate acquisition or merger could potentially accelerate growth, increase market visibility and realize operating and administrative benefits. Accordingly, we intend to consider any such opportunities which may become available that we consider beneficial to our shareholders. The primary financial considerations in the evaluation of any potential transaction include, but is not limited to the opportunities: (1) to increase assets in our core focus areas, (2) to expand into new focus areas, if meaningful, (3) to increase our earnings and cash flow on a per share basis, (4) to increase development and exploration upside, (5) to expand quality staffing, and (6) to realize administrative savings. Further, we believe a corporate acquisition could lead to increased visibility in the market place, greater trading volume and therefore greater shareholder liquidity and possibly access to capital at lower costs.

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 and geological and geophysical costs 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 unit-of-production method, at the field level, based on proved reserves. Oil and gas properties are periodically assessed for impairment and generally written down to estimated fair value if the sum of estimated future undiscounted pretax cash flows, based on engineering and expected economic circumstances, is less than the carrying value of the asset. The fair value of impaired assets is generally determined using market values, if known, or using reasonable projections of production, prices and costs and discount rates commensurate with the risks involved.

Recent Property Acquisitions and Divestitures

In August 2011, the Company closed an acquisition of producing oil and gas properties located in the Austin Chalk trend of East Texas. The purchase price was $11 million plus closing adjustments for normal operating activity. The acquisition included approximately 3,700 net acres. For the three and nine months ended September 30, 2011, these properties contributed $570,000 of revenue to the Company.

In November 2010, the Company purchased an 86.67% membership interest in Trigon Energy Partners LLC ("Trigon") which held leases in the Eagle Ford shale trend of Texas and recorded a $2.2 million non-controlling interest in the financials. The acquisition cost was approximately $11.8 million. In June 2011, the Company' s membership interest decreased to 73.34% as a result of a $2.2 million capital contribution by the non-controlling interest holder. In September 2011, we deconsolidated the non-controlling interest due to a distribution of all of Trigon' s assets to Trigon' s owners.

In September 2010, the Company entered into an agreement with an unaffiliated third party to jointly acquire and develop mineral leases in the Eagle Ford shale trend of Texas. As part of this agreement, the Company sold a 50% working interest in approximately 20,000 acres for $20 million. For accounting purposes, the Company uses the cost recovery method; under this method proceeds from joint owners are recorded in the balance sheet as a reduction of the carrying value of unproved properties. The purchaser also agreed to pay 100% of the drilling costs for the first six wells to be drilled in a contractually specified area of mutual interest ("AMI"). The agreement also provides for an additional $20 million for additional joint leasing within the AMI ($10 million net to each entity). Subsequent to the initial closing, the Company and the joint owners have continued to acquire leases within the AMI pursuant to the terms of the agreement.

In July 2010, the Company closed an acquisition of producing oil and gas properties located in the Giddings field of central Texas. The purchase price was $16.6 million plus closing adjustments for normal operating activity. The acquisition included approximately 9,700 net acres and was funded through borrowings under the Company' s credit facility.

Results of Operations

Three months ended September 30, 2011, compared to three months ended September 30, 2010

The Company recorded net income of $9.4 million for the three months ended September 30, 2011 compared to net income of $7.6 million for the same period in 2010. This $1.8 million increase resulted primarily from the following factors:

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

Oil and natural gas sales	$9,617
Lease operating expenses	(1,667)
Production taxes	(847)
Exploration expense	(115)
Re-engineering and workovers	(152)
General and administrative expenses (“G&A”)	(1,121)
Depletion, depreciation and amortization expense (“DD&A”)	(1,187)
Hedge ineffectiveness	(553)
Gain (loss) on sale of property	(36)
Interest expense	909
Other income	592
Income before income taxes	5,440
Provision for income taxes	(3,661)
Increase in net income	$1,779

The following discussion applies to the above changes.

Oil and Natural Gas Sales. Net revenues from oil and natural gas sales increased $9.6 million, or 38%. Increases in commodity prices accounted for $5.7 million of the increase and increased oil production accounted for the remaining $3.9 million. Increased oil production was attributable primarily to new wells drilled during 2010 and 2011, as well as recent acquisitions, partially offset by normal production declines on previously existing wells. Price and production comparisons are set forth in the following table.

	Percent increase (decrease)	Three Months Ended September 30,	
		2011	2010
Oil Production (MBbls)	20%	331	276
Gas Production (MMcf)	0%	1,072	1,076
Barrel of Oil Equivalent (MBOE)	12%	510	455
Average Price Oil before Hedge Settlements (per Bbl)	30%	$90.06	$69.53
Average Price Oil after Hedge Settlements (per Bbl)	24%	$87.67	$70.43
Average Price Gas before Hedge Settlements (per Mcf)	9%	$4.51	$4.15
Average Price Gas after Hedge Settlements (per Mcf)	0%	$5.76	$5.74

Lease Operating Expenses. Lease operating expenses (“LOE”) increased from $5.1 million in the third quarter of 2010 to $6.8 million for the same period in 2011, an increase of $1.7 million or 32%. Our lease operating expenses have increased due to industry wide increases in costs and because oil operations have become a greater part of our overall production along with an increase in the total number of producing wells.

Re-engineering and workovers. Re-engineering and workover costs increased by $152,000, from $881,000 to $1,033,000. Re-engineering and workover projects occur in different fields and at different times due to operational matters and therefore when comparing quarterly expenditures, this variance is due to the timing of initiation and the size of individual projects.

Production Taxes. Production taxes increased by $847,000 or 56%, consistent with the increase in oil and gas revenues. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenues before the effects of hedging. Our production taxes for the quarters ended September 30, 2011 and 2010 were 6.8% and 6.4%, respectively, of oil and gas sales before the effects of hedging.

Exploration Expense. Our exploration costs were $278,000 for the third quarter of 2011 and $163,000 for the third quarter of 2010. The costs incurred during 2010 were primarily residual costs on an exploratory well deemed to be a dry hole prior to December 31, 2009. The costs incurred during 2011 were primarily geological and geophysical costs.

General and Administrative Expenses. G&A increased by $1.1 million, or 55%, due primarily to increases in personnel and office facilities. As our business has expanded we have also expanded our staff and office space. The total non-cash charges related to stock-based compensation included in G&A expense for the three month periods ended September 30, 2011 and 2010 were $656,000 and $299,000, respectively. The increase in non-cash charges related to stock-based compensation is a result of the issuance of restricted stock units during the second quarter of 2011.

Depreciation, Depletion and Amortization. DD&A expense increased by $1.2 million, or 19%. DD&A on oil and gas properties is computed on the units-of-production method, with production volumes as the numerator and estimated proved reserve volumes as the denominator. On a unit of production basis, DD&A per BOE increased from $13.63 in 2010 to $14.49 in 2011, increase of 6%. The increase is a result of increased activity in the Bakken and Eagle Ford trends in 2011 where wells are more costly to drill, resulting in higher finding and development costs, which gives rise to higher DD&A expense.

Interest Expense. Interest expense, inclusive of commitment fees and amortization of deferred financing costs, decreased by $909,000 due to no debt outstanding during the third quarter of 2011 compared to average outstanding debt of $80 million during the same period in 2010.

Hedge Ineffectiveness. In the third quarter of 2011 the gain from hedge ineffectiveness was $103,000 compared to a gain of $656,000 for the same period in 2010. During the third quarter of 2011 and 2010, our derivatives accounted for as cash flow hedges increased in value; therefore, the change in the ineffective portion of these derivatives was a gain in both periods.

Other Income. Other income increased by $592,000 in the third quarter of 2011 compared to the same period in 2010 due primarily to an increase in property operating income of $342,000, which was due to an increase in the number of operated wells and fees earned on operated wells drilled. Partnership income and partnership management fees also increased by $208,000 primarily due to production from a new well that was recently completed.

