GULFPORT ENERGY CORP
Form 10-Q
November 06, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE QUARTERLY PERIOD ENDED September 30, 2009

OR

¨ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 000-19514

Gulfport Energy Corporation

(Exact Name of Registrant As Specified in Its Charter)

Delaware	**73-1521290**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification Number)**
14313 North May Avenue, Suite 100	
Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	**(Zip Code)**

(405) 848-8807

(Registrant 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 past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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

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

Large Accelerated Filer	¨	Accelerated Filer	x
Non-Accelerated Filer	¨	Smaller Reporting Company	¨

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

As of November 2, 2009, 42,688,491 shares of common stock were outstanding.

GULFPORT ENERGY CORPORATION

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	(Unaudited) September 30, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 7,076,000	$ 5,944,000
Accounts receivable - oil and gas	9,208,000	12,543,000
Accounts receivable - related parties	146,000	1,101,000
Prepaid expenses and other current assets	1,624,000	1,045,000
Total current assets	18,054,000	20,633,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $17,020,000 and $22,543,000 excluded from amortization in 2009 and 2008, respectively	612,554,000	599,761,000
Other property and equipment	7,182,000	7,168,000
Accumulated depletion, depreciation, amortization and impairment	(466,847,000)	(444,690,000)
Property and equipment, net	152,889,000	162,239,000
Other assets		
Equity investments	28,459,000	25,440,000
Other assets	3,491,000	3,755,000
Note receivable - related party	14,497,000	9,153,000
Total other assets	46,447,000	38,348,000
Deferred tax asset	653,000	653,000
Total assets	$ 218,043,000	$ 221,873,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 18,915,000	$ 27,772,000
Asset retirement obligation - current	635,000	635,000
Short-term derivative instruments	11,800,000	
Current maturities of long-term debt	50,841,000	815,000
Total current liabilities	82,191,000	29,222,000
Long-term derivative instruments	2,856,000	
Asset retirement obligation - long-term	9,255,000	8,634,000
Long-term debt, net of current maturities	4,787,000	69,916,000

Total liabilities	99,089,000	107,772,000
Commitments and contingencies (Note 10)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding		
Stockholders equity:		
Common stock - $.01 par value, 55,000,000 authorized, 42,687,690 issued and outstanding in 2009 and 42,639,201 in 2008	426,000	426,000
Additional paid-in capital	273,800,000	273,343,000
Accumulated other comprehensive loss	(14,892,000)	(4,803,000)
Accumulated deficit	(140,380,000)	(154,865,000)
Total stockholders equity	118,954,000	114,101,000
Total liabilities and stockholders equity	$ 218,043,000	$ 221,873,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues:				
Oil and condensate sales	$ 21,142,000	$ 34,354,000	$ 58,146,000	$ 95,636,000
Gas sales	498,000	1,337,000	1,114,000	5,612,000
Natural gas liquids sales	533,000	1,216,000	1,432,000	2,784,000
Other income (expense)	(102,000)	(176,000)	(323,000)	(381,000)
	22,071,000	36,731,000	60,369,000	103,651,000
Costs and expenses:				
Lease operating expenses	3,442,000	6,362,000	12,511,000	14,906,000
Production taxes	2,586,000	3,970,000	6,856,000	11,398,000
Depreciation, depletion, and amortization	7,387,000	9,392,000	22,157,000	28,912,000
General and administrative	1,380,000	1,748,000	3,659,000	5,270,000
Accretion expense	146,000	140,000	432,000	417,000
	14,941,000	21,612,000	45,615,000	60,903,000
INCOME FROM OPERATIONS:	7,130,000	15,119,000	14,754,000	42,748,000
OTHER (INCOME) EXPENSE:				
Interest expense	614,000	1,172,000	1,686,000	3,402,000
Insurance proceeds			(1,050,000)	(769,000)
Interest income	(158,000)	(180,000)	(395,000)	(404,000)
	456,000	992,000	241,000	2,229,000
INCOME BEFORE INCOME TAXES	6,674,000	14,127,000	14,513,000	40,519,000
INCOME TAX EXPENSE:		20,000	28,000	20,000
NET INCOME	$ 6,674,000	$ 14,107,000	$ 14,485,000	$ 40,499,000
NET INCOME PER COMMON SHARE:				
Basic	$ 0.16	$ 0.33	$ 0.34	$ 0.95
Diluted	$ 0.16	$ 0.33	$ 0.34	$ 0.94

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders Equity
Balance at January 1, 2009	42,639,201	$ 426,000	$ 273,343,000	$ (4,803,000)	$ (154,865,000)	$ 114,101,000
Net income					14,485,000	14,485,000
Other Comprehensive Income:						
Foreign currency translation adjustment				4,566,000		4,566,000
Change in fair value of derivative instruments				(9,693,000)		(9,693,000)
Reclassification of settled contracts				(4,962,000)		(4,962,000)
Total Comprehensive Income						4,396,000
Stock Compensation			428,000			428,000
Issuance of Restricted Stock	34,739					
Issuance of Common Stock through exercise of options	13,750		29,000			29,000
Balance at September 30, 2009	42,687,690	$ 426,000	$ 273,800,000	$ (14,892,000)	$ (140,380,000)	$ 118,954,000
Balance at January 1, 2008	42,453,587	$ 424,000	$ 271,807,000	$ 2,254,000	$ 29,637,000	$ 304,122,000
Net income					40,499,000	40,499,000
Other Comprehensive Income:						
Foreign currency translation adjustment				(2,349,000)		(2,349,000)
Total Comprehensive Income						38,150,000
Stock Compensation			816,000			816,000
Issuance of Restricted Stock	27,015					
Issuance of Common Stock through exercise of options	144,121	2,000	480,000			482,000
Balance at September 30, 2008	42,624,723	$ 426,000	$ 273,103,000	$ (95,000)	$ 70,136,000	$ 343,570,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flows from operating activities:		
Net income	$ 14,485,000	$ 40,499,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount - Asset Retirement Obligation	432,000	417,000
Depletion, depreciation and amortization	22,157,000	28,912,000
Stock-based compensation expense	257,000	490,000
Loss from equity investments	427,000	540,000
Interest income - note receivable	(380,000)	(290,000)
Changes in operating assets and liabilities:		
Decrease in accounts receivable	3,335,000	1,559,000
Decrease in accounts receivable - related party	955,000	1,753,000
Increase in prepaid expenses	(579,000)	(20,000)
(Decrease) increase in accounts payable and accrued liabilities	(5,242,000)	1,727,000
Settlements of asset retirement obligation	(35,000)	(324,000)
Net cash provided by operating activities	35,812,000	75,263,000
Cash flows from investing activities:		
Deductions (additions) to cash held in escrow	8,000	(36,000)
Additions to other property, plant and equipment	(14,000)	(57,000)
Additions to oil and gas properties	(33,450,000)	(92,993,000)
Proceeds from sale of oil and gas properties	17,694,000	
Note receivable - related party	(3,451,000)	(9,708,000)
Investment in Grizzly Oil Sands ULC		(151,000)
Investment in Tatex Thailand II, LLC	(3,000)	432,000
Investment in Tatex Thailand III, LLC	(390,000)	(885,000)
Net cash used in investing activities	(19,606,000)	(103,398,000)
Cash flows from financing activities:		
Principal payments on borrowings	(15,103,000)	(600,000)
Borrowings on line of credit		30,000,000
Proceeds from issuance of common stock and exercise of stock options	29,000	482,000
Net cash (used in) provided by financing activities	(15,074,000)	29,882,000
Net increase in cash and cash equivalents	1,132,000	1,747,000
Cash and cash equivalents at beginning of period	5,944,000	2,764,000
Cash and cash equivalents at end of period	$ 7,076,000	$ 4,511,000

Supplemental disclosure of cash flow information:

Interest payments	$ 1,561,000	$ 3,534,000
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$ 171,000	$ 326,000
Asset retirement obligation capitalized	$ 224,000	$ 528,000
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$ 3,053,000	$ (1,862,000)
Foreign currency translation gain (loss) on note receivable - related party	$ 1,513,000	$ (487,000)

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

These consolidated financial statements have been prepared by Gulfport Energy Corporation (the Company or Gulfport) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission, and reflect all adjustments which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods, on a basis consistent with the annual audited consolidated financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to such rules and regulations, although the Company believes that the disclosures are adequate to make the information presented not misleading. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the summary of significant accounting policies and notes thereto included in the Company s most recent annual report on Form 10-K. Results for the three month and nine month periods ended September 30, 2009 are not necessarily indicative of the results expected for the full year.

