GULFPORT ENERGY CORP
Form 10-Q
November 05, 2010
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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, 2010

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 1, 2010, 44,591,399 shares of common stock were outstanding.

GULFPORT ENERGY CORPORATION

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 2,073,000	$ 1,724,000
Accounts receivable - oil and gas	12,516,000	9,492,000
Accounts receivable - related parties	312,000	136,000
Prepaid expenses and other current assets	1,840,000	2,047,000
Total current assets	16,741,000	13,399,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $27,973,000 and $17,521,000 excluded from amortization in 2010 and 2009, respectively	713,293,000	628,849,000
Other property and equipment	7,512,000	7,182,000
Accumulated depletion, depreciation, amortization and impairment	(500,827,000)	(473,915,000)
Property and equipment, net	219,978,000	162,116,000
Other assets		
Equity investments	31,611,000	32,006,000
Note receivable - related party	19,370,000	15,920,000
Other assets	4,059,000	3,370,000
Total other assets	55,040,000	51,296,000
Deferred tax asset	554,000	533,000
Total assets	$ 292,313,000	$ 227,344,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 34,150,000	$ 20,977,000
Asset retirement obligation - current	635,000	635,000
Short-term derivative instruments	4,100,000	18,735,000
Current maturities of long-term debt	2,446,000	2,842,000
Total current liabilities	41,331,000	43,189,000
Asset retirement obligation - long-term	9,921,000	9,518,000

Long-term debt, net of current maturities	45,700,000	49,586,000
Total liabilities	96,952,000	102,293,000
Commitments and contingencies (Note 13)		
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, 100,000,000 authorized, 44,591,069 issued and outstanding in 2010 and 42,696,409 in 2009	446,000	427,000
Paid-in capital	295,815,000	273,901,000
Accumulated other comprehensive income (loss)	(2,710,000)	(18,039,000)
Retained earnings (accumulated deficit)	(98,190,000)	(131,238,000)
Total stockholders equity	195,361,000	125,051,000
Total liabilities and stockholders equity	$ 292,313,000	$ 227,344,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Revenues:				
Oil and condensate sales	$ 31,558,000	$ 21,142,000	$ 84,853,000	$ 58,146,000
Gas sales	1,061,000	498,000	2,813,000	1,114,000
Natural gas liquids sales	654,000	533,000	1,995,000	1,432,000
Other income (expense)	(92,000)	(102,000)	(250,000)	(323,000)
	33,181,000	22,071,000	89,411,000	60,369,000
Costs and expenses:				
Lease operating expenses	4,063,000	3,442,000	12,212,000	12,511,000
Production taxes	3,657,000	2,586,000	10,390,000	6,856,000
Depreciation, depletion, and amortization	10,299,000	7,387,000	26,912,000	22,157,000
General and administrative	1,538,000	1,380,000	4,438,000	3,659,000
Accretion expense	156,000	146,000	461,000	432,000
	19,713,000	14,941,000	54,413,000	45,615,000
INCOME FROM OPERATIONS:	13,468,000	7,130,000	34,998,000	14,754,000
OTHER (INCOME) EXPENSE:				
Interest expense	823,000	614,000	2,154,000	1,686,000
Insurance proceeds				(1,050,000)
Interest income	(33,000)	(158,000)	(244,000)	(395,000)
	790,000	456,000	1,910,000	241,000
INCOME BEFORE INCOME TAXES	12,678,000	6,674,000	33,088,000	14,513,000
INCOME TAX EXPENSE:			40,000	28,000
NET INCOME	$ 12,678,000	$ 6,674,000	$ 33,048,000	$ 14,485,000
NET INCOME PER COMMON SHARE:				
Basic	$ 0.28	$ 0.16	$ 0.76	$ 0.34
Diluted	$ 0.28	$ 0.16	$ 0.75	$ 0.34

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		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders Equity
	Shares	Amount				
Balance at January 1, 2010	42,696,409	$ 427,000	$ 273,901,000	$ (18,039,000)	$ (131,238,000)	$ 125,051,000
Net income					33,048,000	33,048,000
Other Comprehensive Income:						
Foreign currency translation adjustment				694,000		694,000
Change in fair value of derivative instruments				709,000		709,000
Reclassification of settled contracts				13,926,000		13,926,000
Total Comprehensive Income						48,377,000
Stock Compensation			338,000			338,000
Issuance of Common Stock in public offering, net of related expenses of $204,000	1,668,503	17,000	21,346,000			21,363,000
Issuance of Common Stock through exercise of warrants	172,269	2,000	203,000			205,000
Issuance of Restricted Stock	41,888					
Issuance of Common Stock through exercise of options	12,000		27,000			27,000
Balance at September 30, 2010	44,591,069	$ 446,000	$ 295,815,000	$ (2,710,000)	$ (98,190,000)	$ 195,361,000
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

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, 2010	2009
Cash flows from operating activities:		
Net income	$ 33,048,000	$ 14,485,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount - Asset Retirement Obligation	461,000	432,000
Depletion, depreciation and amortization	26,912,000	22,157,000
Stock-based compensation expense	203,000	257,000
Loss from equity investments	486,000	427,000
Interest income - note receivable	(232,000)	(380,000)
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(3,024,000)	3,335,000
(Increase) decrease in accounts receivable - related party	(176,000)	955,000
Decrease (increase) in prepaid expenses	207,000	(579,000)
Increase in other assets	(711,000)	
Increase (decrease) in accounts payable and accrued liabilities	2,313,000	(5,242,000)
Settlements of asset retirement obligation	(1,253,000)	(35,000)
Net cash provided by operating activities	58,234,000	35,812,000
Cash flows from investing activities:		
Deductions to cash held in escrow	8,000	8,000
Additions to other property, plant and equipment	(330,000)	(14,000)
Additions to oil and gas properties	(72,260,000)	(33,450,000)
Proceeds from sale of oil and gas properties		17,694,000
Note receivable - related party	(2,957,000)	(3,451,000)
Investment in Tatex Thailand II, LLC	565,000	(3,000)
Investment in Tatex Thailand III, LLC	(224,000)	(390,000)
Net cash used in investing activities	(75,198,000)	(19,606,000)
Cash flows from financing activities:		
Principal payments on borrowings	(49,982,000)	(15,103,000)
Borrowings on line of credit	45,700,000	
Proceeds from issuance of common stock, net of offering costs of $204,000, and exercise of stock options	21,595,000	29,000
Net cash provided (used) by financing activities	17,313,000	(15,074,000)
Net increase in cash and cash equivalents	349,000	1,132,000
Cash and cash equivalents at beginning of period	1,724,000	5,944,000

Cash and cash equivalents at end of period	$ 2,073,000	$ 7,076,000
Supplemental disclosure of cash flow information:		
Interest payments	$ 1,564,000	$ 1,561,000
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$ 135,000	$ 171,000
Asset retirement obligation capitalized	$ 1,195,000	$ 224,000
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$ 433,000	$ 3,053,000
Foreign currency translation gain (loss) on note receivable - related party	$ 261,000	$ 1,513,000

See accompanying notes to consolidated financial statements.