Income Tax Expense. Income tax expense for the third quarter of 2011 was $6.3 million compared to $2.6 million for the same period in 2010. Our income tax expense increased due to higher pre-tax earnings and a higher effective tax rate. Our effective tax rates during the third quarter of 2011 and 2010 were approximately 40% and 26%, respectively. The lower rate for 2010 is attributable to statutory deductions for excess depletion and domestic production activities, both of which represent permanent differences between financial statement income and taxable income.

Nine months ended September 30, 2011, compared to nine months ended September 30, 2010

The Company recorded net income of $24.5 million for the nine months ended September 30, 2011 compared to net income of $18.2 million for the same period in 2010. This $6.3 million increase resulted primarily from the following factors:

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

Oil and natural gas sales	$ 16,451
Lease operating expenses	(2,216)
Production taxes	(1,043)
Exploration expense	132
Re-engineering and workovers	(747)
General and administrative expenses (“G&A”)	(2,825)
Depletion, depreciation and amortization expense (“DD&A”)	(802)
Impairment expense	2,743
Hedge ineffectiveness	(1,514)
Gain (loss) on sale of property	556
Interest expense	2,429
Other Income	(297)
Income before income taxes	12,867
Provision for income taxes	(6,513)
Increase in net income	$6,354

The following discussion applies to the above changes.

Oil and Natural Gas Sales. Oil and natural gas sales increased $16.4 million, or 22%. Increased commodity prices accounted for $14.7 million of the increase and increased production volumes accounted for the remaining $1.7 million. Increased oil production was attributable primarily to new wells drilled during 2010 and 2011, as well as recent acquisitions, partially offset by normal production declines on previously existing wells. The decrease in natural gas production is due to our decision to suspend drilling of natural gas wells as a result of continued low natural gas prices. Price and production comparisons are set forth in the following table.

	Percent increase (decrease)	Nine Months Ended September 30, 2011	2010
Oil Production (MBbls)	9%	847	780
Gas Production (MMcf)	-16%	3,087	3,656
Barrel of Oil Equivalent (MBOE)	-2%	1,362	1,389
Average Price Oil before Hedge Settlements (per Bbl)	32%	$94.60	$71.78
Average Price Oil after Hedge Settlements (per Bbl)	25%	$87.94	$70.51
Average Price Gas before Hedge Settlements (per Mcf)	-1%	$4.21	$4.25
Average Price Gas after Hedge Settlements (per Mcf)	0%	$5.41	$5.39

Lease Operating Expenses. Lease operating expenses increased from approximately $15.4 million during the nine months ended September 30, 2010 to $17.6 million for the same period in 2011, an increase of $2.2 million or 14%. Our lease operating expenditures have increased due primarily to increased oil production as well as to industry-wide increases in service costs. Oil operations, with higher cost wells, have become a greater part of our overall production along with an increase in the total number of producing wells.

Re-engineering and Workover. Re-engineering and workover costs increased by $747,000 or 54% from $1.4 million to $2.1 million primarily due to a greater emphasis on remediation in today' s oil price environment.

Production Taxes. Production taxes increased by $1.0 million or 22%, due to increased production volumes and revenues. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenues before the effects of hedging. Our production taxes for the first nine months of 2011 and 2010 were 6.3% and 6.8%, respectively, of oil and gas sales before the effects of hedging.

Exploration and Impairment Costs. Our exploration costs were $634,000 for the nine months ended September 30, 2011 and $766,000 for the same period during 2010 a decrease of $132,000 or 17%. The costs incurred during 2011 were primarily geological and geophysical costs. In 2010, we incurred residual costs of $192,000 on an exploratory well deemed to be a dry hole prior to December 31, 2009. The remaining $574,000 in 2010 represents geological and geophysical costs. We also recorded non-cash impairment charges of $2.7 million, for the nine months ended 2010 due to the write-down of proved properties. The book value of these properties exceeded our estimate of future undiscounted cash flows which was a direct result of the decline in our estimated future natural gas prices.

General and Administrative Expenses. G&A increased $2.8 million or 48% in the first nine months of 2011 compared to the same period in 2010 due primarily to increases in personnel and office facilities. As our business has expanded, we have also expanded our staff and office space. Included in G&A expense for the nine months ended September 30, 2011 and 2010 are non-cash charges related to our stock-based compensation of $1.5 million and $793,000, respectively. The increase in non-cash charges related to stock-based compensation is a result of the issuance of restricted stock units during the second quarter of 2011.

Depreciation, Depletion and Amortization. DD&A expense increased by $802,000 or 4% due to higher capitalized costs and higher production. Capitalized costs increased due to acquisitions of additional property interests and continued successful drilling in the high cost Bakken projects. On a units-of- production basis, DD&A per BOE increased from $13.34 in 2010 to $14.18 in 2011, an increase of 6%. This increase is a result of increased activity in the Bakken and Eagle Ford trends in 2011 where wells are more costly to drill, resulting in higher finding and development costs, which gives rise to higher DD&A expense.

Interest Expense. Interest expense, inclusive of commitment fees and amortization of deferred financing costs, decreased by $2.4 million due to lower average debt levels during the first nine months of 2011, as compared to the same period in 2010. During the first nine months of 2011, our average outstanding debt was approximately $6.4 million compared to $72.7 million for the same period in 2010.

Hedge Ineffectiveness. For the first nine months of 2011 the loss from hedge ineffectiveness was $538,000, compared to a gain of $976,000 for the same period in 2010. During the nine months ended September 30, 2010, our derivatives accounted for as cash flow hedges increased in value; therefore, the change in the ineffective portion of these derivatives was a gain. During the first nine months of 2011, although our hedges increased in value, the correlation between our natural gas contract reference price and hedged price improved, thereby reducing the ineffectiveness gain.

Other Income. Other income decreased by $297,000 in the first nine months of 2011 compared to the same period in 2010. In 2010, we earned severance tax refunds of $1.2 million on certain high cost gas wells, compared to $302,000 in 2011. Property operating income increased by $919,000 due to an increase in the number of operated wells and fees earned on operated wells drilled. These increases were partially offset by a decrease in partnership income and partnership management fees of $276,000, which were primarily due to normal production declines, and decreases in other income of $11,000.

Income Tax Expense. Income tax expense for the first nine months of 2011 was $15.8 million compared to $9.3 million for the same period in 2010. Our income tax expense increased due to higher pre-tax earnings. Our effective tax rate during the first nine months of 2011 and 2010 was approximately 39% and 34%, respectively. The lower rate for 2010 is attributable to statutory deductions for excess depletion and domestic production activities, both of which represent permanent differences between financial statement income and taxable income.

Impact of Changing Prices and Costs

Our revenues and the carrying value of our oil and gas properties are impacted by significant changes in underlying oil and gas commodity prices. The oil and gas industry is cyclical and the demand for goods and services put significant pressure on the pricing structures within the industry and therefore have a direct impact on the underlying economics of our exploration and development programs. Typically, as prices for oil and natural gas increase, so do all associated costs of materials, services and personnel. However, in periods of declining prices, associated cost reductions may lag and not move downward in proportion to prices. Material changes in prices also impact the current revenue stream, estimates of future oil and gas reserves, depletion expense, impairment assessments of oil and gas properties due to low prices, and values of properties in purchase and sale transactions. Material changes in prices can impact the market value of shares of oil and gas companies and their ability to raise capital, borrow money and retain personnel.