1. ACCOUNTS RECEIVABLE RELATED PARTY

Included in the accompanying September 30, 2009 and December 31, 2008 consolidated balance sheets are amounts receivable from affiliates of the Company. These receivables represent amounts billed by the Company for general and administrative functions, such as accounting, human resources, legal, and technical support, performed by Gulfport s personnel on behalf of the affiliates. These services are solely administrative in nature and for entities in which the Company has no property interests. The amounts reimbursed to the Company for these services are for the purpose of Gulfport recovering costs associated with the services and do not include the assessment of any fees or other amounts beyond the estimated costs of performing such services. At September 30, 2009 and December 31, 2008, these receivable amounts totaled $146,000 and $1,101,000, respectively. The Company was reimbursed $101,000 and $593,000 for the three months and nine months ended September 30, 2009, respectively, for general and administrative functions which are reflected as a reduction of general and administrative expenses in the consolidated statements of operations and include the amounts under service contracts discussed below. For the three months and nine months ended September 30, 2008, the Company was reimbursed $74,000 and $1,176,000, respectively.

The Company is a party to an administrative services agreement with Great White Energy Services LLC and had been a party to administrative service agreements with Caliber Development Company, LLC and Diamondback Energy Services LLC until December 8, 2008. Under the agreements, the Company s services include or included accounting, human resources, legal and technical support. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each administrative service agreement has or had a three-year term, and upon expiration of that term such agreement will continue on a month-to-month basis until cancelled by either party to such agreement with at least 30 days prior written notice. Each administrative service agreement is or was terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

The Company is also a party to administrative service agreements with Stampede Farms LLC, Grizzly Oil Sands ULC, Everest Operations Management LLC and Tatex Thailand III, LLC. Under the agreements, the Company s services include professional and technical support and office space. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a two-year term, and upon expiration of that term such agreement will continue on a month-to-month basis until cancelled by either party to such agreement with at least 60 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

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The Company was reimbursed the following amounts by the specified entities in consideration for its administrative services for the three months and nine months ended September 30, 2009 and 2008. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations. Wexford Capital LP (Wexford) controls and/or owns a greater than 10% interest in each of these entities. Affiliates of Wexford own approximately 36% of Gulfport s outstanding stock.

Agreement Effective Date	Entity	Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
2/9/2005	Caliber Development Company, LLC *	$	$	$	$ 60,000
7/22/2006	Great White Energy Services LLC	17,000	15,000	61,000	68,000
9/26/2006	Diamondback Energy Services LLC *				10,000
3/1/2008	Stampede Farms LLC				159,000
3/1/2008	Grizzly Oil Sands ULC	3,000	28,000	20,000	353,000
3/1/2008	Everest Operations Management LLC	80,000		508,000	
3/1/2008	Tatex Thailand III, LLC				

* Agreement was terminated effective December 10, 2008.

For the nine months ended September 30, 2009, the Company was also reimbursed approximately $2,000 and $1,000 by Stampede Farms LLC and Everest Operations Management LLC, respectively, for office space under the administrative service agreements, which is included in other income (expense) in the consolidated statements of operations.

Effective July 1, 2008, the Company is a party to an acquisition team agreement with Everest Operations Management LLC (Everest) to identify and evaluate potential oil and gas properties in which the Company and Everest may wish to invest. Upon a successful closing of an acquisition or divestiture, the party identifying the acquisition or divestiture is entitled to receive a fee from the other party and its affiliates, if applicable, participating in such closing. The fee is equal to 1% of the party s proportionate share of the acquisition or divestiture consideration. The agreement may be terminated by either party upon 30 days notice.

2. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of September 30, 2009 and December 31, 2008 are as follows:

	September 30, 2009	December 31, 2008
Oil and natural gas properties	$ 612,554,000	$ 599,761,000
Office furniture and fixtures	2,996,000	2,982,000
Building	3,926,000	3,926,000
Land	260,000	260,000
Total property and equipment	619,736,000	606,929,000
Accumulated depletion, depreciation, amortization and impairment	(466,847,000)	(444,690,000)
Property and equipment, net	$ 152,889,000	$ 162,239,000

Included in oil and natural gas properties at September 30, 2009 is the cumulative capitalization of $13,099,000 in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $934,000 and $2,485,000 for the three months and nine months ended September 30, 2009, respectively, and $1,165,000 and $3,512,000 for the three months and nine months ended September 30, 2008, respectively.

At September 30, 2009, approximately $2,302,000 of oil and natural gas properties related to the Company s Belize properties is excluded from amortization as it relates to non-producing properties. In addition, approximately $12,845,000 of non-producing leasehold costs resulting from the Company s acquisition of West Texas Permian properties and $366,000 of non-producing leasehold costs related to the Company s Bakken properties are excluded from amortization at September 30, 2009. Approximately $1,507,000 of non-producing leasehold costs related to the Company s Southern Louisiana assets is also excluded from amortization at September 30, 2009.

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The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company s activities, the inclusion of most of the above referenced costs into the Company s amortization calculation is expected to occur within three to five years.

A reconciliation of the asset retirement obligation for the nine months ended September 30, 2009 and 2008 is as follows:

	September 30, 2009	September 30, 2008
Asset retirement obligation, beginning of period	$ 9,269,000	$ 8,634,000
Liabilities incurred	224,000	528,000
Liabilities settled	(35,000)	(324,000)
Accretion expense	432,000	417,000
Asset retirement obligation as of end of period	9,890,000	9,255,000
Less current portion	635,000	480,000
Asset retirement obligation, long-term	$ 9,255,000	$ 8,775,000

3. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of September 30, 2009 and December 31, 2008.

	September 30, 2009	December 31, 2008
Investment in Tatex Thailand II, LLC	$ 2,686,000	$ 2,683,000
Investment in Tatex Thailand III, LLC	1,237,000	876,000
Investment in Grizzly Oil Sands ULC	24,536,000	21,881,000
	$ 28,459,000	$ 25,440,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC (Tatex) at a cost of $2,400,000. The remaining interests in Tatex are owned by entities controlled by Wexford, an affiliate of Gulfport. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (APICO), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During the nine months ended September 30, 2009, Gulfport received $317,000 in distributions and paid $320,000 in cash calls, bringing its net investment in Tatex (including previous investments) to $2,686,000. The Company recognized a loss on equity investment of $6,000 for the nine months ended September 30, 2008 which is included in other income (expense) in the consolidated statements of operations. The loss on equity investment related to Tatex was immaterial for the nine months ended September 30, 2009.

Tatex Thailand III, LLC

During the first quarter of 2008, the Company purchased a 5% ownership interest in Tatex Thailand III, LLC (Tatex III) at a cost of $850,000. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford, an affiliate of Gulfport. During the nine months ended September 30, 2009, Gulfport paid $390,000 in cash calls, bringing its total investment in Tatex III (including previous investments) to $1,237,000. The Company recognized a loss on equity investment of $29,000 and $8,000 for the nine months ended September 30, 2009 and 2008, respectively, which is included in other income (expense) in the consolidated statements of operations.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oils Sands ULC (Grizzly), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by entities controlled by Wexford, an affiliate of Gulfport. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray and other oil sands development projects. Grizzly has drilled core holes to evaluate the feasibility of oil production in five separate lease blocks but has not commenced development of operations. As of September 30, 2009, Gulfport s net investment in Grizzly was $24,536,000. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was increased by $1,913,000 and $3,053,000 as a result of a currency translation gain for the three months and nine months ended September 30, 2009, respectively. The Company recognized a loss on equity investment of $112,000 and $398,000 for the three months and nine months ended September 30, 2009, respectively, and $217,000 and $526,000 for the three months and nine months ended September 30, 2008, respectively, which is included in other income (expense) in the consolidated statements of operations.

The Company, through its wholly owned subsidiary Grizzly Holdings Inc., entered into a loan agreement with Grizzly effective January 1, 2008, under which Grizzly may borrow funds from the Company. Borrowed funds bear interest at LIBOR plus 400 basis points. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan matures on December 31, 2012. The Company loaned Grizzly approximately $3,451,000 during the nine months ended September 30, 2009. The Company recognized interest income of approximately $152,000 and $380,000 for the three months and nine months ended September 30, 2009, respectively, and $156,000 and $290,000 for the three months and nine months ended September 30, 2008, respectively, which is included in interest income in the consolidated statements of operations. The note balance was increased by approximately $1,083,000 and $1,513,000 as a result of a currency translation gain for the three months and nine months ended September 30, 2009. The total $14,497,000 due from Grizzly at September 30, 2009 is included in note receivable related party on the accompanying consolidated balance sheets.

