GULFPORT ENERGY CORP
Form 10-Q
November 13, 2007
Table of Contents

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, 2007

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	**(IRS Employer**
Incorporation or Organization)	**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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check One):

Large Accelerated Filer ¨ Accelerated Filer ¨ Non-Accelerated Filer x

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 October 31, 2007, 37,947,755 shares of common stock were outstanding.

Table of Contents

GULFPORT ENERGY CORPORATION

TABLE OF CONTENTS

		Page
PART I FINANCIAL INFORMATION		
Item 1.	Consolidated Financial Statements:	
	Consolidated Balance Sheets at September 30, 2007 (unaudited) and December 31, 2006	1
	Consolidated Statements of Operations for the Three and Nine Months Ended September 30, 2007 and 2006 (unaudited)	2
	Consolidated Statements of Stockholders Equity and Comprehensive Income for the Nine Months Ended September 30, 2007 and 2006 (unaudited)	3
	Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2007 and 2006 (unaudited)	4
	Notes to Consolidated Financial Statements (unaudited)	5
Item 2.	Management s Discussion and Analysis of Financial Conditions and Results of Operations	15
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	25
Item 4.	Controls and Procedures	26
PART II OTHER INFORMATION		26
Item 1.	Legal Proceedings	26
Item 1.A.	Risk Factors	27
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	27
Item 3.	Defaults Upon Senior Securities	28
Item 4.	Submission of Matters to a Vote of Security Holders	28
Item 5.	Other Information	28
Item 6.	Exhibits	28
Signatures		S-1

Table of Contents

CONSOLIDATED BALANCE SHEETS

	(Unaudited) September 30, 2007	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 1,772,000	$ 6,627,000
Accounts receivable oil and gas	9,173,000	7,585,000
Insurance settlement receivables		541,000
Accounts receivable related parties	3,822,000	4,202,000
Prepaid expenses and other current assets	1,765,000	972,000
Total current assets	16,532,000	19,927,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $1,570,000 and $1,459,000 excluded from amortization in 2007 and 2006, respectively	364,705,000	250,838,000
Other property and equipment	7,036,000	6,651,000
Accumulated depletion, depreciation and amortization	(119,943,000)	(99,815,000)
Property and equipment, net	251,798,000	157,674,000
Other assets	32,207,000	17,550,000
Total assets	$ 300,537,000	$ 195,151,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 34,582,000	$ 24,793,000
Asset retirement obligation current	480,000	480,000
Current maturities of long-term debt	807,000	835,000
Total current liabilities	35,869,000	26,108,000
Asset retirement obligation long-term	8,213,000	8,378,000
Long-term debt, net of current maturities	36,425,000	36,856,000
Total liabilities	80,507,000	71,342,000
Commitments and contingencies (Note 12)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding		
Stockholders equity:		
Common stock $.01 par value, 55,000,000 authorized, 37,944,603 issued and outstanding in 2007 and 33,659,759 in 2006	379,000	337,000
Paid-in capital	196,137,000	131,610,000
Accumulated other comprehensive income	2,094,000	
Retained earnings (accumulated deficit)	21,420,000	(8,138,000)
Total stockholders equity	220,030,000	123,809,000

Total liabilities and stockholders equity	$ 300,537,000	$ 195,151,000

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Revenues:				
Gas sales	$ 1,500,000	$ 2,371,000	$ 3,993,000	$ 3,418,000
Oil and condensate sales	28,472,000	21,653,000	71,360,000	39,404,000
Other income (expense)	3,000	(36,000)	12,000	(19,000)
	29,975,000	23,988,000	75,365,000	42,803,000
Costs and expenses:				
Lease operating expenses	4,008,000	2,954,000	11,127,000	6,559,000
Production taxes	3,547,000	2,936,000	9,017,000	5,422,000
Depreciation, depletion, and amortization	7,845,000	4,488,000	20,128,000	8,224,000
General and administrative	1,192,000	717,000	3,427,000	2,232,000
Accretion expense	138,000	149,000	415,000	447,000
	16,730,000	11,244,000	44,114,000	22,884,000
INCOME FROM OPERATIONS:	13,245,000	12,744,000	31,251,000	19,919,000
OTHER (INCOME) EXPENSE:				
Interest expense	654,000	644,000	1,979,000	1,312,000
Business interruption insurance recoveries		(332,000)		(3,601,000)
Interest income	(114,000)	(85,000)	(343,000)	(196,000)
	540,000	227,000	1,636,000	(2,485,000)
INCOME BEFORE INCOME TAXES	12,705,000	12,517,000	29,615,000	22,404,000
INCOME TAX EXPENSE:	4,000		57,000	
NET INCOME	$ 12,701,000	$ 12,517,000	$ 29,558,000	$ 22,404,000
NET INCOME PER COMMON SHARE:				
Basic	$ 0.34	$ 0.38	$ 0.82	$ 0.69
Diluted	$ 0.33	$ 0.37	$ 0.80	$ 0.66