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, 2010 are not necessarily indicative of the results expected for the full year.

1. ACQUISITION

On June 15, 2010, Gulfport closed on the acquisition of an ownership interest in certain oil and gas properties located in the Niobrara Shale of Colorado, including approximately 24,468 net acres with three gross producing wells for a cash price of approximately $7.75 million. The effective date of the acquisition was April 1, 2010. The total purchase price for the acquired assets, as adjusted at closing on June 15, 2010, was $7.7 million, which was recorded as oil and natural gas properties on the accompanying September 30, 2010 consolidated balance sheet. This amount includes an adjustment for the results of operations of the assets between the April 1, 2010 effective date and the June 15, 2010 closing date. The Company may adjust the purchase price for any post closing adjustments, scheduled 120 days from the original closing date of June 15, 2010. The results of operations from these properties were included in the September 30, 2010 consolidated statement of operations only for the period subsequent to the closing date, in this case, for the period of June 16, 2010 through September 30, 2010.

During May 2010, Gulfport entered into an agreement to acquire a 50% interest in 4,979 gross (2,489 net) undeveloped acres in the Permian Basin for approximately $7.6 million. Gulfport funded these transactions predominately through a 1.7 million common share offering completed in May of 2010. The Company received net proceeds (before offering expenses) of approximately $21.6 million from the equity offering, as discussed below in Note 7.

2. ACCOUNTS RECEIVABLE RELATED PARTY

Included in the accompanying September 30, 2010 and December 31, 2009 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, 2010 and December 31, 2009, these receivable amounts totaled $312,000 and $136,000, respectively. The Company was reimbursed $101,000 and $593,000 for the three months and nine months ended September 30, 2009 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. No amounts were reimbursed for general and administrative functions for the three months and nine months ended September 30, 2010.

The Company is a party to an administrative service agreement with Great White Energy Services LLC. Under this agreement, the Company s services include 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. The administrative service agreement had an initial three-year term, and currently continues on a month-to-month basis until cancelled by either party to such agreement with at least 30 days prior written notice.

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 these 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 had an initial two-year term, and currently continues on a month-to-month basis until cancelled by either party to such agreement with at least 60 days prior written notice.

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, 2010 and 2009. 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 34% of Gulfport s outstanding common stock.

Agreement Effective Date	Entitye	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
7/22/2006	Great White Energy Services LLC	$	$ 17,000	$	$ 61,000
3/1/2008	Stampede Farms LLC				
3/1/2008	Grizzly Oil Sands ULC		3,000		20,000
3/1/2008	Everest Operations Management LLC		80,000		508,000
3/1/2008	Tatex Thailand III, LLC				

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. For the nine months ended September 30, 2010, the Company was reimbursed approximately $11,000 by Orange Leaf Holdings, LLC, an affiliate of Gulfport, for office space which is included in other income (expense) in the consolidated statements of operations.

Effective July 1, 2008, the Company entered into 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.

Effective April 1, 2010, the Company entered into an area of mutual interest agreement with Windsor Niobrara LLC (Windsor Niobrara), an entity controlled by Wexford, to jointly acquire oil and gas leases on certain lands located in Northwest Colorado for the purpose of exploring, exploiting and producing oil and gas from the Niobrara Shale. The agreement provides that each party must offer the other party the right to participate in such acquisition on a 50%/50% basis. The parties also agreed, subject to certain exceptions, to share third-party costs and expenses in proportion to their respective participating interests and pay certain other fees as provided in the agreement. In connection with this agreement, Gulfport and Windsor Niobrara also entered into a development agreement, effective as of April 1, 2010, pursuant to which the Company and Windsor Niobrara agreed to jointly develop the contract area, and Gulfport agreed to act as the operator under the terms of a joint operating agreement.

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of September 30, 2010 and December 31, 2009 are as follows:

	September 30, 2010	December 31, 2009
Oil and natural gas properties	$ 713,293,000	$ 628,849,000
Office furniture and fixtures	3,180,000	2,996,000
Buildings	4,049,000	3,926,000
Land	283,000	260,000
Total property and equipment	720,805,000	636,031,000
Accumulated depletion, depreciation, amortization and impairment	(500,827,000)	(473,915,000)

Property and equipment, net	$	219,978,000	$	162,116,000

Included in oil and natural gas properties at September 30, 2010 is the cumulative capitalization of $17,025,000 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

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and administrative costs were approximately $1,044,000 and $3,015,000 for the three months and nine months ended September 30, 2010, respectively, and $934,000 and $2,485,000 for the three months and nine months ended September 30, 2009, respectively.

At September 30, 2010, approximately $2,538,000 of oil and natural gas properties related to the Company s Belize properties is excluded from amortization as they relate to non-producing properties. In addition, approximately $22,749,000 of non-producing leasehold costs resulting from the Company s acquisition of West Texas Permian properties, $301,000 of non-producing leasehold costs related to the Company s Bakken properties and $1,396,000 of non-producing leasehold costs related to the Company s Colorado properties are excluded from amortization at September 30, 2010. Approximately $989,000 of non-producing leasehold costs related to the Company s Southern Louisiana assets is also excluded from amortization at September 30, 2010.

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, 2010 and 2009 is as follows:

	September 30, 2010	September 30, 2009
Asset retirement obligation, beginning of period	$ 10,153,000	$ 9,269,000
Liabilities incurred	1,195,000	224,000
Liabilities settled	(1,253,000)	(35,000)
Accretion expense	461,000	432,000
Asset retirement obligation as of end of period	10,556,000	9,890,000
Less current portion	635,000	635,000
Asset retirement obligation, long-term	$ 9,921,000	$ 9,255,000

4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of September 30, 2010 and December 31, 2009.