4. OTHER ASSETS

Other assets consist of the following as of September 30, 2009 and December 31, 2008:

	September 30, 2009	December 31, 2008
Plugging and abandonment escrow account on the WCBB properties (Note 10)	$ 3,136,000	$ 3,144,000
Certificates of deposit securing letter of credit	200,000	200,000
Prepaid drilling costs	151,000	407,000
Deposits	4,000	4,000
	$ 3,491,000	$ 3,755,000

5. LONG-TERM DEBT

A breakdown of long-term debt as of September 30, 2009 and December 31, 2008 is as follows:

	September 30, 2009	December 31, 2008
Reducing credit agreement (1)	$ 45,000,000	$ 64,521,000
Term loans (1)	8,080,000	3,588,000
Building loans (2)	2,548,000	2,622,000
Less: current maturities of long term debt	(50,841,000)	(815,000)
Debt reflected as long term	$ 4,787,000	$ 69,916,000

Maturities of long-term debt as of September 30, 2009 are as follows:

2010	$ 50,841,000
2011	3,157,000

2012	714,000
2013	714,000
2014	202,000
Thereafter	
Total	$ 55,628,000

(1) On March 11, 2005, Gulfport entered into a three-year secured revolving credit agreement providing for a $30.0 million revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility was increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. On December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. The borrowing base is subject to annual and semi-annual redetermination. On August 31, 2009, the lender completed its periodic redetermination of the Company s borrowing base giving consideration to the Company s year-end 2008 and mid-year 2009 reserve information and current bank pricing decks, among other factors. As a result of this redetermination, the Company s available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices during the last eight months. The outstanding balance at the time of redetermination was approximately $59.0 million. The approximately $14.0 million of outstanding borrowings under the credit facility in excess of the new borrowing base were converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and the Company agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010, the maturity date of the credit facility. Outstanding borrowings under the term loan accrue interest at the Eurodollar Rate (as defined in the credit agreement) plus 4% (4.25% at September 30, 2009) or, at the Company s option, at the base rate (which is the highest of the Lender s prime rate, the Federal funds rate plus $^{1}/_{2}$ of 1%, and the one-month Eurodollar Rate plus 1%) plus 3%. As of September 30, 2009, approximately $5.0 million was outstanding under the term loan, which is included in current maturities of long-term debt on the accompanying consolidated balance sheet.

Effective August 31, 2009, the Company agreed to adjustments in the commitment fees, interest rates for revolving loans and fees for letters of credit under the credit facility. Specifically, the Company agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on the Company s utilization percentage.

The Company makes quarterly interest payments on amounts borrowed under the revolving credit facility. At September 30, 2009, amounts borrowed under the credit facility bore interest at 3.75% (the Eurodollar rate plus 3.50%). The Company s obligations under the credit facility are collateralized by a lien on substantially all of the Company s Louisiana and West Texas assets. The credit facility contains certain affirmative and negative covenants, including, but not limited to, the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve month period may not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. In addition, the Company has agreed to limitations on certain dispositions and investments and to mandatory prepayments from the net cash proceeds of specified asset sales and other events. The Company was in compliance with all covenants at September 30, 2009. As of September 30, 2009, $45.0 million was outstanding under this facility, which is included in current maturities of long-term debt on the accompanying consolidated balance sheet.

As noted above, the Company s revolving credit facility currently matures in March 2010. As the Company has historically, it continues to make all interest payments on time and since December 2008, has made principal payments of approximately $39.5 million on its revolving credit facility. The Company intends to renew this revolving credit facility. Although Gulfport has had preliminary discussions with its lender regarding a renewal and maturity date extension of its revolving credit facility beyond March 31, 2010 and the lender has indicated a willingness to renew and extend the maturity date, no definitive agreement has been reached with respect to a renewal and maturity date extension, applicable interest rate(s), number of lenders involved or other specific terms. If discussions with the Company s lender are prolonged or unsuccessful, the Company will be required to obtain funds through different banking relationships, offerings of debt or equity securities and/or other means, including the sale of assets.

On July 10, 2006, Gulfport entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. The Company makes quarterly principal payments of approximately $176,000. Amounts borrowed bear interest at Bank of America prime (3.25% at September 30, 2009). The Company makes quarterly interest payments on amounts borrowed under the agreement. The Company s obligations under the agreement are collateralized by a lien on the compressor units. As of September 30, 2009, approximately $3.1 million was outstanding under this agreement, of which $714,000 and $2.3 million are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on the accompanying consolidated balance sheet.

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(2) In June 2004, the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is collateralized by the Oklahoma City office building and associated land.

6. STOCK-BASED COMPENSATION

During the three months and nine months ended September 30, 2009, the Company s stock-based compensation expense was $98,000 and $428,000, respectively, of which the Company capitalized $39,000 and $171,000, respectively, relating to its exploration and development efforts. During the three months and nine months ended September 30, 2008, the Company s stock based compensation expense was $266,000 and $816,000, respectively, of which the Company capitalized $106,000 and $326,000, respectively, relating to its exploration and development efforts. Stock based compensation included in general and administrative expense reduced basic and diluted earnings per share by $0.00 and $0.01 each for the three months and nine months ended September 30, 2009, respectively, and by $0.00 and $0.01 each for the three months and nine months ended September 30, 2008, respectively. Options and restricted common stock are reported as share based payments and their fair value is amortized to expense using the straight-line method over the vesting period. The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model that uses certain assumptions. Expected volatilities are based on the historical volatility of the market price of Gulfport s common stock over a period of time ending on the grant date. Based upon historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The 2005 Stock Incentive Plan provides that all options must have an exercise price not less than the fair value of the Company s common stock on the date of the grant.

No stock options were issued during the nine months ended September 30, 2009 and 2008.

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. In each case, the actual value that will be realized, if any, depends on the future performance of the common stock and overall stock market conditions. There is no assurance that the value an optionee actually realizes will be at or near the value estimated using the Black-Scholes model.

A summary of the status of stock options and related activity for the nine months ended September 30, 2009 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Options outstanding at December 31, 2008	522,380	$ 7.01	6.24	$ (1,599,000)
Granted				
Exercised	(13,750)	2.20		
Forfeited/expired				
Options outstanding at September 30, 2009	508,630	$ 7.14	5.61	$ 814,000
Options exercisable at September 30, 2009	404,509	$ 8.11	5.69	$ 253,000

Unrecognized compensation expense as of September 30, 2009 related to outstanding stock options and restricted shares was $370,000. The expense is expected to be recognized over a weighted average period of 1.55 years.

The following table summarizes information about the stock options outstanding at September 30, 2009:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$2.00	11,500	0.10	11,500
$3.36	232,241	5.31	128,120
$9.07	64,889	5.94	64,889
$11.20	200,000	6.17	200,000
	508,630		404,509

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The following table summarizes restricted stock activity for the nine months ended September 30, 2009:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2008	93,456	$ 7.04
Granted		
Vested	(34,739)	8.57
Forfeited	(3,086)	15.77
Unvested shares as of September 30, 2009	55,631	$ 5.60

7. EARNINGS PER SHARE

A reconciliation of the components of basic and diluted net income per common share is presented in the table below:

	For the three months ended September 30,					
	2009			2008		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 6,674,000	42,673,800	$ 0.16	$ 14,107,000	42,620,332	$ 0.33
Effect of dilutive securities:						
Stock options and awards		347,957			441,499	
Diluted:						
Net income	$ 6,674,000	43,021,757	$ 0.16	$ 14,107,000	43,061,831	$ 0.33

	For the nine months ended September 30,					
	2009			2008		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 14,485,000	42,660,118	$ 0.34	$ 40,499,000	42,589,277	$ 0.95
Effect of dilutive securities:						
Stock options and awards		320,955			472,106	
Diluted:						
Net income	$ 14,485,000	42,981,073	$ 0.34	$ 40,499,000	43,061,383	$ 0.94

Options to purchase 64,889 shares at $9.07 per share and 200,000 shares at $11.20 per share were excluded from the calculation of dilutive earnings per share for the three months and nine months ended September 30, 2009 because they were anti-dilutive. There were no potential shares of common stock that were considered anti-dilutive during the three month and nine month periods ended September 30, 2008.