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION

Consolidated Statements of Stockholders Equity and Comprehensive Income

(Unaudited)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)	Total Stockholders Equity
Balance at January 1, 2007	33,659,759	$ 337,000	$ 131,610,000	$	$ (8,138,000)	$ 123,809,000
Net income					29,558,000	29,558,000
Other Comprehensive Income:						
Foreign currency translation adjustment				2,094,000		2,094,000
Total Comprehensive Income						31,652,000
Stock Compensation			875,000			875,000
Issuance of Common Stock in public offerings, net of related expenses of $572,000	4,047,500	40,000	62,786,000			62,826,000
Issuance of Restricted Stock	26,946					
Issuance of Common Stock through exercise of options	210,398	2,000	866,000			868,000
Balance at September 30, 2007	37,944,603	$ 379,000	$ 196,137,000	$ 2,094,000	$ 21,420,000	$ 220,030,000
Balance at January 1, 2006	32,168,203	$ 322,000	$ 119,192,000	$ 759,000	$ (35,946,000)	$ 84,327,000
Net income					22,404,000	22,404,000
Other Comprehensive Income:						
Unrealized gain on hedges				78,000		78,000
Deferred gain on settled contracts				(114,000)		(114,000)
Loss on hedging ineffectiveness				159,000		159,000
Reclassification adjustment on settled hedges				(603,000)		(603,000)
Total Comprehensive Income						21,924,000
Stock Compensation			763,000			763,000
Issuance of Common Stock in public offering, net of related expenses of $479,000	790,000	8,000	9,964,000			9,972,000
Issuance of Restricted Stock	14,842					
Issuance of Common Stock through exercise of warrants	113,852	1,000	120,000			121,000
Issuance of Common Stock through exercise of options	14,332		45,000			45,000
Balance at September 30, 2006	33,101,229	$ 331,000	$ 130,084,000	$ 279,000	$ (13,542,000)	$ 117,152,000

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2007	2006
Cash flows from operating activities:		
Net income	$ 29,558,000	$ 22,404,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount Asset Retirement Obligation	415,000	447,000
Depletion, depreciation and amortization	20,128,000	8,224,000
Stock-based compensation expense	639,000	568,000
Loss from equity investments	109,000	39,000
Unrealized loss on hedge ineffectiveness		159,000
Changes in operating assets and liabilities:		
Increase in accounts receivable	(1,588,000)	(6,577,000)
Decrease in business interruption insurance settlement receivable		1,710,000
Decrease (increase) in accounts receivable related party	380,000	(476,000)
Increase in prepaid expenses	(793,000)	(304,000)
Increase in deposits		(3,000)
Decrease (increase) in accounts payable and accrued liabilities	(740,000)	2,527,000
Decrease in deferred hedge gains		(114,000)
Settlements of asset retirement obligation	(872,000)	(670,000)
Net cash provided by operating activities	47,236,000	27,934,000
Cash flows from investing activities:		
Additions to cash held in escrow	(95,000)	(73,000)
Additions to other property, plant and equipment	(385,000)	(472,000)
Additions to oil and gas properties	(102,757,000)	(42,387,000)
Proceeds from sale of oil and gas properties	500,000	
Investment in Grizzly Oil Sands ULC	(12,374,000)	(8,199,000)
Investment in Tatex Thailand II, LLC	(88,000)	(678,000)
Investment in Windsor Bakken, LLC	(127,000)	(1,346,000)
Net cash used in investing activities	(115,326,000)	(53,155,000)
Cash flows from financing activities:		
Principal payments on borrowings	(46,959,000)	(10,780,000)
Borrowings on note payable	46,500,000	29,841,000
Proceeds from issuance of common stock, net of offering costs of $572,000 and $479,000, and exercise of stock options	63,694,000	10,138,000
Net cash provided by financing activities	63,235,000	29,199,000
Net increase (decrease) in cash and cash equivalents	(4,855,000)	3,978,000
Cash and cash equivalents at beginning of period	6,627,000	2,119,000
Cash and cash equivalents at end of period	$ 1,772,000	$ 6,097,000

Supplemental disclosure of cash flow information:				
Interest payments	$	2,378,000	$	1,312,000
Supplemental disclosure of non-cash transactions:				
Capitalized stock based compensation	$	236,000	$	195,000
Asset retirement obligation capitalized	$	292,000	$	290,000

See accompanying notes to consolidated financial statements.

Table of Contents

GULPORT 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-KSB. Results for the three month and nine month periods ended September 30, 2007 are not necessarily indicative of the results expected for the full year.

1. INSURANCE SETTLEMENT RECEIVABLE

The Company sustained damage to both its Hackberry field located in Cameron Parish, Louisiana and its West Cote Blanche Bay (WCBB) field located in St. Mary Parish, Louisiana as a result of Hurricane Rita in September 2005. As of September 30, 2007, the Company had incurred costs of $14,388,000 relating to the damage to the fields and facilities. Of this amount, $250,000 represents insurance deductible amounts that were expensed to lease operating expenses in 2005. The Company received $8,396,000 in insurance proceeds related to physical damage, of which $541,000 was received in the first quarter of 2007, which are reflected as investing activity in the consolidated statements of cash flows. Approximately $5,634,000 of costs incurred during 2006 and the first quarter of 2007 related to equipment and facilities replacement costs which will not be reimbursed by insurance and are included in the full cost pool. Approximately $108,000 previously included in insurance settlement receivables was not collected and was expensed in 2006. At September 30, 2007, the Company had collected all outstanding insurance receivable amounts related to physical damage.