	September 30, 2010	December 31, 2009
Investment in Tatex Thailand II, LLC	$ 1,918,000	$ 2,485,000
Investment in Tatex Thailand III, LLC	4,557,000	4,482,000
Investment in Grizzly Oil Sands ULC	25,136,000	25,039,000
	$ 31,611,000	$ 32,006,000

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. 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, 2010, Gulfport received $565,000 in distributions, bringing its total investment in Tatex (including previous investments) to $1,918,000. The loss on equity investment related to Tatex was immaterial for the nine months ended September 30, 2010 and 2009, respectively.

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. In December 2009, the Company purchased an additional approximately 12.9% ownership interest at a cost of approximately $3,385,000 bringing its total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. During the nine months ended September 30, 2010, Gulfport paid $224,000 in cash calls, bringing its total investment in Tatex III (including previous investments) to $4,557,000. The Company recognized a loss on equity investment of $149,000 and $29,000 for the nine months ended September 30, 2010 and 2009, respectively, which is included in other income (expense) in the consolidated statements of operations.

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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. 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. In 2010, Grizzly filed an application for construction of an 11,300 barrel per day oil sand project. As of September 30, 2010, Gulfport s net investment in Grizzly was $25,136,000. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was increased by $733,000 and $433,000 as a result of a currency translation gain for the three months and nine months ended September 30, 2010, respectively. The Company recognized a loss on equity investment of $171,000 and $336,000 for the three months and nine months ended September 30, 2010, respectively, and $112,000 and $398,000 for the three months and nine months ended September 30, 2009, 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 initially bore interest at LIBOR plus 400 basis points and had an initial maturity date of December 31, 2012. Effective April 1, 2010, the loan agreement was amended to modify the interest rate to 0.69% and change the maturity date to December 31, 2011. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The Company loaned Grizzly approximately $2,957,000 during the nine months ended September 30, 2010. The Company recognized interest income of approximately $31,000 and $232,000 for the three months and nine months ended September 30, 2010, respectively, and $152,000 and $380,000 for the three months and nine months ended September 30, 2009, respectively, which is included in interest income in the consolidated statements of operations. The note balance was increased by approximately $502,000 and $261,000 as a result of a currency translation gain for the three months and nine months ended September 30, 2010, respectively. The total $19,370,000 due from Grizzly at September 30, 2010 is included in note receivable related party on the accompanying consolidated balance sheets.

5. OTHER ASSETS

Other assets consist of the following as of September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
Plugging and abandonment escrow account on the WCBB properties (Note 13)	$ 3,128,000	$ 3,136,000
Certificates of deposit securing letter of credit	275,000	200,000
Prepaid drilling costs	16,000	30,000
Loan commitment fees	636,000	
Deposits	4,000	4,000
	$ 4,059,000	$ 3,370,000

6. LONG-TERM DEBT

A breakdown of long-term debt as of September 30, 2010 and December 31, 2009 is as follows:

	September 30, 2010	December 31, 2009
Revolving credit agreement (1)	$ 45,700,000	$ 45,000,000
Term loans (1)		4,903,000
Building loans (2)	2,446,000	2,525,000

Less: current maturities of long term debt	(2,446,000)	(2,842,000)
Debt reflected as long term	$ 45,700,000	$ 49,586,000

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Maturities of long-term debt as of September 30, 2010 are as follows:

2011	$ 2,446,000
2012	
2013	45,700,000
2014	
2015	
Thereafter	
Total	$ 48,146,000

(1) On March 11, 2005, Gulfport entered into a three-year secured credit agreement with Bank of America, N.A. providing for a revolving credit facility. The credit agreement was subsequently amended and restated and, among other things, the maturity date was extended until April 1, 2011. Borrowings under the revolving credit facility were subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. Effective July 19, 2007, the credit facility was increased to $150.0 million and effective December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million.

On August 31, 2009, the lender completed its periodic redetermination of the Company s borrowing base giving consideration to year-end 2008 and mid-year 2009 reserve information and then 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. The Company s outstanding principal balance at the effective time of this 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 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 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 Company paid the outstanding balance of the term loan in full in February 2010.

Outstanding borrowings under the term loan accrued interest at the Eurodollar rate (as defined in the credit agreement) plus 4.0% or, at the option of the Company, at the base rate (which was the highest of the lender s prime rate, the Federal funds rate plus half of 1%, and the one-month Eurodollar rate plus 1%) plus 3%. Effective August 31, 2009, the Company also agreed to an adjustment 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. In addition, the Company agreed to limitations on certain dispositions and investments and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

The Company s obligations under the credit facility were collateralized by a lien on substantially all of the Company s Louisiana and West Texas assets and were guaranteed by its subsidiaries. The restated credit agreement contained 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 could not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period could not be less than 3.00 to 1.00.

On September 30, 2010, Gulfport entered into a $100 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association. The new revolving credit facility matures on September 30, 2013 and has an initial borrowing base availability of $50.0 million. As of September 30, 2010, the Company had an outstanding balance of $45.7 million drawn under the credit agreement, which is included in long-term debt, net of current maturities, on the accompanying consolidated balance sheets. The amounts borrowed under the credit agreement were used to repay the Company s outstanding indebtedness under its prior revolving credit facility ($42.0 million) and term loan ($2.5 million), each with Bank of America, N.A., as administrative agent, and to terminate such facilities. The new credit agreement is secured by substantially all of the Company s assets. The

Company s wholly-owned subsidiaries guaranteed the obligations of the Company under the credit agreement.

Advances under the credit agreement may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.75% to 3.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At September 30, 2010, amounts borrowed under the credit agreement bore interest at the base rate (5.75%).

The credit agreement contains customary negative covenants including, but not limited to, restrictions on the Company s and its subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) 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. The Company was in compliance with all covenants at September 30, 2010.

In conjunction with the repayment of the Bank of America credit facilities on September 30, 2010, the Company recognized approximately $225,000 in unamortized loan fees associated with the Bank of America revolving credit facility, which is included in interest expense in the accompanying consolidated statements of operations.

On July 10, 2006, Gulfport entered into a $5 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 made quarterly principal payments of approximately $176,000. Amounts borrowed bore interest at Bank of America Prime. The Company made quarterly interest payments on amounts borrowed under the agreement. The Company s obligations under the agreement were collateralized by a lien on the compressor units. On September 30, 2010, the Company paid this loan in full with borrowings under the new credit agreement discussed above.

(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.