Our average realized oil price of $87.94 per Bbl, net of hedges, for the nine months ended September 30, 2011, was 25% higher than for the comparable period in 2010. Our average realized natural gas price of $5.41 per Mcf, net of hedges, for the nine months ended September 30, 2011, was comparable to the price of $5.39 for the same period in 2010. The average realized prices for the nine months ended September 30, 2011, included the effects of our hedges. Should significant price decreases occur or should prices fail to remain at levels which will facilitate reinvestment of cash flow to economically replace current production, we could experience difficulty in developing our assets and growing our production and reserves.

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. Management believes our hedging strategy will result in greater predictability of internally generated funds, which can be dedicated to capital development projects and corporate obligations.

We do not engage in speculative commodity trading activities and do not hedge all available or anticipated quantities. Our strategy with regard to hedging includes the following factors:

(1) Secure and maintain favorable debt financing terms;

(2) Minimize price volatility and generate internal funds available for capital development projects and additional acquisitions;

(3) “Lock-in” growth in revenues, cash flows and profits for financial reporting purposes; and

(4) Allow certain quantities to float, particularly in months with high price potential.

We believe that commodity speculation and trading activities are inappropriate for us, but further believe appropriate management of realized prices is an integral part of managing our business strategy.

Administrative and Operating Costs

We continue to focus on cost-containment efforts regarding lower per-unit administrative and operating costs. However, we must continue to attract and retain competent management, technical and administrative personnel in pursuing our business strategy and fulfilling our contractual obligations. In seeking to grow our business, we have expanded our staff. As a result our general and administrative expenses increased in 2011 to date as compared to 2010.

Liquidity and Capital Resources

We expect to finance our future acquisition, development and exploration activities through working capital, cash flow from operating activities, use of our bank credit facility, sale of non-strategic assets, various means of corporate and project finance and possibly through the issuance of additional debt and equity securities. In addition, we intend to continue to partially finance our drilling activities through the sale of participations to industry partners on a promoted basis, whereby we will earn working interests in reserves and production greater than our proportionate capital cost.

Credit Facility

As of September 30, 2011, our borrowing base under our credit facility with Wells Fargo Bank (the “Bank”) was $145 million and we did not have any outstanding indebtedness. The borrowing base is subject to redetermination on May 1 and November 1 of each year.

On October 19, 2011 we entered into a commitment letter with the Bank which contemplates amending our current credit facility to provide an amended and restated credit facility of up to $450 million, with an initial borrowing base of $180 million and a five year term. This commitment letter is subject to certain conditions precedent, including satisfactory commitments from participating lenders. This amended and restated credit facility is expected to be executed in November, 2011.

Cash Flows from Operating Activities

For the nine months ended September 30, 2011, our net cash provided by operating activities was $67.0 million, versus $48.1 million in the same period in 2010. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next twelve months and for the foreseeable future. We expect to fund our planned capital program through our existing credit facility, working capital and projected cash flows.

Cash Flows from Investing Activities

Cash used for capital expenditures for the nine months ended September 30, 2011 and 2010, was $85.0 million and $65.3 million, respectively. In addition, cash generated from the sale of properties for the nine months ended September 30, 2011 and 2010 was $411,000 and $540,000, respectively. Capital expenditures for the first nine months of 2011 were financed with working capital. We expect to spend approximately $34.4 million in additional capital expenditures during the remainder of 2011 and between $188 million and $223 million in 2012.

Capital Spending

We continue to refine our capital budget for the remainder of 2011 and 2012. We currently expect our 2011 capital budget to be approximately $120 million, which is modestly higher than the previously disclosed forecast of $114 million. Through September 30, 2011 we have expended approximately $85.6 million of the budget. The 2012 capital expenditure budget will depend on how quickly we expand to three or four rigs in both the Eagle Ford and the Bakken. Our current expectation is for the 2012 capital budget to be between approximately $188 million and $223 million. The table below illustrates the components of the 2012 budget. A benefit of our property portfolio is that it consists of relatively new acreage positions and therefore we generally have two to four years to drill the bulk of our undeveloped leases. In addition, many of our drilling opportunities, including the bulk of our gas drilling locations, are “held by production” or long term leases and therefore not subject to lease expiration or significant future incremental carrying costs. Accordingly, we have a substantial ability to adjust our capital spending as industry circumstances dictate or as opportunities arise.

We have initiated drilling on our operated Bakken acreage in the Williston Basin and our operated Eagle Ford acreage in Texas. Further, our Bakken non-operated holdings continue to be actively developed by our operating partners. However, we continue to evaluate adjusting our expenditures between geographic areas and projects in an attempt to maximize production, reserve growth and cash flow and take advantage of regional differences in net commodity prices and service costs, while effectively transforming our acreage to held-by-production status.

While industry circumstances may require us to make capital expenditure adjustments, our capital budget reflects our current intent to develop our Bakken and Eagle Ford positions and further expand our acreage. To a lesser extent, we intend to drill certain locations in the Austin Chalk and certain of our prospects on the Gulf Coast, but those projects could be deferred in favor of increased activity in these other areas or so long as low natural gas prices prevail. Recent success within our Eagle Ford acreage block in Fayette County, Texas may allow us to establish a secondary Austin Chalk development program in our Eagle Ford area where the Austin Chalk is more oily.

The projects, estimated costs and timing of actual expenditures seen below 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. There can be no assurance that all of the projects identified and summarized in the table below will remain competitive or viable and therefore certain projects may be sold or abandoned by us to redeploy capital elsewhere. 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. Our current estimate of our capital expenditures for 2012 is as follows:

Estimated 2012 Capital Budget ($ in millions)

	Low (1)	High (2)	Notes
Bakken Operated Projects (North Dakota and Montana	$ 61	$ 73	23 to 26 gross wells (~31% W.I.)
Bakken Non-Operated Project (Primarily Mountrail County)	23	23	42 gross wells with Slawson (~8% W.I.); 12 with others (1% W.I.)
Eagle Ford (Fayette and Gonzales Counties)	74	86	21 to 24 gross wells (~40% W.I.)
Other Drilling and Operations	11	11	Williston Basin conventional, St. Martinville and Austin Chalk drilling
Acreage and Seismic	15	25	Primarily Eagle Ford and Bakken
Infrastructure and Other	4	5	Saltwater disposal and other infrastructure and equipment
Total Estimated 2012 Capital Expenditures	**$ 188**	**$ 223**	

NOTE: The data above is based on conservative well cost assumptions. Our goal is to reduce well costs below the amounts indicated above. Management believes that Bakken well costs of $7.5 million and Eagle Ford well costs of $8.0 million are attainable under current conditions.

(1) Assumes the Company increases to 3 drilling rigs in both the Bakken and Eagle Ford in 2012 with gross well costs of $8.0 million on operated Bakken wells and $8.5 million on operated Eagle Ford wells.

(2) Assumes the Company increases to 4 drilling rigs in both the Bakken and Eagle Ford by late 2012 with gross well costs of $8.5 million on operated Bakken wells and $9.0 million on operated Eagle Ford wells.

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Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Commodities. 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 may limit the benefit to us of increases in the prices of oil and natural gas, it also limits the downside risk of adverse price movements.