The Company maintained business interruption insurance to cover lost production revenue in the event of shut-in production. The business interruption insurance began 60 days after the occurrence of the insurable event, subject to a daily limit of $45,000 and had a maximum coverage of 180 days. Coverage began on November 24, 2005 for shut-in production caused by Hurricane Rita. For the three months and nine months ended September 30, 2006, the Company recognized $332,000 and $3,601,000, respectively, of business interruption insurance proceeds in other income in the consolidated statements of operations. As of September 30, 2006, the Company had received proceeds of $5,311,000 ($1,710,000 of which was accrued in 2005) related to business interruption for the period of November 24, 2005 to May 1, 2006. Such recoveries are presented as operating cash flows in the consolidated statements of cash flows. All business interruption recoveries were collected in 2006.

2. ACCOUNTS RECEIVABLE RELATED PARTY

Included in the accompanying September 30, 2007 and December 31, 2006 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 direct 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, 2007 and December 31, 2006, this receivable amount totaled $3,822,000 and $4,202,000, respectively. The Company was reimbursed $3,047,000 and $9,685,000 for the three months and nine months ended September 30, 2007, respectively, for general and administrative functions which are reflected as a reduction of general and administrative expenses in the consolidated statements of operations and include the amounts under service contracts discussed below. For the three months and nine months ended September 30, 2006, the Company was reimbursed $3,118,000 and $7,680,000, respectively.

Effective September 29, 2006, the Company entered into an administrative services agreement with Diamondback Energy Services LLC (Diamondback). Under the agreement, the Company s services for Diamondback include accounting, human resources, legal and technical support. The services provided to Diamondback and the fees for such

services can be amended by mutual agreement of the parties. The administrative services agreement has a three-year term, and upon expiration of that term the agreement will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. The administrative services agreement is terminable (1) by Diamondback at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company was reimbursed approximately $36,000 and $814,000 in consideration for those services during the three months and nine months ended September 30, 2006, respectively, and $5,000 during the three months and nine months ended September 30, 2007. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Effective July 22, 2006, the Company entered into an administrative services agreement with Great White Energy Services LLC (Great White). Under the agreement, the Company s services for Great White include accounting, human resources, legal and technical support. The services provided to Great White and the fees for such services can be amended by mutual agreement of the parties. The administrative services agreement has a three-year term, and upon expiration of that term the agreement will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. The administrative services agreement is terminable (1) by Great White at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company was reimbursed approximately $19,000 and $729,000 in consideration for those services during the three months and nine months ended September 30, 2007, respectively, and $624,000 and $716,000 during the three months and nine months ended September 30, 2006, respectively. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, and amortization as of September 30, 2007 and December 31, 2006 are as follows:

	September 30, 2007	December 31, 2006
Oil and natural gas properties	$ 364,705,000	$ 250,838,000
Office furniture and fixtures	2,850,000	2,465,000
Building	3,926,000	3,926,000
Land	260,000	260,000
Total property and equipment	371,741,000	257,489,000
Accumulated depletion, depreciation, amortization and impairment reserve	(119,943,000)	(99,815,000)
Property and equipment, net	$ 251,798,000	$ 157,674,000

Included in oil and natural gas properties at September 30, 2007 is the cumulative capitalization of $5,131,000 in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $410,000 and $1,203,000 for the three months and nine months ended September 30, 2007, respectively, and $251,000 and $671,000 for the three months and nine months ended September 30, 2006, respectively.

Table of Contents

A reconciliation of the asset retirement obligation for the nine months ended September 30, 2007 and 2006 is as follows:

	September 30, 2007	September 30, 2006
Asset retirement obligation, beginning of period	$ 8,858,000	$ 8,609,000
Liabilities incurred	292,000	290,000
Liabilities settled	(872,000)	(670,000)
Accretion expense	415,000	447,000
Asset retirement obligation as of end of period	8,693,000	8,676,000
Less current portion	480,000	480,000
Asset retirement obligation, long-term	$ 8,213,000	$ 8,196,000

4. OTHER ASSETS

Other assets consist of the following as of September 30, 2007 and December 31, 2006:

	September 30, 2007	December 31, 2006
Plugging and abandonment escrow account on the WCBB properties (Note 12)	$ 3,078,000	$ 2,983,000
Investment in Tatex Thailand II, LLC	3,553,000	3,465,000
Investment in Windsor Bakken, LLC	2,534,000	2,433,000
Investment in Grizzly Oil Sands ULC	22,838,000	8,465,000
Certificates of Deposit securing letter of credit	200,000	200,000
Deposits	4,000	4,000
	$ 32,207,000	$ 17,550,000

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 other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (APICO), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During the nine months ended September 30, 2007, Gulfport paid $88,000 in cash calls, bringing its total investment in Tatex (including previous investments) to $3,553,000. The loss on equity investment related to Tatex was immaterial for the three and nine months ended September 30, 2007 and 2006.