7. COMMON STOCK OPTIONS, RESTRICTED STOCK, WARRANTS AND CHANGES IN CAPITALIZATION

Restricted Stock

On March 8, 2010, the Company granted 66,667 shares of restricted common stock of the Company to employees of the Company at a fair value of approximately $662,000. The shares vest over twelve substantially equal quarterly installments beginning on March 18, 2010. All shares of restricted common stock of the Company were granted under the Amended and Restated 2005 Stock Incentive Plan.

Sale of Common Stock

On May 19, 2010, the Company sold 1,481,481 shares of its common stock in an underwritten public offering at a public offering price of $13.50 per share less the underwriting discount. On May 25, 2010, the Company sold an additional 187,022 shares of common stock at the public offering price less the underwriting discount in connection with the underwriters partial exercise of the over-allotment option granted to them by the Company. The Company received the aggregate net proceeds of approximately $21.6 million from the sale of these shares after deducting the underwriting discount and before offering expenses. A portion of the net proceeds from the offering was used to fund the

Company s Niobrara Shale and Permian Basin acquisitions as discussed in Note 1. The remaining net proceeds from this offering were used for general corporate purposes, including expenditures associated with the Company s 2010 drilling programs.

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8. STOCK-BASED COMPENSATION

During the three months and nine months ended September 30, 2010, the Company s stock-based compensation expense was $105,000 and $338,000, respectively, of which the Company capitalized $42,000 and $135,000, respectively, relating to its exploration and development efforts. 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. Stock based compensation included in general and administrative expense reduced basic and diluted earnings per share by $0.00 and $0.00 each for the three months and nine months ended September 30, 2010, respectively, and by $0.00 and $0.01 each for the three months and nine months ended September 30, 2009, 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, 2010 and 2009.

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, 2010 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2009	508,630	$ 7.14	5.38	$ 2,192,000
Granted				
Exercised	(12,000)	2.23		118,000
Forfeited/expired	(1,500)	2.00		
Options outstanding at September 30, 2010	495,130	$ 7.28	4.74	$ 3,250,000
Options exercisable at September 30, 2010	495,130	$ 7.28	4.74	$ 3,250,000

Unrecognized compensation expense as of September 30, 2010 related to outstanding stock options and restricted shares was $701,000. The expense is expected to be recognized over a weighted average period of 1.58 years.

The following table summarizes information about the stock options outstanding at September 30, 2010:

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Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$2.00		0.00	
$3.36	230,241	4.31	230,241
$9.07	64,889	4.94	64,889
$11.20	200,000	5.17	200,000
	495,130		495,130

The following table summarizes restricted stock activity for the nine months ended September 30, 2010:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2009	60,244	$ 6.01
Granted	66,667	9.93
Vested	(41,888)	7.72
Forfeited		
Unvested shares as of September 30, 2010	85,023	$ 8.24

9. EARNINGS PER SHARE

	For the three months ended September 30,					
	2010			2009		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 12,678,000	44,571,478	$ 0.28	$ 6,674,000	42,673,800	$ 0.16
Effect of dilutive securities:						
Stock options and awards		301,628			347,957	
Diluted:						
Net income	$ 12,678,000	44,873,106	$ 0.28	$ 6,674,000	43,021,757	$ 0.16

	For the nine months ended September 30,					
	2010			2009		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 33,048,000	43,612,468	$ 0.76	$ 14,485,000	42,660,118	$ 0.34

Effect of dilutive securities:						
Stock options and awards		364,797			320,955	
Diluted:						
Net income	$ 33,048,000	43,977,265	$ 0.75	$ 14,485,000	42,981,073	$ 0.34

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, 2010.

10. OTHER COMPREHENSIVE INCOME

Other comprehensive income for the three months and nine months ended September 30, 2010 and 2009 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Net income	$ 12,678,000	$ 6,674,000	$ 33,048,000	$ 14,485,000
Other comprehensive income (loss):				
Change in fair value of derivative instruments	(2,251,000)	5,895,000	709,000	(9,693,000)
Reclassification of settled contracts	4,548,000	(1,180,000)	13,926,000	(4,962,000)
Foreign currency translation adjustment	1,235,000	2,996,000	694,000	4,566,000
Total comprehensive income	$ 16,210,000	$ 14,385,000	$ 48,377,000	$ 4,396,000

11. NEW ACCOUNTING STANDARDS

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, *Improving Disclosures about Fair Value Measurements,* which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosure* (FASB ASC 820). FASB ASC 820 requires additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) significant transfers between Levels 1, 2 and 3. The updated guidance is effective for annual and interim periods beginning after December 15, 2009. The Company adopted FASB ASC 820 effective January 1, 2010. The adoption did not have a material impact on the Company s consolidated financial statements.

12. OPERATING LEASES

In October 2006, the Company began leasing the Louisiana building that it owns to an unrelated party. The cost of the building totaled approximately $217,000 and accumulated depreciation amounted to approximately $95,000 as of September 30, 2010. The lease commenced on October 15, 2006 and was extended to expire on October 14, 2010, with equal monthly installments of $10,500. The future lease payments due during the fiscal year ending December 31, 2010 are approximately $5,000.

13. COMMITMENTS AND CONTINGENCIES

Plugging and Abandonment Funds

In connection with the 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. Beginning in 2009, the Company can access the trust for use in plugging and abandonment charges associated with the property. As of September 30, 2010, the plugging and abandonment trust totaled approximately $3,128,000. At September 30, 2010, the Company has plugged 311 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, Great White Pressure Control LLC (Great White) and six former Cudd employees 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 alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. 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 remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that Gulfport conspired with the other defendants to misappropriate, and misappropriated, Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, Gulfport s motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages.

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.

14. 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 consolidated statements of operations.

15. 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, 2010 and December 31, 2009, the fair value of derivative assets and liabilities related to the forward sales contracts is as follows:

	September 30, 2010	December 31, 2009
Short-term derivative instruments liability	$ 4,100,000	$ 18,735,000

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, 2010 and 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. At September 30, 2010, the Company had the following forward sales contracts in place:

	Daily Volume (Bbls/day)	Weighted Average Price
October - December 2010	2,300	$ 58.24

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16. 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 FASB ASC 820 valuation level as of September 30, 2010:

	Level 1	Level 2	Level 3
Assets:			
Forward sales contracts	$	$	$
Liabilities:			
Forward sales contracts	$	$ 4,100,000	$

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 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 3 for further discussion of the Company s asset retirement obligations. Asset retirement obligations incurred during the nine months ended September 30, 2010 were approximately $1,195,000.