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8. OTHER COMPREHENSIVE INCOME

Other comprehensive income for the three months and nine months ended September 30, 2009 and 2008 is as follows:

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net income	$ 6,674,000	$ 14,107,000	$ 14,485,000	$ 40,499,000
Other comprehensive income (loss):				
Change in fair value of derivative instruments	5,895,000		(9,693,000)	
Reclassification of settled contracts	(1,180,000)		(4,962,000)	
Foreign currency translation adjustment	2,996,000	(1,388,000)	4,566,000	(2,349,000)
Total comprehensive income	$ 14,385,000	$ 12,719,000	$ 4,396,000	$ 38,150,000

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9. NEW ACCOUNTING STANDARDS

In June 2009, the FASB issued the FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (the Codification). The Codification became the single official source of authoritative, nongovernmental U.S. generally accepted accounting principles (GAAP). The Codification did not change GAAP but reorganizes the literature. The Codification is effective for interim and annual periods ending after September 15, 2009. There was no impact on the Company s financial condition or results of operations as a result of the Codification.

Effective January 1, 2008, the Company implemented FASB SFAS No. 157 (currently codified in FASB ASC Topic 820, *Fair Value Measurements and Disclosures)* (FASB ASC 820), which defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. The Company elected to implement this statement with the permitted one-year deferral for nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed on a recurring basis. The deferral applied to nonfinancial assets and liabilities measured at fair value in a business combination, impaired properties, plants and equipment, intangible assets and goodwill, and initial recognition of asset retirement obligations and restructuring costs for which fair value is used. The adoption of the provisions of FASB ASC 820 did not have a material impact on the Company s consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007) (currently codified in FASB ASC Topic 805, *Business Combinations*) (FASB ASC 805). FASB ASC 805 establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. FASB ASC 805 also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. FASB ASC 805 is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008. The adoption did not have an immediate impact on the Company s consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160 (currently codified in FASB ASC Topic 810, *Consolidation*) (FASB ASC 810) , which requires that accounting and reporting for minority interest will be recharacterized as noncontrolling interest and classified as a component of equity. FASB ASC 810 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interest of the parent and the interests of the noncontrolling owners. FASB ASC 810 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008. The Company adopted FASB ASC 810 as of January 1, 2009. The adoption did not have a material impact on the Company s consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161 (currently codified in FASB ASC Topic 815, *Derivatives and Hedging)* (FASB ASC 815), which requires enhanced disclosures for derivative and hedging activities, including (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB ASC 815 and related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company adopted FASB ASC 815 as of January 1, 2009. The adoption did not have a material impact on the Company s financial position or results of operations.

In November 2008, the FASB ratified the consensus reached in EITF 08-06 (currently codified in FASB ASC Topic 323, *Investments-Equity Method and Joint Ventures*) (FASB ASC 323). FASB ASC 323 was issued to address questions that arose regarding the application of the equity method subsequent to the issuance of FASB ASC 805. FASB ASC 323 concluded that the equity method investments should continue to be recognized using a cost accumulation model, thus continuing to include transaction costs in the carrying amount of the equity method investment. In addition, FASB ASC 323 clarifies that an impairment assessment should be applied to the equity method investment as a whole, rather than to the individual assets underlying the investment. FASB ASC 323 is effective for fiscal years beginning on or after December 15, 2008. The Company adopted FASB ASC 323 as of January 1, 2009. The adoption did not have a material impact to the Company s financial position or results of operations.

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting*. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12 month period rather than year end prices. The use of average prices will impact future impairment and depletion calculations. The new requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted in quarterly reports prior to the first annual report in which the revised disclosures are required. The Company is currently assessing the impact of this Final Rule.

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In May 2009, the FASB issued SFAS No. 165 (currently codified in FASB ASC Topic 855, *Subsequent Events*) (FASB ASC 855), which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This statement is effective for interim or annual periods ending after June 15, 2009. The adoption of FASB ASC 855 did not have a material impact to the Company s financial position or results of operations. As of November 6, 2009, which is the date these financial statements were issued, the Company completed its review and analysis of potential subsequent events and none were identified.

10. COMMITMENTS AND CONTINGENCIES

Plugging and Abandonment Funds

In connection with its acquisition in 1997 of the remaining 50% interest in the WCBB properties, the Company assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. As of March 11, 2009, the Company became able to access the trust for use in plugging and abandonment charges associated with the property. As of September 30, 2009, the plugging and abandonment trust totaled approximately $3,136,000. The Company has plugged 273 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Litigation

The Louisiana Department of Revenue (LDR) is disputing Gulfport s severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 to 2007. The LDR maintains that Gulfport paid approximately $1,800,000 less in severance taxes under fixed price terms than the severance taxes Gulfport would have had to pay had it paid severance taxes on the oil at the contracted market rates only. Gulfport has denied any liability to the LDR for underpayment of severance taxes and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. Gulfport has maintained its right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against Gulfport seeking $2,275,729 in severance taxes, plus interest and court costs. Gulfport filed a response denying any liability to the LDR for underpayment of severance taxes and is defending itself in the lawsuit. The case is in the early stages of discovery.

In November 2006, Cudd Pressure Control, Inc. (Cudd) filed a lawsuit against Gulfport and Great White Pressure Control LLC, its affiliate, among others, in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleges RICO violations and several other causes of action relating to an affiliate company s employment of several former Cudd employees and seeks unspecified monetary damages and injunctive relief. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Great White Pressure Control LLC, and Gulfport. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Gulfport filed a motion for summary judgment on October 5, 2007. The court entered a final interlocutory judgment in favor of all defendants, including Gulfport, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was recently remanded back to the district court, and Cudd filed a motion to remand the case to state court, which is currently pending. Gulfport also filed a motion for reconsideration on its motion to dismiss for lack of personal jurisdiction, which is also pending. On October 8, 2009, counsel for Gulfport appeared with all parties at a status conference with the court to determine pre-trial deadlines. Among other things, the court ordered that discovery be completed by October 31, 2010 and all motions be filed by November 30, 2010. A trial date will be selected after these deadlines pass.

On July 27, 2007, Robotti & Company, LLC filed a putative class action lawsuit in the Court of Chancery for the State of Delaware. The original complaint alleged a breach of fiduciary duty by Gulfport and its then present directors in connection with the pricing of Gulfport s 2004 rights offering. Plaintiff filed an amended complaint on January 15, 2008, and Gulfport filed a motion to dismiss in early February 2008 and filed the brief in support of such motion on April 29, 2008. The court held a hearing on October 3, 2008, ultimately deciding to allow the plaintiff to file a second amended complaint. Plaintiff filed its second amended complaint December 22, 2008, which sets forth class action and derivative claim allegations that Gulfport s then present directors breached their fiduciary duty in connection with the pricing of the 2004 rights offering. The defendants filed their motion to dismiss on January 19, 2009 and their brief in support of such motion on February 20, 2009. Briefing by the parties concluded April 6, 2009, oral arguments on the motion were heard by the court on April 22, 2009 and the court s ruling on the defendants motion to dismiss is pending.

Due to the current stages of the above litigation, the outcomes are uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse effect on the Company s financial condition or results of operations.

In addition to the above, the Company has been named as a defendant in various other litigation matters. The ultimate resolution of these matters is not expected to have a material adverse effect on the Company s financial condition or results of operations.

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11. INSURANCE PROCEEDS

In March 2009, the Company received insurance proceeds of approximately $1,050,000 related to damages incurred in its WCBB field as a result of Hurricane Ike in 2008. The costs associated with repairing the field were expensed to lease operating expenses as incurred in 2008 and 2009. The Company recognized the insurance proceeds in other (income) expense in the accompanying consolidated statements of operations. In September 2009, the Company received additional insurance proceeds of approximately $795,000 related to damages incurred in the WCBB field as a result of Hurricane Ike and related debris removal. As the costs related to these repairs and debris removal were incurred in 2009 and expensed to lease operating expense, the Company recognized the insurance proceeds in lease operating expenses in the accompanying statements of operations.

12. HEDGING ACTIVITIES

The Company seeks to reduce its exposure to unfavorable changes in oil prices, which are subject to significant and often volatile fluctuation, by entering into forward sales contracts. These contracts allow the Company to predict with greater certainty the effective oil prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

The Company accounts for its oil derivative instruments as cash flow hedges for accounting purposes under FASB ASC 815 and related pronouncements. All derivative contracts are marked to market each quarter end and are included in the accompanying consolidated balance sheets as derivative assets and liabilities.

At September 30, 2009, the fair value of derivative liabilities related to the forward sales contracts is as follows:

Short-term derivative instruments liability	$ 11,800,000
Long-term derivative instruments liability	$ 2,856,000

All forward sales contracts have been executed in connection with the Company s oil price hedging program. For forward sales contracts qualifying as cash flow hedges pursuant to FASB ASC 815, the realized contract price is included in oil sales in the period for which the underlying production was hedged.