The following is a list of contracts outstanding at September 30, 2011:

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Remaining Annual Volumes	Fair Value Outstanding as of Sept. 30, 2011
						(in thousands)
Natural Gas						
October-07	Collar	01/01/11	12/31/11	$7.00 - $9.20	269,750 Mmbtu	$857
December-09	Swap	04/01/11	03/31/12	$6.450	360,000 Mmbtu	915
December-09	Swap	04/01/12	12/31/12	$6.415	450,000 Mmbtu	1,008
January-11	Swap	01/01/12	03/31/13	$4.850	1,125,000 Mmbtu	627
						3,407
Crude Oil						
October-07	Swap	01/01/11	12/31/11	$74.37	70,500 Bbls	(353)
January-10	Swap	01/01/11	12/31/11	$88.45	21,000 Bbls	190
August-10	Swap	09/01/10	12/31/11	$85.05	30,000 Bbls	167
August-10	Swap	01/01/12	12/31/12	$86.85	120,000 Bbls	697
October-10	Swap	01/01/11	12/31/11	$85.16	15,000 Bbls	85
October-10	Swap	01/01/12	12/31/12	$87.22	120,000 Bbls	740
January-11	Collar	02/01/11	12/31/11	$85.00 - $106.08	15,000 Bbls	176
January-11	Collar	01/01/12	12/31/12	$85.00 - $110.00	120,000 Bbls	1,233
March-11	Collar	03/01/11	12/31/11	$100.00 - $114.00	15,000 Bbls	312
March-11	Swap	01/01/12	12/31/12	$103.95	120,000 Bbls	2,758
March-11	Swap	01/01/13	12/31/13	$101.85	120,000 Bbls	2,169
April-11	Swap	05/01/11	12/31/11	$110.00	18,750 Bbls	574
						8,748
						$12,155

Interest rates. We are exposed to financial risk from changes in future interest rates to the extent that we incur future indebtedness. As of September 30, 2011, we did not have any outstanding indebtedness under our Second Amended and Restated Credit Agreement, which matures in October 2012. We anticipate entering into an amended and restated credit facility in November 2011 with an increased borrowing base (see Note M: Subsequent Event). The current credit facility provides for and we anticipate that the amended and restated credit facility will provide for a variable interest rate. In the event interest rates rise significantly, and we incur future indebtedness without mitigating or fixing future interest rates, our interest expense will increase in accordance with any future borrowings and at rates in effect at the time of those borrowings.

Item 4. ***Controls and Procedures***

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 September 30, 2011. 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 September 30, 2011, 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.

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 September 30, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

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

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

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A-Risk Factors" in our Annual Report for the year ended December 31, 2010 on Form 10-K, which could materially affect our business, financial condition or future results. The risks described in our 2010 Annual Report on Form 10-K may not be the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition and/or operating results.

Item 2.	***Unregistered Sales of Equity Securities and Use of Proceeds***	None
Item 3.	***Defaults Upon Senior Securities***	None
Item 4.	***Reserved***	
Item 5.	***Other Information***	None

Item 6. ***Exhibits***

EXHIBIT INDEX

FOR

Form 10-Q for the quarter ended September 30, 2011.

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)

101.INS XBRL Instance Document. (1)

101.SCH XBRL Schema Document. (1)

101.CAL XBRL Calculation Linkbase Document. (1)

101.DEF XBRL Definition Linkbase Document. (1)

101.LAB XBRL Label Linkbase Document. (1)

101.PRE XBRL Presentation Linkbase Document. (1)

(1) Filed herewith

SIGNATURES

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

GEORESOURCES, INC.

November 7, 2011

/s/ Frank A. Lodzinski

Frank A. Lodzinski
Chief Executive Officer (Principal Executive Officer)

/s/ Howard E. Ehler

Howard E. Ehler
Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)

EXHIBIT 31.1

Certification

I, Frank A. Lodzinski, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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 15(d-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
Principal Executive Officer
November 7, 2011

EXHIBIT 31.2

Certification

I, Howard E. Ehler, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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 (the 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
Principal Financial Officer
November 7, 2011

EXHIBIT 32.1

Section 1350 Certification

I, Frank A. Lodzinski, certify that:

In connection with the Quarterly Report on Form 10-Q of GeoResources, Inc. (the "*Company*") for the period ended September 30, 2011, 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 Act 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
(Principal Executive Officer)
November 7, 2011

* The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

EXHIBIT 32.2

Section 1350 Certification

I, Howard E. Ehler, certify that:

In connection with the Quarterly Report on Form 10-Q of GeoResources, Inc. (the "*Company*") for the period ended September 30, 2011, 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 Act 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
November 7, 2011

* The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

Consolidated Balance Sheets (Parenthetical) (USD $)	Sep. 30, 2011	Dec. 31, 2010
Consolidated Balance Sheets [Abstract]		
Common stock, par value	$ 0.01	$ 0.01
Common stock, shares authorized	100,000,000	100,000,000
Common stock, shares issued	25,571,480	19,726,566
Common stock, shares outstanding	25,571,480	19,726,566

Consolidated Statements Of Income (USD $) In Thousands, except Share data	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Revenue:				
Oil and gas revenues	$ 35,229	$ 25,612	$ 91,135	$ 74,684
Partnership management fees	127	124	369	423
Property operating income	840	498	2,201	1,282
Gain on sale of property and equipment	207	243	944	388
Partnership income	634	429	1,549	1,771
Interest and other	65	23	423	1,363
Total revenue	37,102	26,929	96,621	79,911
Expenses:				
Lease operating expense	6,813	5,146	17,579	15,363
Production taxes	2,367	1,520	5,886	4,843
Re-engineering and workovers	1,033	881	2,136	1,389
Exploration expense	278	163	634	766
Impairment of oil and gas properties				2,743
General and administrative expense	3,144	2,023	8,706	5,881
Depreciation, depletion and amortization	7,391	6,204	19,319	18,517
Hedge ineffectiveness	(103)	(656)	538	
Interest	482	1,391	1,520	3,949
Total expense	21,405	16,672	56,318	52,475
Income before income taxes	15,697	10,257	40,303	27,436
Income tax expense (benefit):				
Current	316	8,834	1,114	10,699
Deferred	5,966	(6,213)	14,682	(1,416)
Income Tax Expense (Benefit), Total	6,282	2,621	15,796	9,283
Net income	9,415	7,636	24,507	18,153
Less: Net loss attributable to noncontrolling interest			(87)	
Net income attributable to GeoResources, Inc.	$ 9,415	$ 7,636	$ 24,594	$ 18,153
Net income per share (basic)	$ 0.37	$ 0.39	$ 0.98	$ 0.92
Net income per share (diluted)	$ 0.36	$ 0.38	$ 0.96	$ 0.90
Weighted average shares outstanding:				
Basic	25,475,532	19,723,916	25,034,199	19,719,120
Diluted	25,844,758	20,080,670	25,486,593	20,076,472

Document And Entity Information	9 Months Ended Sep. 30, 2011	Nov. 04, 2011
Document And Entity Information [Abstract]		
Document Type	10-Q	
Amendment Flag	false	
Document Period End Date	Sep. 30, 2011	
Document Fiscal Period Focus	Q3	
Document Fiscal Year Focus	2011	
Entity Registrant Name	GEORESOURCES INC	
Entity Central Index Key	0000041023	
Current Fiscal Year End Date	--12-31	
Entity Filer Category	Accelerated Filer	
Entity Common Stock, Shares Outstanding		25,578,980

Long-Term Debt	9 Months Ended Sep. 30, 2011
Long-Term Debt [Abstract]	
Long-Term Debt	

NOTE D: Long-term debt

The Company has a $250 million credit facility with a borrowing base at September 30, 2011 of $145 million. The credit facility provides for annual interest rates at (a) LIBOR plus 2.25% to 3.00% or (b) the prime rate plus 1.25% to 2.00%, depending upon the amount borrowed. The credit facility also requires the payment of commitment fees to the lender on the unutilized commitment. 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 credit facility, and guarantees of those obligations, are secured by substantially all of the Company's assets.

The credit facility 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 September 30, 2011.

The Company has no principal outstanding under its credit facility at September 30, 2011. In the first quarter of 2011, the Company used certain net proceeds from the public offering of its common stock, discussed in Note I, to pay its outstanding indebtedness under the credit facility. The principal outstanding under the Company's credit facility was $87 million at December 31, 2010. The maturity date for amounts outstanding under the Second Amended and Restated Credit Agreement is October 16, 2012.