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.

17. SUBSEQUENT EVENTS

In November 2010, the Company entered into forward sales contracts for 2,000 barrels of oil per day for 2011 at a weighted average price of $86.96 per barrel, before transportation costs and differentials.

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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 recently acquired an acreage position in Western Colorado in the Niobrara Shale. 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 2010 Operational Highlights

- Oil and natural gas revenues increased 50% to $33.3 million for the three months ended September 30, 2010 from $22.2 million for the three months ended September 30, 2009.

- Net income increased 90% to $12.7 million for the three months ended September 30, 2010 from $6.7 million for the three months ended September 30, 2009.

- Production increased 27% to approximately 527,000 barrels of oil equivalent, or BOE, for the three months ended September 30, 2010 from approximately 416,000 BOE for the three months ended September 30, 2009.

- During the three months ended September 30, 2010, we drilled 13 gross wells and recompleted 22 gross wells.

2010 Production and Drilling Activity

During the three months ended September 30, 2010, our total net production was 468,000 barrels of oil, 243,000 thousand cubic feet of gas, or Mcf, and 768,000 gallons of liquids, for a total of 527,000 BOE as compared to 373,000 barrels of oil, 161,000 Mcf of gas, and 651,000 gallons of liquids, or 416,000 BOE, for the three months ended September 30, 2009. Our total net production averaged approximately 5,728 BOE per day during the three months ended September 30, 2010 as compared to 4,519 BOE per day during the same period in 2009. The 27% increase in production is primarily related to the 2010 drilling and recompletion activities in our fields partially reduced by the sale of a majority of our production in the Bakken in the second and third quarters of 2009.

WCBB. From January 1, 2010 through October 31, 2010, we recompleted 59 existing wells and drilled 21 wells, of which 19 were completed as producers, one was waiting on completion and one was being drilled. We currently intend to recomplete a total of approximately 65 existing wells and drill a total of 24 wells during 2010.

Aggregate net production from the WCBB field during the three months ended September 30, 2010 was 324,587 BOE, or 3,528 BOE per day, 93% of which was from oil. During October 2010, our average daily net production at WCBB was approximately 3,132

BOE, 98% of which was from oil and 2% of which was from natural gas. The decrease in October 2010 production was the result of minor mechanical issues and normal production declines.

East Hackberry Field. From January 1, 2010 through October 31, 2010, we recompleted eight existing wells and drilled seven wells, of which five were completed as producers, one was waiting on completion and one was being drilled. During 2009, we entered into a two year exploration agreement with an active gulf coast operator covering approximately 2,868 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, 2010 was approximately 123,771 BOE, or 1,345 BOE per day, 96% of which was from oil and 4% of which was from natural gas. During October 2010, our average daily net production at East Hackberry was approximately 1,238 BOE, 99% of which was from oil and 1% of which was from natural gas. The decrease in October 2010 production was the result of minor mechanical issues and normal production declines.

West Hackberry Field. Aggregate net production from the West Hackberry field during the three months ended September 30, 2010 was approximately 3,673 BOE, or 40 BOE per day. During October 2010, our average daily net production at West Hackberry was approximately 32 BOE, 100% of which was from oil.

Permian Basin. On December 20, 2007, we completed the acquisition of approximately 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. Subsequently, we have acquired approximately 9,800 additional net acres, bringing our total acreage position to 13,900 net acres.

Nineteen gross (nine net) wells have been drilled on this acreage in 2010, with 11 completed as producers, six waiting on completion and two wells were drilling. We currently anticipate that three to five additional gross (1.5 to 2.5 net) wells will be drilled on this acreage during 2010.

Aggregate net production from the Permian field during the three months ended September 30, 2010 was approximately 64,807 BOE, or 704 BOE per day. During October 2010, average daily net production at Permian was approximately 790 BOE, of which approximately 59% was oil, 25% was natural gas liquids and 16% was natural gas. The increase in October 2010 production was due to the completion of three wells and three recompletions during October 2010.

Niobrara Shale. We completed the acquisition of 24,468 net acres in the Niobrara Shale in Western Colorado on June 15, 2010. We are in the process of planning a 60 square mile 3-D seismic survey which we are currently permitting and expect to begin shooting in early 2011.

Aggregate net production from the Niobrara play during the three months ended September 30, 2010 was approximately 3,850 BOE, or 42 BOE per day. During October 2010, average daily net production in Niobrara was approximately 46 BOE.

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 October 31, 2010, we held approximately 900 net acres, interests in five wells and an overriding royalty interest in wells drilled prior to our sale, wells drilled subsequent to our sale and wells that might be drilled in the future.

Aggregate net production from the Bakken play during the three months ended September 30, 2010 was approximately 6,095 BOE, or 66 BOE per day. During October 2010, average daily net production in Bakken was approximately 61 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 $25.1 million at September 30, 2010. In addition, we had loaned Grizzly $19,370,000 including interest and net of foreign currency adjustments, as of September 30, 2010. During the 2006/2007, 2007/2008, 2008/2009 and 2009/2010 winter delineation drilling seasons, Grizzly drilled an aggregate of 131 core holes and three water supply test wells, tested five separate lease blocks and conducted a seismic program. Grizzly has finalized plans for its 2010-2011 winter drilling program identifying a total of 89 primary core hole locations and 35 contingent core hole locations. Of the 89 primary core hole locations, Grizzly expects to drill 35 locations at Thickwood Hills, 25 locations at Firebag River, 20 locations at Algar Lake, 5 locations at Athabasca Rapids and 4 locations at Horse River. In addition, current plans provide Grizzly an option of drilling 10 to 15 of the 35 total permitted contingent core hole locations. In March 2010, Grizzly filed an application for the development of an

11,300 barrel per day oil sand project at Algar Lake. Grizzly expects regulatory approval within 12 to 18 months of application submission, followed by an anticipated construction period of 18 months leading to first production. Grizzly recently received the Supplemental Information Request, or SIR, pertaining to its Algar Lake Project application from the Alberta regulatory agencies. This is the standard process by which the Alberta regulatory agencies request additional information on all oil sands project applications. The SIR was received in a timeframe consistent with anticipated timeline for project approval. The engineering and procurement contract for Grizzly s proposed steam assisted gravity drainage facility at Algar Lake has been awarded to SNC-Lavin. Work on the detailed engineering design is underway out of Grizzly s Calgary office and the detailed design of the project is expected to be complete by April 2011.