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company did not recognize into earnings any amount related to hedge ineffectiveness for the three months and nine months ended September 30, 2009 as the hedges were deemed to be perfectly effective.

During the first quarter of 2009, the Company entered into forward sales contracts with the purchaser of the Company s WCBB oil. The Company receives the fixed price amount stated in the contract for the specified volumes. At September 30, 2009, the Company had the following forward sales contracts in place:

	Daily Volume (Bbls/day)	Weighted Average Price
October - December 2009	3,000	$ 54.81
January - February 2010	3,000	$ 54.81
March - December 2010	2,300	$ 58.24

In the first quarter of 2009, the Company terminated forward sales contracts for 3,000 barrels per day of March 2009 production for approximately $1.5 million and terminated forward sales contracts for 3,000 barrels per day in the second quarter of 2009 for $476,000. For the nine months ended September 30, 2009, approximately $2.0 million related to such terminations is included in oil and condensate sales on the accompanying consolidated statements of operations.

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13. FAIR VALUE MEASUREMENTS

The Company adopted FASB ASC 820 for all financial assets and liabilities measured at fair value on a recurring basis. The Company adopted FASB ASC 820 effective January 1, 2009 for all non-financial assets and liabilities. FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 Quoted prices in active markets for identical assets and liabilities.

Level 2 Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 Significant inputs to the valuation model are unobservable.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The following table summarizes the Company s financial and nonfinancial assets and liabilities by SFAS No. 157 valuation level as of September 30, 2009:

	Level 1	**Level 2**	**Level 3**
Assets:			
Forward sales contracts	$	$	$
Liabilities:			
Forward sales contracts	$	$ 14,656,000	$

The estimated fair value of the Company s forward sales contracts was based upon forward commodity prices based on quoted market prices, adjusted for differentials.

The Company estimates asset retirement obligations pursuant to the provisions of SFAS No. 146 (currently codified in FASB ASC Topic 410, *Asset Retirement and Environmental Obligations*) (FASB ASC 410). 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. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 2 for further discussion of the Company s asset retirement obligations. Asset retirement obligations incurred during the nine months ended September 30, 2009 were approximately $224,000.

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current and long-term debt are carried at cost, which approximates market value.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the Management s Discussion and Analysis of Financial Condition and Results of Operations section and audited consolidated financial statements and related notes thereto included in our Annual Report on Form 10-K and with the unaudited consolidated financial statements and related notes thereto presented in this Quarterly Report on Form 10-Q.

Disclosure Regarding Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements other than statements of historical facts included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, general economic, market or business conditions; the opportunities (or lack thereof) that may be presented to and pursued by us; competitive actions by other oil and natural gas companies; changes in laws or regulations; hurricanes and other natural disasters and other factors, including those listed in the Risk Factors section of our most recent Annual Report on Form 10-K, many of which are beyond our control. Consequently, all of the forward-looking statements made in this report are qualified by these cautionary statements, and we cannot assure you that the actual results or developments anticipated by us will be realized or, even if realized, that they will have the expected consequences to or effects on us, our business or operations. We have no intention, and disclaim any obligation, to update or revise any forward-looking statements, whether as a result of new information, future results or otherwise.

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

Third Quarter 2009 Operational Highlights

- Oil and natural gas revenues decreased 40% to $22.2 million for the three months ended September 30, 2009 from $36.9 million for the three months ended September 30, 2008.
- Net income decreased 53% to $6.7 million for the three months ended September 30, 2009 from $14.1million for the three months ended September 30, 2008.
- Production increased 4% to 416,000 barrels of oil equivalent, or BOE, for the three months ended September 30, 2009 from 400,000 BOE for the three months ended September 30, 2008.
- During the three months ended September 30, 2009, we drilled ten wells and recompleted 18 wells.
- We sold 5,721 net acres in the Bakken for $5.8 million with an effective date of July 1, 2009.

2009 Production and Drilling Activity

During the three months ended September 30, 2009, our total net production was 373,000 barrels of oil, 161,000 thousand cubic feet of gas, or Mcf, and 651,000 gallons of liquids, for a total 416,000 BOE, compared to 361,000 barrels of oil, 135,000 Mcf of gas, and 695,000 gallons of liquids, or 400,000 BOE, for the three months ended September 30, 2008. Our total net production averaged approximately 4,519 BOE per day during the three months ended September 30, 2009 as compared to 4,352 BOE per day during the same period in 2008. The 4% percent increase in production is primarily related to the June 1, 2009 commencement of drilling activities in our WCBB field partially reduced by the sale of production in the Bakken.

WCBB. From January 1, 2009 through November 1, 2009, we recompleted 43 wells and drilled 11 WCBB wells with ten of the 11 completed as producers. We intend to recomplete a total of approximately 50 existing wells during 2009.

Aggregate net production from the WCBB field during the three months ended September 30, 2009 was 322,700 BOE, or 3,507 BOE per day, 95% of which was from oil. During October 2009, our average daily net production at WCBB was approximately 3,544 BOE, 97% of which was from oil and 3% which was from natural gas. The increase in October production is primarily due to the completion of two WCBB wells during late September and October 2009.

East Hackberry Field. From January 1, 2009 through November 1, 2009, we recompleted five existing wells and drilled two wells, one of which is awaiting completion. Currently, we are drilling our third well and intend to drill two or three additional wells during 2009. We entered into a two year exploration agreement with an active gulf coast operator covering approximately 3,058 net acres adjacent to our field. We are the designated operator under the agreement and will participate in proposed wells with at least a 70% working interest. We have licensed approximately 54 square miles of 3-D seismic data covering a portion of the area and are reprocessing the data.

Aggregate net production from the East Hackberry field during the three months ended September 30, 2009 was approximately 27,600 BOE, or 301 BOE per day, 96% of which was from oil and 4% of which was from natural gas. During October 2009, our average daily net production at East Hackberry was approximately 572 BOE, 94% of which was from oil and 6% of which was from natural gas. The increase in October 2009 production is due to the completion of a new well during October 2009 and resumed production from two of our producing wells required to shut in for drilling activities in the field.

West Hackberry Field. Aggregate net production from the West Hackberry field during the three months ended September 30, 2009 was approximately 4,300 BOE, or 47 BOE per day. During October 2009, our average daily net production at West Hackberry was approximately 51 BOE, 100% of which was from oil.

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West Texas. On December 20, 2007, we completed the acquisition of 4,100 net acres and 32 producing wells in West Texas in the Permian Basin for approximately $83.8 million, with an effective date of November 1, 2007. In 2008, 31 gross (15.5 net) wells were drilled on this acreage, including one gross well spud in 2007 and completed in 2008 and one Henry Petroleum operated well. Subsequently, we have acquired an additional 4,095 net acres, bringing our total acreage position to 8,405 net acres. We recently drilled one gross well and anticipate drilling three to four more gross wells during 2009. In addition, we have recompleted two gross wells and intend to recomplete an additional two gross wells on this acreage during 2009.

Aggregate net production from the Permian field during the three months ended September 30, 2009 was approximately 51,600 BOE, or 561 BOE per day. During October 2009, average daily net production at Permian was approximately 567 BOE, of which approximately 54% was oil, 28% was natural gas liquids and 18% was natural gas.

Bakken. During May 2009, we sold approximately 12,270 net acres and approximately 190 net BOEPD of production for approximately $13.0 million, with an effective date of April 1, 2009. During September 2009, we sold approximately 5,721 net acres for $5.8 million with an effective date of July 1, 2009. As of November 1, 2009, we hold approximately 900 net acres, interests in four wells and an overriding royalty interest in certain wells that might be drilled in the future.

Aggregate net production from the Bakken play during the three months ended September 30, 2009 was approximately 9,300 BOE, or 101 BOE per day. During October 2009, average daily net production in Bakken was approximately 91 BOE. This decrease in production was primarily the result of normal production declines.

Grizzly. During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oil Sands ULC, or Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford Capital LP, or Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 527,000 acres under lease and our net investment in Grizzly was $24.5 million at September 30, 2009. In addition, we have loaned Grizzly $14.5 million including interest and net of foreign currency adjustments as of September 30, 2009. During the 2006/2007, 2007/2008 and 2008/2009 winter delineation drilling seasons, Grizzly drilled an aggregate of 131 core holes and one water supply test well, tested five separate lease blocks and conducted a seismic program.