Windsor Bakken, LLC

During 2005, the Company purchased a 20% ownership interest in Windsor Bakken, LLC (Bakken). The remaining interests in Bakken are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. In 2005 and 2006, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. As of September 30, 2007, Gulfport s net investment in Bakken was $2,534,000. As of September 30, 2007, Bakken had commenced drilling of some its undeveloped acreage. The Company recognized a $1,000 gain and $26,000 loss on equity investment for the three months and nine months ended September 30, 2007, respectively, and a loss of $29,000 for the three and nine months ended 2006, which is included in other income (expense) in the consolidated statements of operations.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oils Sands ULC (Grizzly), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by other entities controlled by Wexford Capital LLC, an affiliate of Gulfport. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. Grizzly has commenced drilling of core holes for feasibility of oil production in three separate lease blocks but has not commenced development of operations. As of September 30, 2007, Gulfport s net investment in Grizzly was $22,838,000. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was increased by $3,020,000 and $2,094,000 as a result of a currency translation gain for the three months and nine months ended September 30, 2007, respectively. The Company recognized a loss on equity investment of $47,000 and $83,000 for the three months and nine months ended September 30, 2007, respectively, and a loss of $10,000 for the three and nine months ended September 30, 2006, which is included in other income (expense) in the consolidated statements of operations.

Table of Contents

5. LONG-TERM DEBT

A breakdown of long-term debt as of September 30, 2007 and December 31, 2006 is as follows:

	September 30, 2007	December 31, 2006
Reducing credit agreement (1)	$ 30,020,000	$ 29,848,000
Term loan (1)	4,471,000	5,000,000
Building loans (2)	2,741,000	2,843,000
Less: current maturities of long term debt	(807,000)	(835,000)
Debt reflected as long term	$ 36,425,000	$ 36,856,000

Maturities of long-term debt as of September 30, 2007 are as follows:

2008	$ 807,000
2009	30,834,000
2010	820,000
2011	3,158,000
2012	714,000
Thereafter	899,000
Total	$ 37,232,000

(1) On March 11, 2005, Gulfport entered into a three-year secured reducing credit agreement providing for a $30.0 million revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility was increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. The credit facility has a term of three years and all principal amounts of revolving loans outstanding under the credit facility, together with all accrued and unpaid interest and fees were to be due and payable on March 11, 2008. The maturity date was subsequently amended to March 31, 2009. The Company makes quarterly interest payments on amounts borrowed under the facility. Amounts borrowed under the credit facility bear interest at Bank of America Prime plus 0.25% (8.5% at September 30, 2007). The Company s obligations under the credit facility are collateralized by a lien on substantially all of the Company s Louisiana assets. The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of current assets to current liabilities may not be less than 1.00 to 1.00; (b) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve month period may not be greater than 2.00 to 1.00; and (c) 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 not in compliance with the current ratio covenant at September 30, 2007; however, a waiver has been obtained through October 1, 2008 from the lender. As of September 30, 2007, approximately $30.0 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. The Company has used the proceeds of borrowings under the credit facility for the exploration of oil and natural gas properties and other capital expenditures, acquisition opportunities, repair of damaged facilities and for other general corporate purposes.

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 amortizes quarterly beginning March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. Amounts borrowed bear interest at Bank of America Prime (8.25% at September 30, 2007). The Company makes quarterly interest payments on amounts borrowed under the agreement. The Company s obligations under the agreement are collateralized by a lien on the compressor units. As of September 30, 2007, approximately $4.5 million was outstanding under this agreement, of which $714,000 and $3,757,000 are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on the accompanying consolidated balance sheet.

8

Table of Contents

(2) In June 2004 the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3,700,000. 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. In addition, the building loans included a loan related to a building in Lafayette, Louisiana, purchased in 1996 to be used as the Company s Louisiana headquarters. This loan bore interest at the rate of 5.75% per annum. The Company paid this loan in full during the third quarter of 2007, in advance of its February 2008 maturity date. All building loans require monthly interest and principal payments and are collateralized by the respective land and buildings.

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

Sale of Common Stock

On January 30, 2007, the Company sold 1,150,000 shares of common stock in an underwritten offering at an offering price to the public of $11.92 per share. In connection with the offering, the Company granted the underwriter an option to purchase up to an additional 172,500 shares of common stock to cover any over-allotments, which the underwriter exercised in full on February 1, 2007. The Company received the net proceeds of approximately $15.3 million from the sale of these shares on February 5, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down existing debt under the Company s credit facility.

In May 2007, the Company sold 1,500,000 shares of common stock in an underwritten offering at an offering price to the public of $16.00 per share. In connection with the offering, the Company granted the underwriter an option to purchase up to an additional 225,000 shares of common stock to cover any over-allotments, which the underwriter exercised in full. The Company received the net proceeds of approximately $26.8 million from the sale of these shares on May 22, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down outstanding debt under the Company s credit facility.

In July 2007, the Company sold 1,000,000 shares of common stock in an underwritten offering at an offering price to the public of $22.00 per share. The Company received the net proceeds of approximately $21.2 million from the sale of these shares on July 25, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down outstanding debt under the Company s credit facility.