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. As of September 30, 2010, our net investment in Tatex was $1.9 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 the third quarter of 2010 was approximately 81 MMcf and 400 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, 2008, net to our interest, are 2.739 BCF of gas. Since 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. In December 2009, we purchased an additional approximately 12.9% ownership interest at a cost of approximately $3.4 million bringing our total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Affiliates of Wexford own approximately 34% of our outstanding common stock. Tatex III owns a concession covering one million acres. Tatex III recently completed a 3-D seismic survey on this concession. On September 25, 2010, the first well was spud on our concession. During the nine months ended September 30, 2010, we paid $224,000 in cash calls bringing our total investment in Tatex III to $4.6 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 $28.0 million at September 30, 2010 and $17.5 million at December 31, 2009. 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 write-down 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.

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, 2009 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 September 30, 2010, a valuation allowance of $73.2 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.

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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.

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 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, 2010 and 2009

We reported net income of $12,678,000 for the three months ended September 30, 2010, as compared to $6,674,000 for the three months ended September 30, 2009. This 90% increase in period-to-period net income was due primarily to a 27% increase in net production to 527,000 BOE and an 18% increase in realized BOE prices to $63.14 from $53.34, partially offset by an 18% increase in lease operating expenses, an 11% increase in general and administrative expenses and a 41% increase in production taxes.

Oil and Gas Revenues. For the three months ended September 30, 2010, we reported oil and natural gas revenues of $33,273,000 as compared to oil and natural gas revenues of $22,173,000 during the same period in 2009. This $11,100,000, or 50%, increase in revenues is primarily attributable to a 27% increase in net production to 527,000 BOE from 416,000 BOE and an 18% increase in realized BOE prices to $63.14 from $53.34 for the quarter ended September 30, 2010 as compared to the quarter ended September 30, 2009.

The following table summarizes our oil and natural gas production and related pricing for the three months ended September 30, 2010, as compared to such data for the three months ended September 30, 2009:

	Three Months Ended September 30,	
	2010	**2009**
Oil production volumes (MBbls)	468	373
Gas production volumes (MMcf)	243	161
Liquid production volumes (MGal)	768	651
Oil equivalents (Mboe)	527	416
Average oil price (per Bbl)	$ 67.39	$ 56.62
Average gas price (per Mcf)	$ 4.37	$ 3.09
Average liquids price (per gallon)	$ 0.85	$ 0.82
Oil equivalents (per Boe)	$ 63.14	$ 53.34

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $4,063,000 for the three months ended September 30, 2010 from $3,442,000 for the same period in 2009. This increase is mainly the result of an increase in expenses related to contract labor, equipment repairs and wireline services. 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.

Production Taxes. Production taxes increased to $3,657,000 for the three months ended September 30, 2010 from $2,586,000 for the same period in 2009. This increase was primarily related to a 50% increase in oil and gas revenues and an 18% increase in the average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $10,299,000 for the three months ended September 30, 2010, and consisted of $10,221,000 in depletion on oil and natural gas properties and $78,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $7,387,000 for the three months ended September 30, 2009. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $1,538,000 for the three months ended September 30, 2010 from $1,380,000 for the same period in 2009. This $158,000 increase was due to a slight increase in salaries partially offset by decreases in legal expenses and administrative service reimbursements, partially offset by an increase in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $156,000 for the three months ended September 30, 2010 from $146,000 for the same period in 2009.

Interest Expense. Interest expense increased to $823,000 for the three months ended September 30, 2010 from $614,000 for the same period in 2009 due to an increase in the interest rate paid as well as the recognition of approximately $225,000 in unamortized loan fees associated with the termination of the Bank of America revolving credit facility. Effective September 30, 2010, this facility, along with the term loan with Bank of America, were repaid with borrowings under our new senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, entered into on September 30, 2010. This increase in interest expense was partially offset by a decrease in average debt outstanding for the three moths ended September 30, 2010, as compared to the same period in 2009. Total debt outstanding under our new revolving credit facility was $45.7 million as of September 30, 2010, as compared to $53.1 million outstanding under our prior facilities with Bank of America as of the same date in 2009. Total weighted debt outstanding under our facilities were $44.9 million for the three months ended September 30, 2010 and $61.5 million for the same period in 2009. Until September 30 2010, amounts borrowed under our term loan and revolving credit facility with Bank of America bore interest of 3.76% and 3.25%, respectively. As of September 30, 2010, amounts borrowed under our new revolving credit facility bore interest of 5.75%. Effective October 5, 2010, we elected the Eurodollar rate of 3.76%.

Income Taxes. As of September 30, 2010, we had a net operating loss carry forward of approximately $53.0 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, 2010, a valuation allowance of $73.2 million had been provided for deferred tax assets, with the exception of $554,000 related to alternative minimum taxes. We paid no taxes for the three months ended September 30, 2010.

Comparison of the Nine Months Ended September 30, 2010 and 2009

We reported net income of $33,048,000 for the nine months ended September 30, 2010, as compared to $14,485,000 for the nine months ended September 30, 2009. This 128% increase in period-to-period net income was due primarily to a 26% increase in realized BOE prices to $62.31 from $49.32, a 17% increase in net production to 1,439,000 BOE and a 2% decrease in lease operating expenses, partially offset by a 21% increase in general and administrative expenses and a 52% increase in production taxes.

Oil and Gas Revenues. For the nine months ended September 30, 2010, we reported oil and natural gas revenues of $89,661,000 as compared to oil and natural gas revenues of $60,692,000 during the same period in 2009. This $28,969,000, or 48%, increase in revenues is primarily attributable to a 26% increase in realized BOE prices to $62.31 from $49.32 and a 17% increase in net production to 1,439,000 BOE for the nine months ended September 30, 2010 from 1,231,000 BOE for the nine months ended September 30, 2009.

The following table summarizes our oil and natural gas production and related pricing for the nine months ended September 30, 2010, as compared to such data for the nine months ended September 30, 2009:

	Nine Months Ended September 30,	
	2010	**2009**

Oil production volumes (MBbls)	1,286	1,128
Gas production volumes (MMcf)	624	321
Liquid production volumes (MGal)	2,053	2,075
Oil equivalents (Mboe)	1,439	1,231
Average oil price (per Bbl)	$ 65.98	$ 51.56
Average gas price (per Mcf)	$ 4.51	$ 3.47
Average liquids price (per gallon)	$ 0.97	$ 0.69
Oil equivalents (per Boe)	$ 62.31	$ 49.32

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $12,212,000 for the nine months ended September 30, 2010 from $12,511,000 for the same period in 2009. This decrease is mainly a result of a decrease in expenses related to equipment repairs, gas purchased, well workovers, salt water hauling and the rental of crew boats.