Thailand. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex, at a cost of $2.4 million. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During the nine months ended September 30, 2009, we received $317,000 in distributions and paid $320,000 in cash calls, bringing our total net investment in Tatex (including previous investments) to $2.7 million. Our investment is accounted for on the equity method. Tatex accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm s initial gross production was approximately 60 million cubic feet, or MMcf, per day. Gross production during 2008 was approximately 83 MMcf and 433 Bbls of oil per day. Hess Corporation operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTTEP (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex as a member of APICO) in the Phu Horm field is 0.7%. Estimated proved reserves from the Phu Horm field as of December 31, 2007, net to our interest, are 3.5 BCF of gas and 19,000 barrels of oil. Due to the fact that our ownership in the Phu Horm field is indirect and Tatex s investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

During the first quarter of 2008, we purchased a 5% ownership interest in Tatex Thailand III, LLC, or Tatex III, at a cost of $850,000. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford, an affiliate of ours. Tatex III owns a concession covering one million acres. The operator is currently conducting a 3-D seismic survey on this concession. During the nine months ended September 30, 2009, we paid $390,000 in cash calls bringing our total investment in Tatex III to $1.2 million.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $17.0 million at September 30, 2009 and $22.5 million at December 31, 2008. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids continue to decrease, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations.

Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.

We account for abandonment and restoration liabilities under FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

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The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Pinnacle Energy Services, LLC and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2008 on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the following:

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

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (a) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (b) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2008, a valuation allowance of $81.9 million had been provided for deferred tax assets based on the uncertainty of future taxable income.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments have not significantly deviated from our accruals.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. We are involved in certain litigation for which the outcome is uncertain. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of FASB ASC 815, *Derivatives and Hedging.* It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

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The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings. We currently have forward sales contracts in place for the remainder of 2009 and 2010 that are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended September 30, 2009 and 2008

We reported net income of $6,674,000 for the three months ended September 30, 2009, as compared to $14,107,000 for the three months ended September 30, 2008. This 53% decrease in period-to-period net income was due primarily to a 42% decrease in realized BOE prices to $53.34 from $92.19, partially offset by a 4% increase in net production to 416,000 BOE, a 46% decrease in lease operating expenses, a 21% decrease in general and administrative expenses and a 35% decrease in production taxes.

Oil and Gas Revenues. For the three months ended September 30, 2009, we reported oil and natural gas revenues of $22,173,000 as compared to oil and natural gas revenues of $36,907,000 during the same period in 2008. This $14,734,000, or 40%, decrease in revenues is primarily attributable to a 42% decrease in realized BOE prices to $53.34 from $92.19, partially offset by a 4% increase in net production to 416,000 BOE for the quarter ended September 30, 2009 from 400,000 BOE for the quarter ended September 30, 2008.

The following table summarizes our oil and natural gas production and related pricing for the three months ended September 30, 2009, as compared to such data for the three months ended September 30, 2008:

	Three Months Ended September 30,	
	2009	2008
Oil production volumes (MBbls)	373	361
Gas production volumes (MMcf)	161	135
Liquid production volumes (gallons)	651	695
Oil Equivalents (Mboe)	416	400
Average oil price (per Bbl)	$ 56.62	$ 95.08
Average gas price (per Mcf)	$ 3.09	$ 9.91
Average liquids price (per gallon)	$ 0.82	$ 1.75
Oil equivalents (per Boe)	$ 53.34	$ 92.19

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $3,442,000 for the three months ended September 30, 2009 from $6,362,000 for the same period in 2008. This decrease is mainly a result of a decrease in contract labor expenses, a decrease in workovers, compressor and other equipment rentals and repairs, a decrease in the cost of chemicals and supplies and a decrease in personal property taxes. In addition, the three months ended September 30, 2009 included a net reduction to LOE of $369,000 as a result of insurance reimbursements related to hurricane repairs compared to $666,000 of unreimbursed expenses related to hurricane repairs in the three months ended September 30, 2008.

Production Taxes. Production taxes decreased to $2,586,000 for the three months ended September 30, 2009 from $3,970,000 for the same period in 2008. This decrease was primarily related to a 40% decrease in oil and gas revenues as a result of the decrease in the average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased to $7,387,000 for the three months ended September 30, 2009, and consisted of $7,316,000 in depletion on oil and natural gas properties and $71,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $9,392,000 for the three months ended September 30, 2008. This decrease was due primarily to the reduction in the book value of our oil and gas properties used to calculate depreciation, depletion and amortization expense. This reduction resulted mainly from the drop in commodity prices reflected as of December 31, 2008 and the resulting reduction in our total proved reserves which caused us to recognize a ceiling test impairment of $272,722,000 for the year ended December 31, 2008.

General and Administrative Expenses. Net general and administrative expenses decreased to $1,380,000 for the three months ended September 30, 2009 from $1,748,000 for the same period in 2008. This $368,000 decrease was due primarily to reductions in stock based compensation expenses, reductions in payroll costs including payroll taxes and related benefits mainly due to decreases in the total number of employees, decreases in our franchise taxes, decrease in third party accounting services, and increases in general and administrative reimbursements from our affiliates, partially offset by an increase in legal expenses and a decrease in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $146,000 for the three months ended September 30, 2009 from $140,000 for the same period in 2008.

Interest Expense. Interest expense decreased to $614,000 for the three months ended September 30, 2009 from $1,172,000 for the same period in 2008 due to a decrease in average debt outstanding and lower interest rates on amounts borrowed under our facilities with Bank of America. Total debt outstanding under our facilities with Bank of America was $53.1 million as of September 30, 2009 and $93.3 million as of the same date in 2008. Total weighted debt outstanding under our facilities with Bank of America was $61.5 million for the three months ended September 30, 2009 and $90.8 million for the same period in 2008. As of September 30, 2009, amounts borrowed under our revolving credit facility and our two term loans with Bank of America bore interest of 3.75%, 4.25% and 3.25%, respectively.

Income Taxes. As of September 30, 2009, we had a net operating loss carry forward of approximately $59.5 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At September 30, 2009, a valuation allowance of $81.9 million had been provided for deferred tax assets, with the exception of $653,000 related to alternative minimum taxes. We had no income tax expenses for the three months ended September 30, 2009.

Comparison of the Nine Months Ended September 30, 2009 and 2008

We reported net income of $14,485,000 for the nine months ended September 30, 2009, as compared to $40,499,000 for the nine months ended September 30, 2008. This 64% decrease in period-to-period net income was due primarily to a 40% decrease in realized BOE prices to $49.32 from $82.05 and a 3% decrease in net production to 1,231,000 BOE, partially offset by a 16% decrease in lease operating expenses, a 31% decrease in general and administrative expenses and a 40% decrease in production taxes, In addition, we had $1,050,000 of insurance proceeds received during the nine months ended September 30, 2009 compared to insurance proceeds of $769,000 received during the same period in 2008.

Oil and Gas Revenues. For the nine months ended September 30, 2009, we reported oil and natural gas revenues of $60,692,000 as compared to oil and natural gas revenues of $104,032,000 during the same period in 2008. This $43,340,000, or 42%, decrease in revenues is primarily attributable to a 40% decrease in realized BOE prices to $49.32 from $82.05 and a 3% decrease in net production to 1,231,000 BOE for the nine months ended September 30, 2009 from 1,268,000 BOE for the nine months ended September 30, 2008.

The following table summarizes our oil and natural gas production and related pricing for the nine months ended September 30, 2009, as compared to such data for the nine months ended September 30, 2008:

	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Oil production volumes (MBbls)	1,128	1,132
Gas production volumes (MMcf)	321	559
Liquid production volumes (gallons)	2,075	1,805
Oil Equivalents (Mboe)	1,231	1,268
Average oil price (per Bbl)	$ 51.56	$ 84.50
Average gas price (per Mcf)	$ 3.47	$ 10.04
Average liquids price (per gallon)	$ 0.69	$ 1.54
Oil equivalents (per Boe)	$ 49.32	$ 82.05

Lease Operating Expenses. Lease operating expenses not including production taxes decreased to $12,511,000 for the nine months ended September 30, 2009 from $14,906,000 for the same period in 2008. This decrease is mainly a result of a decrease in contract labor expenses, a decrease in workovers, compressor and other equipment rentals and repairs, a decrease in the cost of chemicals and supplies and a decrease in personal property taxes. In addition, the nine months ended September 30, 2008 included $675,000 of unreimbursed expenses related to hurricane repairs as compared to no unreimbursed expenses related to hurricane repairs in the nine months ended September 30, 2009.