Restricted Stock

On April 1, 2007, the Company granted 16,389 shares of restricted common stock of the Company. These shares vest monthly over a three year period. On May 15, 2007, the Company granted 10,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period. On August 14, 2007, the Company granted 8,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period.

7. STOCK-BASED COMPENSATION

On January 1, 2006, the Company changed its method of accounting for share-based compensation from the APB No. 25 intrinsic-value accounting method to the fair value recognition provisions of SFAS No. 123(R). During the three months and nine months ended September 30, 2007, the Company s stock-based compensation expense was $294,000 and $875,000, respectively, of which the Company capitalized $79,000 and $236,000, respectively, relating to its exploration and development efforts. During the three months and nine months ended September 30, 2006, the Company s stock-based compensation expense was $395,000 and $763,000, respectively, of which the Company capitalized $107,000 and $195,000, respectively, relating to its exploration and development efforts. Stock based compensation expense reduced basic and diluted earnings per share by $0.01 and $0.02 each for the three months and nine months ended September 30, 2007, respectively and by $0.01 and $0.02 for the three months and nine months ended September 30, 2006, 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.

Table of Contents

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model that uses the assumptions noted in the following table. 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 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 granted during the nine months ended September 30, 2007. The following table provides information relating to stock options granted for the nine months ended September 30, 2006:

	September 30, 2006
Expected volatility	40.9%
Expected life in years	4.0
Weighted average risk free interest rate	4.0%

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, 2007 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2006	967,233	$ 5.54	7.76	$ 7,782,000
Granted				
Exercised	(210,398)	4.13		2,284,000
Forfeited/expired	(52,334)	3.16		
Options outstanding at September 30, 2007	704,501	$ 6.14	7.23	$ 12,308,000
Options exercisable at September 30, 2007	244,361	$ 7.96	6.71	$ 3,837,000

Unrecognized compensation expense as of September 30, 2007 related to outstanding stock options and restricted shares was $1,974,000. The expense is expected to be recognized over a weighted average period of 1.53 years.

The following table summarizes information about the stock options outstanding at September 30, 2007:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$ 2.00	53,250	2.10	53,250
$ 3.36	369,695	7.31	27,333
$ 9.07	81,556	7.94	41,556
$ 11.20	200,000	8.17	122,222
	704,501		244,361

Table of Contents

The following table summarizes restricted stock activity for the nine months ended September 30, 2007:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2006	69,518	$ 12.81
Granted	34,389	15.17
Vested	(26,946)	13.03
Forfeited	(4,861)	15.80
Unvested shares as of September 30, 2007	72,100	$ 13.65

8. EARNINGS PER SHARE

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

	For the three months ended September 30, 2007			2006		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 12,701,000	37,671,681	$ 0.34	$ 12,517,000	33,074,396	$ 0.38
Effect of dilutive securities:						
Stock options and awards		678,533			1,079,950	
Diluted:						
Net income	$ 12,701,000	38,350,214	$ 0.33	$ 12,517,000	34,154,346	$ 0.37

	For the nine months ended September 30, 2007			2006		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 29,558,000	36,048,327	$ 0.82	$ 22,404,000	32,632,458	$ 0.69
Effect of dilutive securities:						
Stock options and awards		673,416			1,179,872	
Diluted:						
Net income	$ 29,558,000	36,721,743	$ 0.80	$ 22,404,000	33,812,330	$ 0.66

Options to purchase 200,000 shares at $11.20 per share were excluded from the calculation of dilutive earnings per share for the three month and nine month periods ended September 30, 2006 because the effect of such options was anti-dilutive. Options to purchase 40,000 shares at $12.17 per share and 120,000 shares at $9.07 were also excluded for the calculation of dilutive earnings for the three month period ended September 30, 2006 because the effect of such options was anti-dilutive. There were no potential shares of common stock that were considered anti-dilutive during the three month or nine month periods ended September 30, 2007.

Table of Contents

9. OTHER COMPREHENSIVE INCOME

Other comprehensive income for the three months and nine months ended September 30, 2007 and 2006 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income	$ 12,701,000	$ 12,517,000	$ 29,558,000	$ 22,404,000
Other comprehensive income (loss):				
Foreign currency translation adjustment	3,020,000		2,094,000	
Unrealized gain on hedges		1,654,000		78,000
Deferred gain on settled contracts		(144,000)		(114,000)
(Gain) loss on hedging ineffectiveness		(4,000)		159,000
Reclassification of settled contracts		1,309,000		(603,000)
Total comprehensive income	$ 15,721,000	$ 15,332,000	$ 31,652,000	$ 21,924,000

10. NEW ACCOUNTING STANDARDS

The Company adopted FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*, as of January 1, 2007. The adoption of this Interpretation had no effect on the Company s consolidated financial statements. The Company is subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. The Company s 2003-2006 U.S. federal and state income tax returns remain open to examination by the Internal Revenue Service. The Company is continuing its practice of recognizing interest and/or penalties related to income tax matters as general and administrative expenses.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption permitted. The Company is currently assessing the impact, if any, of the adoption of SFAS 157.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which the Company elects the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided the Company also elects to apply the provisions of SFAS No. 157, *Fair Value Measurements*, at the same time. The Company is currently assessing the impact, if any, of the adoption of SFAS No. 159.