Interest expense for the three months ended September 30, 2011 and 2010 includes amortization of deferred financing costs of $272,000 and $265,000, respectively. Interest expense for the nine months ended September 30, 2011 and 2010 includes amortization of deferred financing costs of $805,000 and $793,000, respectively.

In connection with the initial borrowing from the bank under the credit facility the Company entered into an interest rate swap. The purpose was to protect the Company from undue exposure to interest rate increases. The swap agreement provided 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 rate of 4.29%. The $40 million swap was accounted for as a cash flow hedge while the $10 million swap was marked-to-market with gains and losses included in the Company's Consolidated Statement of Income. These swaps expired in October 2010.

For the three and nine months ended September 30, 2010, the Company recognized realized cash settlement losses of $408,000 and $1.2 million, respectively, related to the $40 million swap designated as a cash flow hedge.

Public Offering Of Common Stock	9 Months Ended Sep. 30, 2011
Public Offering Of Common Stock [Abstract]	
Public Offering Of Common Stock	**NOTE I: Public Offering of Common Stock** On January 19, 2011, the Company closed a public offering of 5,175,000 shares of common stock issued by the Company (including 675,000 shares of over allotment granted to underwriters) and 989,000 shares sold by certain selling shareholders in a public offering, at a price of $25.00 per share. The Company's net proceeds from the offering were approximately $122.5 million after deducting the underwriters' discount and other offering expenses of $6.9 million.

Consolidated Statements Of Cash Flows (Parenthetical) (USD $) In Thousands	9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010
Consolidated Statements Of Cash Flows [Abstract]		
Cost recoveries	$ 0	$ 20,230

Income Taxes	9 Months Ended Sep. 30, 2011
Income Taxes [Abstract]	
Income Taxes	

NOTE F: Income Taxes

Deferred income taxes are recorded to account for the tax effects associated with 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 amounts are measured using the enacted tax rates applicable to periods when these differences are expected to reverse.

Uncertain Tax Positions

The Company will consider a tax position settled if the taxing authority has completed its examinations, the Company does not plan to appeal the tax authority ruling, and the Company deems the possibility that the taxing authority will reexamine the tax position in the future as remote. For uncertain tax issues, 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 September 30, 2011, 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 as of September 30, 2011.

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

It is also the Company's practice 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 Statements of Income. As of September 30, 2011, the Company did not have any accrued interest or penalties associated with any unrecognized 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 September 30, 2012.

Related Party Transactions	9 Months Ended Sep. 30, 2011
Related Party Transactions [Abstract]	
Related Party Transactions	**NOTE K: Related Party Transactions** Accounts receivable at September 30, 2011, and December 31, 2010, includes $508,000 and $753,000, respectively, due from SBE Partners LP ("SBE Partners"). Accounts receivable at September 30, 2011 and December 31, 2010, also includes $118,000 and $219,000, 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 September 30, 2011, and December 31, 2010, includes $2.7 million and $2.3 million, respectively, due to SBE Partners for oil and gas revenues collected on its behalf. Accounts payable at September 30, 2011, and December 31, 2010, also includes $951,000 and $654,000, respectively, due to OKLA Energy for oil and gas revenues collected on its behalf. Subsidiaries of the Company operate the majority of the 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 behalf of the limited partnerships. These revenues are paid monthly to each limited partnership, which in turn reimburse the Company for the limited partnership's share of expenditures. The Company earned management fees during the three months ended September 30, 2011 and 2010 of $127,000, and $124,000 respectively. The Company earned management fees during the nine months ended September 30, 2011 and 2010, of $369,000 and $423,000, respectively.

Derivative Financial Instruments	9 Months Ended Sep. 30, 2011
Derivative Financial Instruments [Abstract]	
Derivative Financial Instruments	**NOTE G: Derivative Financial Instruments**

NOTE G: 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 may also limit future revenues from favorable price movements.

At September 30, 2011, accumulated other comprehensive income (loss) consisted of unrecognized gains of $7.3 million, net of taxes of $4.5 million, 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. At December 31, 2010, accumulated other comprehensive income (loss) consisted of unrecognized losses of $3.0 million, net of taxes of $1.8 million. For the three and nine months ended September 30, 2011, the Company recognized realized cash settlement gains of $551,000 and losses of $2.0 million, respectively. For the three and nine months ended September 30, 2010, the Company recognized net realized cash settlement gains on commodity derivatives of $2.0 million and $3.2 million respectively. Based on the estimated fair market value of the Company's derivative contracts designated as hedges at September 30, 2011, the Company expects to reclassify net gains of $8.1 million into earnings from accumulated other comprehensive income during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially.

During the first quarter of 2011, the Company entered into one additional natural gas swap contract, three crude oil collars, and two crude oil swaps. The natural gas swap has a term of January 2012 to March 2013 with a volume amount of 75,000 MMBTUs per month. The swap has a fixed price of $4.85 per MMBTU. The first crude oil collar has a term of February 2011 through December 2011 with a volume amount of 5,000 Bbls per month. The floor price is $85.00 per Bbl and the ceiling price is $106.08 per Bbl on this contract. The second crude oil collar has a term of January 2012 through December 2012 and provides for 10,000 Bbls per month. The floor price is $85.00 per Bbl and the ceiling price is $110.00 per Bbl. The third crude oil collar has a term of March 2011 through December 2011 and provides for 5,000 Bbls per month. The floor price is $100.00 per Bbl and the ceiling price is $114.00 per Bbl. The first crude oil swap has a term of January 2012 through December 2012 and provides for 10,000 Bbls per month. The swap has a fixed price of $103.95 per Bbl. The second crude oil swap has a term of January 2013 through December 2013 and provides for 10,000 Bbls per month. The swap has a fixed price of $101.85 per Bbl.

During the second quarter of 2011, the Company entered into one additional crude oil swap. The crude oil swap has a term of May 2011 through December 2011 and provides for 6,250 Bbls per month. The swap has a fixed price of $110.00 per Bbl.

At September 30, 2011, 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:			
2011	70,500		$74.37
2011	21,000		$88.45
2011	30,000		$85.05
2011	15,000		$85.16
2011	18,750		$110.00
2012	120,000		$86.85
2012	120,000		$87.22
2012	120,000		$103.95
2013	120,000		$101.85
Costless collar contracts			
2011	15,000	$85.00	$106.08
2011	15,000	$100.00	$114.00
2012	120,000	$85.00	$110.00
Natural Gas Contracts (Mmbtu)			
Swap contracts			
2011	210,000		$6.450
2012	150,000		$6.450
2012	450,000		$6.415
2012	900,000		$4.850
2013	225,000		$4.850
Costless collar contracts:			
2011	269,750	$7.00	$9.20

In 2010, the Company held two interest rate swaps, one of which was designated as a cash flow hedge, as discussed in Note D above. These swaps expired in October 2010.