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Production Taxes. Production taxes decreased to $6,856,000 for the nine months ended September 30, 2009 from $11,398,000 for the same period in 2008. This decrease was primarily related to a 42% decrease in oil and gas revenues mainly as a result of the decrease in the average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased to $22,157,000 for the nine months ended September 30, 2009, and consisted of $21,943,000 in depletion on oil and natural gas properties and $214,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $28,912,000 for the nine months ended September 30, 2008. This decrease was due primarily to the reduction in the book value of our oil and gas properties used to calculate depreciation, depletion and amortization expense. This reduction resulted from the drop in commodity prices reflected as of December 31, 2008 and the resulting reduction in our proved reserves which caused us to recognize a ceiling test impairment of $272,722,000 for the year ended December 31, 2008.

General and Administrative Expenses. Net general and administrative expenses decreased to $3,659,000 for the nine months ended September 30, 2009 from $5,270,000 for the same period in 2008. This $1,611,000 decrease was due primarily to reductions in franchise taxes as a result of the impairment mentioned in the depreciation, depletion and amortization section above which reduced our net assets used to calculate franchise taxes, reductions in payroll costs including payroll taxes and related benefits mainly due to decreases in the total number of employees, reduction in stock based compensation expenses, partially offset by a decrease in general and administrative reimbursements from our affiliates and a decrease in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $432,000 for the nine months ended September 30, 2009 from $417,000 for the same period in 2008.

Interest Expense. Interest expense decreased to $1,686,000 for the nine months ended September 30, 2009 from $3,402,000 for the same period in 2008 due to a decrease in average debt outstanding and lower interest rates on amounts borrowed under our facilities with Bank of America. Total debt outstanding under our facilities with Bank of America was $53.1 million as of September 30, 2009 and $93.3 million as of the same date in 2008. Total weighted debt outstanding under our facilities with Bank of America was $62.6 million for the nine months ended September 30, 2009 and $82.0 million for the same period in 2008. As of September 30, 2009, amounts borrowed under our revolving credit facility and our two term loans with Bank of America bore interest of 3.75%, 4.25% and 3.25%, respectively.

Income Taxes. As of September 30, 2009, we had a net operating loss carry forward of approximately $59.5 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At September 30, 2009, a valuation allowance of $81.9 million had been provided for deferred tax assets, with the exception of $653,000 related to alternative minimum taxes. We had $28,000 of state income tax expense for the nine months ended September 30, 2009.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, the issuance of equity securities and borrowings under our bank and other credit facilities. In addition, during 2009, we also received proceeds form the sale of Bakken assets. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and gas production.

Net cash flow provided by operating activities was $35,812,000 for the nine months ended September 30, 2009 as compared to net cash flow provided by operating activities of $75,263,000 for the same period in 2008. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 40% decrease in net realized prices and a 3% decrease in our net BOE production.

Net cash used in investing activities for the nine months ended September 30, 2009 was $19,606,000 as compared to $103,398,000 for the same period in 2008. During the nine months ended September 30, 2009, we spent $33,450,000 in additions to oil and natural gas properties, of which $8,735,000 was spent on our 2009 drilling and recompletion programs, $13,770,000 was spent on expenses attributable to the wells drilled during 2008, $3,670,000 was spent on our 2008 recompletions, $1,175,000 was spent on barges and other facility enhancements, $619,000 was spent on plugging costs and $1,447,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In May and September 2009, we received aggregate net proceeds of approximately $17,694,000 from our sale of properties in the Bakken. In addition, $390,000 was spent on our investment in Tatex III and $3,451,000 was loaned to Grizzly for the nine months ended September 30, 2009. During the nine months ended September 30, 2009, we used cash from operations and proceeds from the sale of Bakken properties to fund our investing activities.

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Net cash used by financing activities for the nine months ended September 30, 2009 was $15,074,000 as compared to net cash provided by financing activities of $29,882,000 for the same period in 2008. The 2009 amount used by financing activities is primarily attributable to payments of $14,500,000 on borrowings under our credit agreement with Bank of America. The 2008 amount provided by financing activities is primarily attributable to borrowings of $30,000,000 under our credit facility with Bank of America and $482,000 from the exercise of stock options.

Credit Facility. In March 2005, we entered into a three-year secured revolving credit agreement, as amended, with Bank of America, N.A providing for a revolving credit facility. Borrowings under the credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. In connection with our acquisition of strategic assets in West Texas in the Permian Basin, effective as of December 20, 2007, our borrowing base under the revolving credit facility increased from $60.0 million to $90.0. In addition, the maturity date was extended from June 30, 2009 to March 31, 2010. On August 31 2009, the lender completed its periodic redetermination of our borrowing base giving consideration to our year-end 2008 and mid-year 2009 reserve information and current bank pricing decks, among other factors. As a result of this redetermination, our available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices during the last eight months. Our outstanding principal balance at the effective time of this redetermination was approximately $59.0 million. Amounts borrowed under the credit facility bear interest at the Eurodollar rate plus 3.50% (3.75% at September 30, 2009). The approximately $14.0 million of outstanding borrowings under our credit facility in excess of the new borrowing base was converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and we agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010, the maturity date of our credit facility. Outstanding borrowings under the term loan accrue interest at the Eurodollar Rate (as defined in the credit agreement) plus 4% (4.25% at September 30, 2009) or, at our option, at the base rate (which is the highest of the lender s prime rate, the Federal funds rate plus 1/2 of 1%, and the one-month Eurodollar Rate plus 1%) plus 3%. Effective August 31, 2009, we also agreed to adjustments in the commitment fees, interest rates for revolving loans and fees for letters of credit under our credit facility. Specifically, we agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on our utilization percentage. In addition, we agreed to limitations on certain dispositions and investments by us, and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events. As of October 31, 2009, the outstanding balance under the term loan had been reduced from $14.0 million to $4.0 million, and our outstanding balance under the revolving credit facility remained at $45.0 million.

We are currently in compliance with all debt covenants and we expect to continue to be in compliance during the balance of 2009. As we have historically, we continue to make all interest payments on time, and as of November 1, 2009, we have made principal payments of approximately $40.5 million on our revolving credit facility and term loan since December 2008. We intend to renew the revolving credit facility. Although we have had preliminary discussions with our lender regarding a renewal and maturity date extension of our revolving credit facility beyond March 31, 2010 and the lender has indicated a willingness to renew and extend the maturity date, no definitive agreement has been reached with respect to a renewal and maturity date extension, applicable interest rate(s), number of lenders involved or other specific terms. If discussions with our lender are prolonged or unsuccessful, we will be required to obtain funds through different banking relationships, offerings of debt or equity securities and/or other means, including the sale of assets. We cannot assure you that such alternative financing sources will be available to us or, if they are available, that they will be on terms favorable to us.

On July 10, 2006, we entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. Amounts borrowed bear interest at Bank of America prime (3.25% at September 30, 2009). We make quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement are collateralized by a lien on the compressor units. As of September 30, 2009, approximately $3.1 million was outstanding under this agreement, of which $714,000 and $2.3 million are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on our accompanying consolidated balance sheet.

Building Loans. In June 2004, we purchased the office building we occupy in Oklahoma City, Oklahoma for $3.7 million. One of the two loans associated with this building, with an original principal amount of $389,000, matured in March 2006 and bore interest at a rate of 6% per annum. The other loan associated with this building, with an original principal amount of $3.0 million, matures in June 2011 and bears interest at a rate of 6.5% per annum. As of September 30, 2009, approximately $2.5 million was outstanding on this loan. The loan requires monthly interest and principal payments and is collateralized by the related land and building.

Capital Expenditures. Our recent capital commitments have been primarily for the development of our proved reserves, to increase our net acreage position in Grizzly and fund Grizzly s delineation drilling program and for acquisitions, primarily our acquisition in the Permian Basin in December 2007. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, and (2) explore acquisition and disposition opportunities. We have upgraded our infrastructure and our existing facilities in Southern Louisiana with the goal of increasing operating efficiencies and volume capacities and lowering lease operating expenses. These upgrades were also intended to better enable our facilities to withstand future hurricanes with less damage. Additionally, we completed the reprocessing of 3-D seismic data in one of our principal properties, WCBB. The reprocessed data enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the field, thus creating a portfolio of new drilling opportunities. In addition, with our acquisition of strategic assets in the Permian Basin in West Texas, we are required to pay 50% of all drilling costs for drilling activity on such properties. To combat significant declines in the commodity prices during the second half of 2008, management undertook a series of actions aimed at reducing capital spending and operating costs. As a result, we reduced our drilling and other capital activities to a minimum in the fourth quarter of 2008, releasing all rigs in Southern Louisiana and the Permian and only selectively participating in wells in the Bakken. During 2009, we are not bound by lease obligations and long term capital commitments relating to the exploration or development of our oil and gas properties. As a result of the then current economic conditions, we initially reduced our estimated capital activities and aggressively sought price concessions from our service providers until such time costs were reduced to more appropriate levels. Currently, our AFE costs have been reduced by 35% to 40% since 2008.