11. 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 $73,000 as of September 30, 2007. The lease commenced on October 15, 2006 and expires October 14, 2009, with equal monthly installments of $10,500. The future minimum lease payments to be received are as follows:

Fiscal year ending December 31	
2007	$ 31,500
2008	126,000

2009	94,500
	$ 252,000

12

Table of Contents

12. 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, 2007, the plugging and abandonment trust totaled approximately $3,078,000, including interest received during 2007 of approximately $100,000. The Company has plugged 231 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its minimum plugging obligation through March 31, 2007.

Pending Settlements

The Louisiana State Mineral Board (LSMB) is disputing Gulfport s royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The LSMB maintains that Gulfport paid approximately $1,400,000 less in royalties under the fixed price contracts than the royalties Gulfport would have had to pay had it sold the oil at prevailing market rates. Gulfport has denied any liability to the LSMB for underpayment of royalties and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. Gulfport met with the Attorney General on several occasions and recently reached a mutual settlement. The settlement requires Gulfport to pay $250,000, which has been accrued in accounts payable and accrued liabilities in the accompanying consolidated balance sheet and all future royalties will be paid at market price, regardless of the presence of fixed price contracts. Gulfport is currently working with the Attorney General to finalize the agreement.

Other Litigation

In the Company s Quarterly Report on Form 10-Q for the second quarter of 2007, filed with the Securities and Exchange Commission on August 14, 2007, the Company provided information regarding certain pending lawsuits. This included information relating to an accident that occurred in October 2006 north of Gulfport s production facilities in the West Cote Blanche Bay field in Southern Louisiana involving a tug boat owned by 4-K Marine LLC and two barges owned by Athena Construction LLC (Athena) that were performing work on behalf of Gulfport. The accident resulted in a rupture of an underwater natural gas pipeline, subsequent fire damage to the vehicles and six fatalities. Since the filing of the Form 10-Q, a new lawsuit has been filed on October 15, 2007 by Brian Dumesnil in the 16th Judicial District Court for the Parish of St. Mary, Louisiana against Gulfport, Chevron USA, Inc., Chevron Texaco Pipeline Holdings, Inc., Chevron Natural Gas Services, Inc., Diamondback Energy Services LLC, an affiliate of Gulfport, and the estate of Timothy Tauzin, the deceased captain of the tug boat involved in the accident. Mr. Dumesnil was employed by Athena and was on the Athena barge at the time of the accident. He is seeking unspecified sums of money as a result of the alleged negligence of defendants and injuries incurred following the October 2006 accident. The Company is currently working to respond to this matter. No deadlines have been set with respect to this lawsuit. In addition, both the Hummel and Davis suits were stayed by the court on September 6, 2007.

In addition, since the Company s last report on Form 10-Q, Gulfport filed a motion for summary judgment on October 5, 2007 in a lawsuit filed in November 2006 by Cudd Pressure Control, Inc. against Gulfport and Great White Pressure Control LLC, an affiliate of Gulfport. The plaintiff has until November 15, 2007 to respond.

Further, since the Company s last report on Form 10-Q, Gulfport agreed to respond to a putative class action lawsuit, filed in July 2007 by Robotti & Company, LLC, following notification from the plaintiff.

Litigation is inherently uncertain and its outcome cannot be predicted at this time. Adverse decisions in one or more of the above referenced matters could have a material adverse effect on the financial condition or results of operations of the Company.

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

Except as discussed herein, this report does not modify, amend or update in any way the description of any legal proceedings or any other item or disclosures set forth in the Company s Form 10-Q for the second quarter of 2007.

Table of Contents

Forward Sales Contracts

The Company has entered into forward sales contracts for the period of July 2007 through May 2008 for the sale of 3,500 barrels of production per day at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, the Company has entered into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of $71.69 per barrel before transportation costs. For the months of July 2008 and August 2008 and the period September 2008 through December 2008, the Company has entered into forward sales contracts for the sale of 2,000 barrels of production per day in each such period at weighted average daily prices of $77.20, $79.95 and $79.59 per barrel, respectively, in each case before transportation costs. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production.

Table of Contents

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-KSB 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 Annual Report on Form 10-KSB, 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. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and have interests in entities that operate in Southeast Asia, including the Phu Horn gas field in Thailand. In addition, Gulfport is actively participating in 11 wells in the Bakken play in the Williston Basin in North Dakota. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In 2006, at our WCBB field we drilled 27 wells and recompleted 18 existing wells for a total cost to date of $45.3 million. Of our 27 new wells drilled at WCBB in 2006, 24 were completed as producing wells and three were non-productive. During 2007, we intend to drill 26 wells and have recompleted 49 existing wells at our WCBB field for an estimated aggregate cost of $50 million. From January 1, 2007 through November 1, 2007, at WCBB we drilled 22 new wells of which 18 were productive and four were non-productive.