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

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
Derivatives designated as ASC 815 hedges:	**Balance Sheet Location**	**Sept. 30, 2011**	**Dec. 31, 2010**	**Balance Sheet Location**	**Sept. 30, 2011**	**Dec. 31, 2010**
Commodity contracts	Current derivative financial instruments asset	$8,106	$4,282	Current derivative financial instruments liability	$ —	$(7,433)

Commodity contracts	Long-term derivative financial instruments asset	4,049	851	Long-term derivative financial instruments liability	—	(1,650)
		$12,155	$5,133		$ —	$(9,083)

Commodity derivative contracts – The following table summarizes the effects of commodity derivative instruments on the consolidated statements of income for the three months ended September 30, 2011 and 2010 (in thousands):

Derivatives designated as ASC 815 hedges:	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) Sept. 30, 2011	Sept. 30, 2010	Location of Gain or (Loss) Reclassified from OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from OCI into Income (Effective Portion) Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	$ 15,972	$ 336	Oil and gas revenues	$ 551	$ 1,959
Interest rate swap contract	—	(12)	Interest expense	—	(408)
	$ 15,972	$ 324		$ 551	$ 1,551

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) Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	Hedge ineffectiveness	$ 103	$ 658

Derivatives 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 Sept. 30, 2011	Sept. 30, 2010
Realized cash settlements on interest rate swap	(Loss) on derivative contracts	$ —	$ (102)
Unrealized gains on interest rate swap	Gain on derivative contracts	—	100
		$ —	$ (2)

The following table summarizes the effects of commodity derivative instruments on the consolidated statements of income for the nine months ended September 30, 2011 and 2010 (in thousands):

Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)	Location of Gain or (Loss) Reclassified from OCI into Income	Amount of Gain or (Loss) Reclassified from OCI into Income (Effective Portion)

Derivatives designated as ASC 815 hedges:	Sept. 30, 2011	Sept. 30, 2010	(Effective Portion)	Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	$ 14,684	$ 10,788	Oil and gas revenues	$ (1,959)	$ 3,193
Interest rate swap contract	—	7	Interest expense	—	(1,214)
	$ 14,684	$ 10,795		$ (1,959)	$ 1,979

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) Sept. 30, 2011	Sept. 30, 2010
Commodity contracts	Hedge ineffectiveness	(538)	$ 974

Derivatives 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 Sept. 30, 2011	Sept. 30, 2010
Realized cash settlements on interest rate swap	Loss on derivative contracts	$ —	$ (303)
Unrealized gains on interest rate swap	Gain on derivative contracts	—	305
		$ —	$ 2

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 that are lenders under the Company's credit facility. The Company uses credit facility participants to hedge with, since these institutions are secured equally with the holders of the Company's debt, which eliminates the potential need to post collateral when the Company is in a large derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

Stock Options, Performance Awards And Stock Warrants	9 Months Ended Sep. 30, 2011
Stock Options, Performance Awards And Stock Warrants [Abstract]	
Stock Options, Performance Awards And Stock Warrants	

NOTE E: 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. In June 2011, the shareholders of the Company approved an amendment to the Plan which increased the number of authorized issuances of stock-based incentives to 3,250,000 shares. The amendment also allows the issuance of performance units, including restricted stock units.

The options granted under the Plan can be designated as either incentive options or nonqualified options. The following is a summary of the terms of the June 2011 option grants by exercise price:

	Number of Shares Exercisable at:	
Vesting Date	$ 23.00	$ 27.00
Director		
June 6, 2012	5,000	5,000
June 6, 2013	5,000	5,000
June 6, 2014	5,000	5,000
June 6, 2015	5,000	5,000
	20,000	20,000

The closing market price of the Company's common stock on the date of the June 2011 option grants was $21.57.

The weighted-average fair value of the options granted during the nine months ended September 30, 2011, was $11.50 per share, using the following assumptions:

	June 7, 2011 Grant	
Risk-free interest rate	1.58	%
Dividend yield	None	
Volatility	67	%
Weighted average expected life of options	5.00	
Estimated forfeiture rate	1	%

A summary of the Company's stock option activity for the nine months ended September 30, 2011 is as follows:

	Number of Shares	Weighted Average	Weighted Average	Weighted Average	Aggregate Intrinsic Value

		Exercise Price	Fair Value	Remaining Contractual Life (year)	
Outstanding, December 31, 2010	1,494,350	$9.70	$3.49	7.34	$18,701,164
Granted	40,000	$25.00	$11.50		$—
Exercised	(678,414)	$9.28	$2.94		$11,780,546
Canceled/forfeited	(50,000)	$9.41	$3.22		$806,750
Outstanding, September 30, 2011	805,936	$10.83	$4.38	7.16	$5,942,466
Vested and exercisable	239,686	$9.41	$3.71	6.84	$2,021,441
Vested and expected to vest	801,573	$10.81	$4.36	7.15	$5,920,244

During the nine months ended September 30, 2011, 175,000 options vested with a weighted average exercise price of $10.15. The weighted average grant date fair value of these options was $4.81 per option. At September 30, 2011, there were 566,250 unvested options with a weighted average remaining amortization period of 2.04 years.

The Company recognizes compensation expense by first calculating the fair value of the options at the date of grant determined by the Black-Scholes option pricing model. The Company then amortizes the value of these options as compensation expense on a straight line basis over the vesting period of the options. For the quarters ended September 30, 2011 and 2010 the Company recognized compensation expense of $211,000 and $299,000, respectively, related to these options. For the nine month periods ended September 30, 2011 and 2010, the Company recognized compensation expense of $773,000 and $793,000, respectively, related to these options. As of September 30, 2011, the future un-amortized pre-tax compensation expense associated with non-vested stock options totaled $1.7 million to be recognized through the second quarter of 2015.

In addition to the stock option grants discussed above, during 2011, the Company granted certain officers, employees and directors 191,050 restricted stock units. Each restricted stock unit represents a contingent right to receive one share of the Company's common stock upon vesting. Compensation expense, determined by multiplying the number of restricted stock units granted by the closing market price of the Company's stock on the grant date, is recognized over the respective vesting periods on a straight-line basis. For the three and nine months ended September 30, 2011, compensation expense related to restricted stock units was $445,000 and $693,000, respectively. The Company has an assumed forfeiture rate of 1% on restricted stock issued. As of September 30, 2011, the future unamortized pre-tax compensation expense associated with unvested restricted stock units totaled approximately $4.6 million to be recognized through July 2014. The weighted average vesting period related to unvested restricted stock units at September 30, 2011 was approximately 2.6 years.

A summary of the Company's restricted stock unit activity for the nine months ended September 30, 2011 is as follows

	Shares	Fair Values (1)
Outstanding, December 31, 2010	—	—
Granted	191,050	$ 27.76
Vested	—	—
Forfeited	—	—
Outstanding, September 30, 2011	191,050	$ 27.76

(1) Represents the weighted average grant date market value

The Company has 613,336 outstanding warrants to purchase common stock outstanding at September 30, 2011. The warrants, which were acquired by non-affiliated accredited investors as part of the June 5, 2008 private placement offering, have an exercise price of $32.43 and have a remaining life of 1 year and 8 months.

Consolidated Statement Of Equity And Comprehensive Income (Parenthetical) (USD $) In Thousands	9 Months Ended Sep. 30, 2011
Consolidated Statement Of Equity And Comprehensive Income [Abstract]	
Common stock, issuance costs	$ 6,889
Tax on change in fair market value of hedged positions	5,569
Tax on hedging losses charged to income	$ 746

Organization And Basis Of Presentation	9 Months Ended Sep. 30, 2011
Organization And Basis Of Presentation [Abstract]	
Organization And Basis Of Presentation	

NOTE A: Organization and Basis of Presentation

Description of Operations

GeoResources, Inc. 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.