Of our net reserves at December 31, 2008, 67.5% were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

Our inventory of prospects includes approximately 81 drilling locations at WCBB. The drilling schedule used in our December 31, 2008 reserve report anticipates that all of those wells will be drilled by 2019. From January 1, 2009 through November 1, 2009, we drilled 11 wells and recompleted 43 existing wells at our WCBB field. We may recomplete approximately seven additional wells. We currently intend to spend a total of approximately $21.0 to $23.0 million to drill the 11 wells and recomplete approximately 50 wells in our WCBB field during 2009.

In our East Hackberry field, from January 1, 2009 through November 1, 2009, we drilled two wells and recompleted five wells. Currently, we are drilling our third well and intend to drill two to three additional wells during 2009. Total capital expenditures for our East Hackberry field during 2009 are estimated at $9.0 to $10.0 million to drill and recomplete these wells.

In Permian, we have identified 147 gross (73.5 net) future development drilling locations. From January 1, 2009 through November 1, 2009, we drilled one gross well and recompleted two gross existing wells in our Permian field. We are currently drilling our second gross well and currently intend to drill two to three additional gross wells and recomplete an additional two gross wells. We currently anticipate that our capital requirements to drill a total of five gross wells and recomplete four gross wells in the Permian Basin in West Texas will be approximately $6.0 to $8.0 million during 2009.

During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. As of September 30, 2009, our net investment in Grizzly was approximately $24.5 million. Our capital requirements in 2009 for this project are estimated to be approximately $5.0 million, primarily for the expenses associated with the drilling of 15 well core holes, including one water supply test, during Grizzly s 2008/2009 drilling program.

Capital expenditures in 2009 relating to our interest in Thailand are expected to be approximately $1.0 million, which we believe will be mostly offset from our share of production from the Phu Horm field.

Capital expenditures for 2009 activities related to our interest in the Bakken Shale in the Williston Basin are now expected to be approximately $840,000, down from the $2.5 million we anticipated prior to our sale of Bakken properties.

Our total capital expenditures for 2009 are currently estimated to be in the range of $40.0 to $46.0 million. This is down significantly from $95.0 million in 2008 due to the current commodity pricing and cost environment. In response to the challenging economic conditions, we reduced our planned 2009 drilling and other capital activities. In addition, through our cost reduction initiatives, AFE costs have been reduced by 35% to 40% from costs quoted in 2008. We intend to monitor pricing and cost developments and make adjustments to our capital expenditure program as warranted.

We believe that our cash on hand and cash flow from operations will be sufficient to meet our normal recurring operating needs and our WCBB, Hackberry, Permian Basin and Grizzly capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue acquisitions or accelerate our Canadian oil sands project, we would be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. In addition, the revolving credit facility and the term loan under our credit agreement mature in March 2010. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

To mitigate the effects of commodity price fluctuations, during 2008 we were party to forward sales contracts for the sale of 3,500 barrels of WCBB production per day at a weighted average daily price of $78.56 per barrel before transportation costs. We

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delivered approximately 73% of our 2008 production under these agreements. For the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We have also entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs, for the period September 2009 to December 2009. In 2009, we terminated forward sales contracts for the months of March and May 2009 for an aggregate of approximately $2.0 million. Under the remaining 2009 contracts, we have committed to deliver approximately 50% of our estimated 2009 production. For the period January 2010 through February 2010 we have entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs. For the period March 2010 through December 2010, we have entered into forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in March 2009, we became entitled to access the trust for use in plugging and abandonment charges associated with the property if desired. As of September 30, 2009, the plugging and abandonment trust totaled approximately $3,136,000. At September 30, 2009, we had plugged 273 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

New Accounting Pronouncements

For information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, please refer to Note 9 to the accompanying consolidated financial statements.

ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On September 30, 2009, the West Texas Intermediate posted price for crude oil was $70.46 per bbl and the Henry Hub spot market price of natural gas was $3.24 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

To mitigate the effects of commodity price fluctuations, during 2008 we were party to forward sales contracts for the sale of 3,500 barrels of WCBB production per day at a weighted average daily price of $78.56 per barrel before transportation costs. We delivered approximately 73% of our 2008 production under these agreements. For the period January through December 2009, we had entered into agreements to sell

3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We also entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs, for the period September 2009 to December 2009. In 2009, we terminated forward sales contracts for the months of March and May 2009 for an aggregate of approximately $2.0 million. Under the remaining 2009 contracts, we have committed to deliver approximately 50% of our estimated 2009 production. For the period January 2010 through February 2010, we have entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs. For the period March 2010 through December 2010, we have entered into forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Our revolving credit facility and term loans with Bank of America are structured under floating rate terms and, as such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. Borrowings under our revolving credit facility with Bank of America bear interest at the Eurodollar rate plus 3.50% (3.75% at September 30, 2009). Borrowings under our term loan with Bank of America bear interest at the Eurodollar rate plus 4% (4.25% at September 30, 2009). Borrowings under our compressor term loan with Bank of America bear interest at Bank of America prime (3.25% at September 30, 2009). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $744,000 per year, based on an aggregate of $53.1 million outstanding under our credit facilities as of September 30, 2009. As of September 30, 2009, we did not have any interest rate swaps to hedge our interest risks.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and Vice President and Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of September 30, 2009, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of September 30, 2009, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against our company seeking $2,275,729 in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes and are defending our Company in the lawsuit. The case is in the early stages of discovery.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us and Great White Pressure Control LLC, an affiliate of ours, among others, in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleges RICO violations and several other causes of action relating to an affiliate company s employment of several former Cudd employees and seeks unspecified monetary damages and injunctive relief. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Great White Pressure Control LLC, and us. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. We filed a motion for summary judgment on October 5, 2007. The court entered a final interlocutory judgment in favor of all defendants, including us, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was recently remanded back to the district court, and Cudd filed a motion to remand the case to state court, which is currently pending. We also filed a motion for reconsideration on our motion to dismiss for lack of personal jurisdiction, which is also pending. On October 8, 2009, our counsel appeared with all parties at a status conference with the court to determine pre-trial deadlines. Among other things, the court ordered that discovery be completed by October 31, 2010 and all motions be filed by November 30, 2010. A trial date will be selected after these deadlines pass.

On July 27, 2007, Robotti & Company, LLC filed a putative class action lawsuit in the Court of Chancery for the State of Delaware. The original complaint alleged a breach of fiduciary duty by us and our then present directors in connection with the pricing of our 2004 rights offering. Plaintiff filed an amended complaint on January 15, 2008, and we filed a motion to dismiss in early February 2008 and filed the brief in support of such motion on April 29, 2008. The court held a hearing on October 3, 2008, ultimately deciding to allow the plaintiff to file a second amended complaint. Plaintiff filed its second amended complaint December 22, 2008, which sets forth class action and derivative claim allegations that our then present directors breached their fiduciary duty in connection with the pricing of the 2004 rights offering. The defendants filed their motion to dismiss on January 19, 2009 and their brief in support of such motion on February 20, 2009. Briefing by the parties concluded April 6, 2009, oral arguments on the motion were heard by the court on April 22, 2009 and the court s ruling on the defendants motion to dismiss is pending.

Due to the current stages of the above litigation, the outcomes are uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse affect on our financial condition or results of operations.

In addition to the above, we have been named as a defendant in various other lawsuits related to our business. The ultimate resolution of such other matters is not expected to have a material adverse effect on our financial condition or results of operations.

ITEM 1A. RISK FACTORS.

See risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2008.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(a) None

(b) Not Applicable.

(c) We do not have a share repurchase program, and during the three months ended September 30, 2009, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

(a) None.

(b) None.

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2*	Certificate of Amendment No. 1 to Restated Certificate of Incorporation.
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
10.1	Fourth Amendment to Credit Agreement and Limited Waiver, entered into as of August 31, 2009, between the Company, as borrower, each lender from time to time party thereto and Bank of America, N.A., as a lender and administrative agent (incorporated by reference to exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on September 4, 2009).
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.

* Filed herewith.

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SIGNATURES

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

Date: November 6, 2009

GULFPORT ENERGY CORPORATION

/s/ James D. Palm
James D. Palm
Chief Executive Officer

/s/ Michael G. Moore
Michael G. Moore
Chief Financial Officer

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Exhibit Index

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* Filed herewith.