During 2005, we completed a 3-D seismic shoot at our East Hackberry field. In late 2006, we drilled one well in East Hackberry. From January 1, 2007 through November 1, 2007, at East Hackberry we drilled eight wells in Lake Calcasieu and three wells on land. Seven wells are producing, two are waiting to be sidetracked, and two were non-productive. We are currently drilling our twelfth East Hackberry well of 2007.

As of December 31, 2006, we had 23.2 million barrels of oil equivalent, or MBOE, of proved reserves.

Recent Developments

Current Production. During the nine months ended September 30, 2007, our total net production was 1,116,000 barrels of oil and 531,000 thousand cubic feet of gas, or Mcf, or 1,204,000 BOE, compared to 599,000 barrels of oil and 552,000 Mcf of gas, or 691,000 BOE, for the nine months ended September 30, 2006. Our total net production averaged approximately 4,411 BOE per day during the nine months ended September 30, 2007 compared to 2,533 BOE per day during the same period in 2006. Production for the nine months ended September 30, 2006 was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

15

WCBB. From January 1, 2007 through November 1, 2007, we drilled 22 new wells of which 18 were productive and four were non-productive. The 18 productive wells, with total depths ranging from 6,107 to 10,383 feet, have approximately 2,427 feet of aggregate apparent net pay. As of November 1, 2007, we were drilling our 23rd well of 2007 at WCBB.

Aggregate net production from the WCBB field during the nine months ended September 30, 2007 was 1,071,000 BOE, approximately 95% of which was from oil and 5% of which was from natural gas. For October, 2007, average daily net production at WCBB was approximately 4,108 BOE, 95 % of which was from oil and 5% of which was from natural gas.

East Hackberry Field. During 2005, we completed a proprietary 42 square mile 3-D seismic survey at East Hackberry. Given that drilling activities at the East Hackberry field prior to our acquisition of the field in 1997 were undertaken without the benefit of modern seismic information, we believe that the acquired 3-D seismic data has enhanced our probability of drilling success. We continue to evaluate the 3-D seismic data to identify additional drilling locations. From January 1, 2007 through November 1, 2007, we drilled 11 wells and as of November 1, 2007 we were in the process of drilling our 12th East Hackberry well of 2007. Seven of the wells are producing, two are waiting to be sidetracked, and two were non-productive. Drilling activity in this field targets measured depths ranging from approximately 8,000 to 13,000 feet using directional drilling techniques. We have now completed the installation of our new production barge facility and are currently producing five wells into the facility. We recently added an additional 1,100 acres to our East Hackberry leasehold and now hold approximately 4,934 acres in the field. We have also exercised an option to acquire an additional 3,300 acres, which will bring our total East Hackberry acreage to 8,234 upon our receipt of state approval. We anticipate that our total capital expenditures at East Hackberry during 2007 will be approximately $60 million to $70 million.

Aggregate net production from the East Hackberry field during the nine months ended September 30, 2007 was approximately 103,000 BOE, 81% of which was from oil and 19% of which was from natural gas. For October, 2007, average daily net production at East Hackberry was approximately 1,078 BOE, 77% of which was from oil and 23% of which was from natural gas.

West Hackberry Field. There have been 36 wells drilled to date on our portion of West Hackberry. Currently, three are producing, 24 are shut-in and one has been converted to a saltwater disposal well. The remaining eight wells have been plugged and abandoned.

Aggregate net production from the West Hackberry field during the nine months ended September 30, 2007 was approximately 13,000 BOE. For October, 2007, average daily net production at West Hackberry was approximately 58 BOE.

Grizzly Oil Sands ULC. During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oils Sands ULC, or Grizzly, a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by other entities controlled by Wexford Capital LLC, or Wexford, an affiliate of ours. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. As of November 1, 2007, Grizzly had approximately 511,000 acres under lease. Grizzly drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks using up to four different rigs and at this time has not commenced development of operations. As of September 30, 2007, our net investment in Grizzly was $22,838,000. Grizzly s functional currency is the Canadian dollar. Our investment in Grizzly was increased by $3,020,000 and $2,094,000 as a result of a currency translation gain for the three months and nine months ended September 30, 2007, respectively. Future plans currently include continuing to acquire leases, an additional 80 to 120 core hole drilling and seismic program during the 2007/2008 winter drilling season and possible construction of a 10,000 barrel per day steam assisted gravity drainage facility that could lead to initial production in 2011.

Tatex Thailand II, LLC. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex, at a cost of $2,400,000. The remaining interests in Tatex are owned by other entities controlled by Wexford. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During the nine months ended September 30, 2007, we paid $88,000 in cash calls, bringing our total investment in Tatex (including previous investments) to $3,553,000.

Table of Contents

Windsor Bakken, LLC. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken are owned by other entities controlled by Wexford. In 2005 and 2006, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. As of September 30, 2007, our net investment in Bakken was $2,534,000. As of September 30, 2007, Bakken had commenced drilling of some of its undeveloped acreage. We are currently participating in 11 wells. Total capital expenditures are estimated at approximately $1 million.