Production Taxes. Production taxes increased to $10,390,000 for the nine months ended September 30, 2010 from $6,856,000 for the same period in 2009. This increase was primarily related to a 48% increase in oil and gas revenues and a 26% increase in the average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $26,912,000 for the nine months ended September 30, 2010, and consisted of $26,684,000 in depletion on oil and natural gas properties and $228,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $22,157,000 for the nine months ended September 30, 2009. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $4,438,000 for the nine months ended September 30, 2010 from $3,659,000 for the same period in 2009. This $779,000 increase was primarily due to an increase in franchise taxes, increases in expenses related to salaries, benefits expenses, and a decrease in administrative service reimbursements, partially offset by an increase in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $461,000 for the nine months ended September 30, 2010 from $432,000 for the same period in 2009.

Interest Expense. Interest expense increased to $2,154,000 for the nine months ended September 30, 2010 from $1,686,000 for the same period in 2009. This increase was due to an increase in the interest rate paid as well as the recognition of approximately $225,000 in unamortized loan fees associated with the termination of the Bank of America revolving credit facility. Effective September 30, 2010, this facility, along with the term loan with Bank of America, were repaid with borrowings under our new senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, entered into on September 30, 2010. This increase in interest expense was partially offset by a decrease in average debt outstanding for the nine moths ended September 30, 2010, as compared to the same period in 2009. Total debt outstanding under our new revolving credit facility was $45.7 million as of September 30, 2010, as compared to $53.1 million outstanding under our prior facility with Bank of America as of the same date in 2009. Total weighted debt outstanding under our facilities were $47.0 million for the nine months ended September 30, 2010 and $62.6 million for the same period in 2009. Until September 30 2010, amounts borrowed under our term loan and revolving credit facility with Bank of America bore interest of 3.76% and 3.25%, respectively. As of September 30, 2010, amounts borrowed under our new revolving credit facility bore interest of 5.75%. Effective October 5, 2010, we elected the Eurodollar rate of 3.76%.

Income Taxes. As of September 30, 2010, we had a net operating loss carry forward of approximately $53.0 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, 2010, a valuation allowance of $73.2 million had been provided for deferred tax assets, with the exception of $554,000 related to alternative minimum taxes. We paid $40,000 of state income tax for the nine months ended September 30, 2010.

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. During 2009, we received proceeds from the sale of Bakken assets, and in 2010 we received net proceeds (before offering expenses) of approximately $21.6 million from the sale of our common stock. 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 natural gas production.

Net cash flow provided by operating activities was $58,234,000 for the nine months ended September 30, 2010 as compared to net cash flow provided by operating activities of $35,812,000 for the same period in 2009. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 26% increase in net realized prices and a 17% increase in our net BOE production.

Net cash used in investing activities for the nine months ended September 30, 2010 was $75,198,000 as compared to $19,906,000 for the same period in 2009. During the nine months ended September 30, 2010, we spent $72,260,000 in additions to oil and natural gas properties, of which $26,691,000 was spent on our 2010 drilling and recompletion programs, $15,480,000 was spent on acquisitions in our Niobrara and Permian fields, $11,638,000 was spent on expenses attributable to the wells drilled during 2009, $3,046,000 was spent on our 2009 recompletions, $5,865,000 was spent on compressors and other facility enhancements, $1,306,000 was spent on plugging costs, $1,648,000 was spent on lease related costs and $2,747,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $2,957,000 was loaned to Grizzly during the nine months ended September 30, 2010. During the nine months ended September 30, 2010, we used cash from operations and proceeds from our equity offering to fund our investing activities.

Net cash provided by financing activities for the nine months ended September 30, 2010 was $17,313,000 as compared to net cash used by financing activities of $15,074,000 for the same period in 2009. The 2010 amount provided by financing activities is primarily attributable to the net proceeds of $21,363,000 from our equity offering and borrowings of $45,700,000 under our new credit facility, partially offset by principal payments of $49,903,000 on borrowings under our prior credit facilities with Bank of

America. The 2009 amount used by financing activities is primarily attributable to principal payments on borrowings of $14,500,000 under our credit facility with Bank of America, partially offset by $29,000 received from the exercise of stock options.

Credit Facility. On March 11, 2005, we entered into a three-year secured credit agreement with Bank of America, N.A. providing for a revolving credit facility. The credit agreement was subsequently amended and restated and, among other things, in December 2009, the maturity date was extended to April 1, 2011. Borrowings under the revolving credit facility were subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. Effective July 19, 2007, the credit facility was increased to $150.0 million and effective December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million.

On August 31, 2009, the lender completed its periodic redetermination of our borrowing base giving consideration to year-end 2008 and mid-year 2009 reserve information and then 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. Our outstanding principal balance at the effective time of this 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 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. We paid the outstanding balance of the term loan in full in February 2010.

Outstanding borrowings under the term loan accrued interest at the Eurodollar rate (as defined in the credit agreement) plus 4.0% or, at our option, at the base rate (which was the highest of the lender s prime rate, the Federal funds rate plus half of 1%, and the one-month Eurodollar rate plus 1%) plus 3%. Effective August 31, 2009, we also agreed to an adjustment in the commitment fees, interest rates for revolving loans and fees for letters of credit under the 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 and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

Our obligations under the credit facility were collateralized by a lien on substantially all of our Louisiana and West Texas assets and were guaranteed by our subsidiaries. The restated credit agreement contained 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 could not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period could not be less than 3.00 to 1.00.

On July 10, 2006, we entered into a $5 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. We made quarterly principal payments of approximately $176,000. Amounts borrowed bore interest at Bank of America Prime. We made quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement were collateralized by a lien on the compressor units. On September 30, 2010, we paid this loan in full with borrowings under the new revolving credit agreement discussed below.

On September 30, 2010, we entered into a $100 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association. The new revolving credit facility matures on September 30, 2013 and has an initial borrowing base availability of $50.0 million. As of September 30, 2010, we had an outstanding balance of $45.7 million drawn under the credit agreement, which is included in long-term debt, net of current maturities, on the accompanying consolidated balance sheet. The amounts borrowed under the credit agreement were used to repay our outstanding indebtedness under our prior revolving credit facility ($42.0 million) and term loan ($2.5 million), each with Bank of America, N.A., as administrative agent, and to terminate such facilities. The new credit agreement is secured by substantially all of our assets. Our wholly-owned subsidiaries guaranteed our obligations under the credit agreement.