Consolidated Financial Statements

The unaudited consolidated financial statements include the accounts of GeoResources, Inc. ("GeoResources" or the "Company") and its majority-owned subsidiaries. We consolidated our non-controlling interest in Trigon LLC ("Trigon") until September 2011, at which time we deconsolidated the non-controlling interest due to a distribution of all of Trigon's assets to Trigon's owners. The financial statements have been prepared in accordance with U.S. generally accepted accounting principles for interim financial reporting. All intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, the accompanying financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim results. GeoResources' 2010 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in GeoResources' 2010 Annual Report on Form 10-K. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Earnings Per Share

Basic earnings per share is computed by dividing net income attributable to common shares by the basic weighted-average shares of common stock outstanding during the period. The calculation of diluted earnings per share is similar to basic, except the denominator includes the effect of dilutive common stock equivalents. Dilutive common stock equivalents consist of unvested restricted stock unit awards and outstanding stock options. The number of potential common shares outstanding relating to stock options and restricted stock units is computed using the treasury stock method. Net income per share computations reconciling basic and diluted net income for the three and nine months ended September 30, 2011 and 2010 consist of the following (in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Numerator:				
Net income attributable to common shares	$9,415	$7,636	$24,594	$18,153
Denominator:				

Basic weighted average shares	25,476	19,724	25,034	19,719
Effect of dilutive securities—share-based compensation	369	357	453	357
Diluted weighted average shares	25,845	20,081	25,487	20,076
Earnings per share				
Basic	$0.37	$0.39	$0.98	$0.92
Diluted	$0.36	$0.38	$0.96	$0.90

For the three month periods ended September 30, 2011 and 2010, options to purchase 16,400 and 71,477 shares of common stock, respectively, were excluded from the dilutive earnings per share calculation because the effect would have been anti-dilutive. For the nine month periods ended September 30, 2011 and 2010, options to purchase 4,600 and 70,543 shares of common stock, respectively, were excluded from the dilutive earnings per share calculation because the effect would be anti-dilutive.

For the three and nine month period ended September 30, 2011, approximately 5,900 and 6,200 restricted stock units, respectively, were excluded from the dilutive earnings per share calculation because their effect would be anti-dilutive.

For the three and nine month period ended September 30, 2011 and 2010, warrants to purchase 613,336 shares of common stock were excluded from the dilutive earnings per share calculation because the warrants' exercise price exceeded the average market price of the Company's common shares during these periods.

Acquisitions And Dispositions	9 Months Ended Sep. 30, 2011
Acquisitions And Dispositions[Abstract]	
Acquisitions And Dispositions	

NOTE B: Acquisitions and Dispositions

In August 2011, the Company closed an acquisition of producing oil and gas properties located in the Austin Chalk trend of East Texas. The purchase price was $11 million plus closing adjustments for normal operating activity. The acquisition included approximately 3,700 net acres. For the three and nine months ended September 30, 2011, these properties contributed $570,000 of revenue to the Company.

In November 2010, the Company purchased an 86.67% membership interest in Trigon Energy Partners LLC ("Trigon") which held leases in the Eagle Ford shale trend of Texas and recorded a $2.2 million non-controlling interest in the Company's financial statements. The acquisition cost was approximately $11.8 million. In June 2011, the Company's membership interest decreased to 73.34% as a result of a $2.2 million capital contribution by the non-controlling interest holder. In September 2011, we deconsolidated the non-controlling interest in the financial statements due to a distribution of all of Trigon's assets to Trigon's owners.

In September 2010, the Company entered into an agreement with an unaffiliated third party to jointly acquire and develop mineral leases in the Eagle Ford shale trend of Texas. As part of this agreement, the Company sold a 50% working interest in approximately 20,000 acres for $20 million. For accounting purposes, the Company uses the cost recovery method; under this method proceeds from joint owners are recorded in the balance sheet as a reduction of the carrying value of unproved properties. The purchaser also agreed to pay 100% of the drilling costs for the first six wells to be drilled in a contractually specified area of mutual interest ("AMI"). The agreement also provides for an additional $20 million for additional joint leasing within the AMI ($10 million net to each entity). Subsequent to the initial closing, the Company and the joint owners have continued to acquire leases within the AMI pursuant to the terms of the agreement.

In July 2010, the Company closed an acquisition of producing oil and gas properties located in the Giddings field of central Texas. The purchase price was $16.6 million plus closing adjustments for normal operating activity. The acquisition included approximately 9,700 net acres and was funded through borrowings under the Company's credit facility.

Asset Retirement Obligations	9 Months Ended Sep. 30, 2011
Asset Retirement Obligations [Abstract]	
Asset Retirement Obligations	**NOTE J: 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, 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 nine months ended September 30, 2011, are as follows (in thousands):

Asset retirement obligation, January 1, 2011	$7,052
Accretion expense	336
Additional liabilities incurred	357
Disposals of property	(590)
Asset retirement obligation, September 30, 2011	$7,155

Recently Issued Accounting Pronouncements	9 Months Ended Sep. 30, 2011
Recently Issued Accounting Pronouncements [Abstract]	
Recently Issued Accounting Pronouncements	**NOTE C: Recently Issued Accounting Pronouncements**

In June 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income. This update will require the presentation of the components of net income and other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In addition, companies are also required to present reclassification adjustments for items that are reclassified from other comprehensive income to net income on the face of the financial statements. The update is effective for fiscal years and interim periods beginning after December 15, 2011. The Company will adopt the new disclosure requirements for comprehensive income beginning January 1, 2012.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. This ASU issued authoritative guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. The ASU expands existing disclosure requirements for fair value measurements categorized in Level 3 by requiring (1) a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, (2) a description of the valuation processes in place, and (3) a narrative description of the sensitivity of the fair value to changes in unobservable inputs and the interrelationships between those inputs. Entities will also be required to disclose the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed.

Other amendments include clarifying the highest and best use and valuation premise for nonfinancial assets, premiums and discounts in fair value measurement, and fair value of an instrument classified in a reporting entity's shareholders' equity.

ASU 2011-04 is effective during interim and annual periods beginning after December 15, 2011, and therefore will become effective for the Company on January 1, 2012 for the quarter ending March 31, 2012. Other than the disclosure requirements, ASU 2011-04 is not expected to have a significant impact on the Company's consolidated financial statements.

Subsequent Event	9 Months Ended Sep. 30, 2011
Subsequent Event [Abstract]	
Subsequent Event	**NOTE M: Subsequent Event** On October 19, 2011 the Company entered into a commitment letter with Wells Fargo Bank which contemplates amending the Company's current credit facility to provide an amended and restated credit facility of up to $450 million, with an initial borrowing base of $180 million and a five year term. This commitment letter is subject to certain conditions precedent, including satisfactory commitments from participating lenders. This amended and restated credit facility is expected to be executed in November, 2011.

Consolidated Statement Of Equity And Comprehensive Income (USD $) In Thousands, except Share data	Common Stock [Member]	Additional Paid-In Capital [Member]	Retained Earnings [Member]	Accumulated Other Comprehensive Income (Loss) [Member]	Non-controlling Interest [Member]	Total
Balance at Dec. 31, 2010	$ 197	$ 148,172	$ 54,133	$ (3,000)	$ 2,233	$ 201,735
Balance, shares at Dec. 31, 2010	19,726,566					19,726,566
Issuance of common stock for cash, net of issuance costs of $6,889,shares	5,175,000					
Issuance of common stock for cash, net of issuance costs of $6,889	52	122,434				122,486
Exercise of employee stock options	7	6,040				6,047
Exercise of employee stock options, shares	669,914					
Excess tax benefit from share-based compensation		2,398				2,398
Comprehensive income:						
Net income			24,594		(87)	24,507
Change in fair market value of hedged positions, net of taxes of $5,569				9,115		9,115
Hedging gains realized in income, net of taxes of $746				1,213		1,213
Total comprehensive income						34,835
Equity based compensation expense		1,466				1,466
Deconsolidation of noncontrolling interest					(2,146)	(2,146)
Balance at Sep. 30, 2011	$ 256	$ 280,510	$ 78,727	$ 7,328		$ 366,821
Balance, shares at Sep. 30, 2011	25,571,480					25,571,480