Advances under the credit agreement may be in the form of either base rate loans or Eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.75% to 3.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At September 30, 2010, amounts borrowed under the credit agreement bear interest at the base rate (5.75%).

The credit agreement contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) 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. We were in compliance with all covenants at September 30, 2010.

In conjunction with the repayment of the Bank of America revolving credit facility on September 30, 2010, we recognized approximately $225,000 in unamortized loan fees associated with this facility, which is included in interest expense in our accompanying consolidated statements of operations.

As of September 30, 2010, approximately $45.7 million was outstanding under the new revolving credit agreement, which is included in long-term debt, net of current maturities on our accompanying consolidated balance sheets. We have used the proceeds of our borrowings under the credit facilities for the development of our oil and natural gas properties and other capital expenditures, acquisition opportunities and for other general corporate purposes.

Building Loans. In June 2004, we purchased the office building we occupy 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. As of September 30, 2009, approximately $2.4 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, to fund Grizzly s delineation drilling program and for acquisitions, primarily in the Permian Basin. 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 and shot 3-D seismic for the first time in our Hackberry field. The new and reprocessed data enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the fields, 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 were 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. In June 2009, we restarted our drilling programs. We commenced our 2010 drilling programs during March 2010.

Of our net reserves at December 31, 2009, 65.4% 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 booked inventory of prospects includes approximately 21 drilling locations at WCBB. The drilling schedule used in our December 31, 2009 reserve report anticipates that all of those wells will be drilled by 2012. From January 1, 2010 through October 31, 2010, we recompleted 59 wells and drilled 21 wells, with 19 completed as producers, one waiting on completion and one well was drilling. We currently intend to recomplete an additional six wells and drill an additional three new wells during 2010. Our aggregate drilling and recompletion expenditures are currently estimated to be approximately $39.0 million to $42.0 million to drill 24 wells and recomplete approximately 65 existing wells in our WCBB field during 2010.

In our East Hackberry field, from January 1, 2010 through October 31, 2010, we recompleted eight existing wells and drilled seven wells, of which five were completed as producers, one well was waiting on completion and one well was drilling. We currently intend to drill one additional well during 2010. Total capital expenditures for our East Hackberry field during 2010 are estimated at $15.0 to $16.0 million.

In the Permian Basin, our booked inventory of prospects includes 183 gross (89 net) future development drilling locations. Nineteen gross (nine net) wells have been drilled on this acreage in 2010, of which 11 were completed as producers, six were waiting on completion and two wells were drilling. We currently anticipate drilling three to five additional gross (1.5 to 2.5 net) wells during 2010. We currently anticipate that our capital requirements to drill a total of 22 to 24 gross (10 to 11 net) wells and recomplete five gross (2.5 net) wells in the Permian Basin in West Texas will be approximately $15.0 to $17.0.

In the Niobrara Shale in Western Colorado, we are in the process of planning a 60 square mile 3-D seismic survey which we are currently permitting and expect to begin shooting in early 2011. We currently anticipate that our total capital expenditures in the Niobrara Shale will be approximately $1.0 million in 2010.

During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. As of September 30, 2010, our net investment in Grizzly was approximately $25.1 million. In addition, we have loaned Grizzly $19,370,000 including interest and net of foreign currency adjustments as of September 30, 2010. Our capital requirements in 2010 for this project are estimated to be approximately $5.0 million, primarily for the expenses associated with the initial preparations of the Algar Lake facility and planned drilling activity during the 2010-2011 winter drilling season.

Capital expenditures in 2010 relating to our interest in Thailand are expected to be approximately $0.8 million, which we believe will be mostly funded from our share of production from the Phu Horm field.

Our total capital expenditures for 2010 are currently estimated to be in the range of $76.0 to $81.0 million. This is up significantly from the $45.0 million spent in 2009 due to improved commodity pricing and cost environment. In response to the challenging economic conditions existing at the time, we reduced our 2009 drilling and other capital activities until such time that AFE costs could be reduced. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs 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, Niobrara 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. 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

In 2009, 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 and differentials, 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 and differentials, 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. For the period January 2010 through February 2010, 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 $54.81 per barrel, before transportation costs and differentials. 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 and differentials. In November 2010, we entered into forward sales contracts for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials. Under the 2010 contracts, we have committed to deliver approximately 45% of our estimated 2010 production. Under the 2011 contacts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. 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, 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. Beginning in 2009, the Company can access the trust for use in plugging and abandonment charges associated with the property. As of September 30, 2010, the plugging and abandonment trust totaled approximately $3,128,000. At September 30, 2010, the Company has plugged 311 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

New Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, *Improving Disclosures about Fair Value Measurements,* which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosure,* (FASB ASC 820). FASB ASC 820 requires additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) significant transfers between Levels 1, 2 and 3. The updated guidance is effective for annual and interim periods beginning after December 15, 2009. We adopted FASB ASC 820 effective January 1, 2010. The adoption did not have a material impact on our 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, 2010, the West Texas Intermediate posted price for crude oil was $79.75 per bbl and the Henry Hub spot market price of natural gas was $3.87 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.

In 2009, 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 and differentials, 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 and differentials, 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. For the period January 2010 through February 2010, 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 $54.81 per barrel, before transportation costs and differentials. 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 and differentials. In November 2010, we entered into forward sales contracts for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials. Under the 2010 contracts, we have committed to deliver approximately 45% of our estimated 2010 production. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. 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 new revolving credit facility is 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 new revolving credit facility bear interest at the prime rate plus 2.50% (5.75% at September 30, 2010). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $457,000 per year, based on $45.7 million outstanding under our credit facility as of September 30, 2010. As of September 30, 2010, 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, 2010, 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, 2010, 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.

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, Great White Pressure Control LLC, or Great White, and six former Cudd employees 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 alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. 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 remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On

February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that we conspired with the other defendants to misappropriate, and misappropriated, Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, our motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages.

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.

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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, 2009.

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, 2010, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES
Not applicable.

ITEM 4. REMOVED AND RESERVED

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 (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).

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	Credit Agreement, dated as of September 30, 2010, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
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.

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Exhibit Number	Description
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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 5, 2010

GULFPORT ENERGY CORPORATION

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

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

Exhibit Index

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