Consolidated Statements Of Cash Flows (USD $) In Thousands	9 Months Ended Sep. 30, 2011	Sep. 30, 2010
Cash flows from operating activities:		
Net income	$ 24,507	$ 18,153
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	19,319	18,517
Proved property impairments		2,743
Gain on sale of property and equipment	(944)	(388)
Accretion of asset retirement obligations	336	300
Unrealized gain on derivative contracts		(305)
Hedge ineffectiveness (gain) loss	538	
Partnership income	(1,549)	(1,771)
Partnership distributions	1,126	2,919
Deferred income taxes	14,682	(1,416)
Non-cash compensation	1,466	793
Excess tax benefit from share-based compensation	(2,398)	
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(12,262)	10,285
(Increase) decrease in prepaid expense and other	250	988
(Decrease) increase in accounts payable and accrued expense	18,434	(804)
(Decrease) increase in revenues and royalties payable	3,528	(930)
Net cash provided by operating activities	67,033	48,110
Cash flows from investing activities:		
Proceeds from sale of property and equipment	411	540
Additions to property and equipment, net of acreage cost recoveries of none in 2011 and recoveries of $20,230 in 2010	(84,999)	(65,282)
Net cash used in investing activities	(84,588)	(64,742)
Cash flows from financing activities:		
Proceeds from stock options exercised	6,047	103
Issuance of common stock	122,486	
Excess tax benefit from share-based compensation	2,398	
Issuance of long-term debt		16,000
Reduction of long-term debt	(87,000)	
Net cash provided by financing activities	43,931	16,103
Net increase (decrease) in cash and cash equivalents	26,376	(529)
Cash and cash equivalents at beginning of period	9,370	12,660
Cash and cash equivalents at end of period	35,746	12,131
Supplementary information:		
Interest paid	696	3,161
Income taxes paid	998	2,629
Non-cash investing activities		
Accounts receivable-acreage cost recoveries		$ 20,000

Fair Value Disclosures	9 Months Ended Sep. 30, 2011
Fair Value Disclosures [Abstract]	
Fair Value Disclosures	

NOTE H: 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.

Cash, Cash Equivalents, Accounts Receivable and Payable and Royalties Payable – 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 under its current credit facility at December 31, 2010 bears interest at floating market rates, so carrying amounts and fair values are approximately equal. There were no amounts outstanding under the current credit facility at September 30, 2011.

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 publically available interest rate yield curves, and is designated as Level 2 within the valuation hierarchy.

The table below presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of September 30, 2011 and December 31, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value.

Fair Value of Financial Assets and Liabilities—September 30, 2011
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balances as of September 30, 2011
Current portion of derivative financial instrument asset (1)	—	$ 8,106	—	$ 8,106
Long-term portion of derivative financial instrument asset (1)	—	4,049	—	4,049
Current portion of derivative financial instrument liability (1)	—	—	—	—
Long-term portion of derivative financial instrument liability (1)	—	—	—	—

(1) Commodity derivative instruments accounted for as cash flow hedges.

Fair Value of Financial Assets and Liabilities—December 31, 2010
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balances as of December 31, 2010
Current portion of derivative financial instrument asset (1)	—	$4,282	—	$4,282
Long-term portion of derivative financial instrument asset (1)	—	851	—	851
Current portion of derivative financial instrument liability (1)	—	(7,433)	—	(7,433)

Long-term portion of derivative financial instrument liability [1]	—	(1,650)	—	(1,650)

(1) Commodity derivative instruments accounted for as cash flow hedges.

At September 30, 2011, and December 31, 2010, 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. Also, there were no transfers between Level 1 and Level 2 as of September 30, 2011 and December 31, 2010.

Asset Impairments – The Company reviews proved oil and gas properties for impairment at least annually and when events and circumstances indicate a potential decline in the recoverability of the carrying value of such properties. When events and circumstances indicate a 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 significant Level 3 assumptions associated with estimates of future oil and gas production, commodity prices based on commodity futures price curves as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

The Company did not record any asset impairments on proved or unproved properties during the nine month period ended September 30, 2011. The Company recorded asset impairments of $2.7 million on proved properties during the nine month period ended September 30, 2010. Impairments were included in impairment expense. The significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis are 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 J.

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 curves 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.

Equity Investments	**9 Months Ended Sep. 30, 2011**
Equity Investments [Abstract]	
Equity Investments	

NOTE L: 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 net share of income and expenses in the Partnership Income line item of its Consolidated Statement of Income. Contributions to the investment increase the Company's investment while distributions from the investment 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 partnership income related to this investment for the three and nine months ended September 30, 2011 of $3,000 and $12,000, respectively. The Company recorded losses in partnership income related to this investment for the three and nine months ended September 30, 2010 of $8,000 and $18,000, respectively.

SBE Partners, formed during 2007, holds direct working interests in producing oil and gas properties located in Giddings field, 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 SBE Partners, the cumulative payout was achieved and the Company's general partner interest increased to 30%. The Company recorded partnership income related to this investment for the three months ended September 30, 2011 and 2010 of $631,000 and $437,000, respectively. The Company recorded partnership income related to this investment for the nine months ended September 30, 2011 and 2010 of $1.5 million and $1.8 million, respectively.

The Company's carrying value for its equity investment in OKLA Energy at September 30, 2011 and December 31, 2010, was $696,000 and $709,000, respectively. The Company's carrying value for its equity investment in SBE Partners at September 30, 2011 and December 31, 2010 was $2.0 million and $1.6 million, respectively.

The following is a summary of selected financial information of SBE Partners, LP for the nine months ended September 30, 2011 and 2010 (in thousands):

	Nine Months Ended September 30,	
	2011	**2010**
Summary of Partnership Operations:		
Revenues	$12,495	$14,939
Income from continuing operations	$4,761	$5,147
Net income	$4,761	$5,147

Consolidated Balance Sheets (USD $) In Thousands	Sep. 30, 2011	Dec. 31, 2010
Current assets:		
Cash	$ 35,746	$ 9,370
Accounts receivable:		
Oil and gas revenues	22,850	17,017
Joint interest billings and other	23,313	16,631
Affiliated partnerships	626	969
Notes receivable	537	120
Derivative financial instruments	8,106	4,282
Income taxes receivable	2,447	222
Prepaid expenses and other	3,271	2,645
Total current assets	96,896	51,256
Oil and gas properties, successful efforts method:		
Proved properties	404,611	341,582
Unproved properties	48,014	32,403
Office and other equipment	1,505	1,140
Land	146	146
Total property and equipment	454,276	375,271
Less accumulated depreciation, depletion and amortization	(88,416)	(72,380)
Net property and equipment	365,860	302,891
Equity in oil and gas limited partnerships	2,696	2,272
Derivative financial instruments	4,049	851
Deferred financing costs and other	1,477	2,420
Total Assets	470,978	359,690
Current liabilities:		
Accounts payable	14,286	14,616
Accounts payable to affiliated partnerships	3,694	2,931
Revenue and royalties payable	15,769	12,450
Drilling advances	19,266	4,203
Accrued expenses	3,702	1,331
Derivative financial instruments		7,433
Total current liabilities	56,717	42,964
Long-term debt		87,000
Deferred income taxes	40,285	19,289
Asset retirement obligations	7,155	7,052
Derivative financial instruments		1,650
Stockholders' equity:		
Common stock, par value $0.01 per share; authorized 100,000,000 shares; issued and outstanding: 25,571,480 in 2011 and 19,726,566 in 2010	256	197
Additional paid-in capital	280,510	148,172
Accumulated other comprehensive income	7,328	(3,000)
Retained earnings	78,727	54,133

Total GeoResources, Inc. stockholders' equity	366,821	199,502
Noncontrolling interest		2,233
Total equity	366,821	201,735
Total Liabilities and Equity	$ 470,978	$ 359,690