Insurance Coverage. We sustained damage to both our Hackberry field located in Cameron Parish, Louisiana and our WCBB field located in St. Mary Parish, Louisiana as a result of Hurricane Rita in September 2005. As of September 30, 2007, we had incurred costs of $14,388,000 relating to the damage to the fields and facilities. Of this amount, $250,000 represents insurance deductible amounts that were expensed to lease operating expenses in 2005. We received $8,396,000 in insurance proceeds related to physical damage, of which $541,000 was received in the first quarter of 2007, and is reflected as investing activity in the consolidated statements of cash flows. Approximately $5,634,000 of costs incurred during 2006 and 2007 related to equipment and facilities replacement costs which will not be reimbursed by insurance and is included in the full cost pool. Approximately $108,000 previously included in insurance settlement receivables was not collected and was expensed in fourth quarter 2006. We had collected all outstanding insurance receivable amounts related to physical damage insurance as of the end of the first quarter 2007.

At the time of Hurricane Rita, we also maintained business interruption insurance to cover lost production revenue in the event of shut-in production. The business interruption insurance began 60 days after the occurrence of the insurable event, subject to a daily limit of $45,000 and had a maximum coverage of 180 days. Coverage began on November 24, 2005 for shut-in production caused by Hurricane Rita. For the three months and nine months ended September 30, 2006, we recognized $332,000 and $3,601,000, respectively, of business interruption insurance proceeds in other income in the consolidated statements of operations. As of September 30, 2006, we had received proceeds of $5,311,000 ($1,710,000 of which was accrued in 2005) related to business interruption for the period of November 24, 2005 to May 1, 2006. Such recoveries are presented as operating cash flows in the consolidated statements of cash flows. All business interruption recoveries were collected in 2006.

During May 2007, we placed both our physical damage and business interruption insurance coverage with new carriers. We now have a total of $10,000,000 in coverage which may be used in whole or in part on either physical damage or business interruption or any combination thereof. In addition, we separately insure our new barge production facility in our East Hackberry field.

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. Our significant accounting policies are described in Note 1 to our consolidated financial statements included in our annual report on Form 10-KSB for the fiscal year ended December 31, 2006, filed with the SEC on April 2, 2007. 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 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 $1,570,000 at September 30, 2007 and $1,459,000 at December 31, 2006. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

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

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 Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, SFAS No. 143, 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. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates 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 (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2006, a valuation allowance of $25,509,000 had been provided for deferred tax assets based on the uncertainty of future taxable income.

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

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

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended. 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 SFAS 133, 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. As of June 30, 2007, we had entered into forward sales contracts for the sale of 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of $70.15 per barrel before transportation costs. For the period of July 2007 through May 2008, we have entered into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have entered into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of $71.69 per barrel before transportation costs. For the months of July 2008 and August 2008 and the period September 2008 through December 2008, we have entered into forward sales contracts for the sale of 2,000 barrels of production per day in each such period at weighted average daily prices of $77.20, $79.95 and $79.59 per barrel, respectively, in each case before transportation costs. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended September 30, 2007 and 2006

We reported net income of $12,701,000 for the three months ended September 30, 2007, as compared to $12,517,000 for the three months ended September 30, 2006. This slight increase in net income was due primarily to a 16% increase in net production to 440,439 BOE from 380,042 BOE, and an 8% increase in realized BOE prices to $68.05 from $63.21, for the quarter ended September 30, 2007 as compared to the same period in 2006, respectively, partially offset by increases in lease operating, production taxes and general and administrative expenses.

Oil and Gas Revenues. For the three months ended September 30, 2007, we reported oil and gas revenues of $29,972,000 compared to oil and gas revenues of $24,024,000 during the same period in 2006. This $5,948,000, or 25%, increase in revenues is primarily attributable to a 16% increase in net production to 440,439 BOE from 380,042 BOE, and an 8% increase in realized BOE prices to $68.05 from $63.21, for the quarter ended September 30, 2007 as compared to the same period in 2006, respectively. Production for 2006 period was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

The following table summarizes our oil and natural gas production and related pricing for the three months ended September 30, 2007 and 2006:

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006
Oil production volumes (MBbls)	404	320
Gas production volumes (MMcf)	218	360
Average oil price (per Bbl)	$ 70.46	$ 67.67
Average gas price (per Mcf)	$ 6.88	$ 6.58

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $4,008,000 for the three months ended September 30, 2007 from $2,954,000 for the same period in 2006. Since our WCBB facilities continued to be shut in until late in the first quarter of 2006 due to the impact of Hurricane Rita some of the costs that would normally have been associated with our lease operating expenses were instead spent on ongoing restoration and repair activities during the third quarter of 2006. Lease operating expenses for the third quarter of 2007 increased due to increases in labor costs and non-recurring repairs and were partially offset by a reduction in lease operating expenses attributable to our interest in the Marquiss field which we sold during February 2007.

Production Taxes. Production taxes increased to $3,547,000 for the three months ended September 30, 2007 from $2,936,000 for the same period in 2006. This increase was directly related to a 25% increase in oil and gas revenues as a result of the increase in production and an 8% increase in our average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $7,845,000 for the three months ended September 30, 2007, and consisted of $7,727,000 in depletion on oil and natural gas properties and $118,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $4,488,000 for the three months ended September 30, 2006. This increase was due primarily to an increase in our production, an increase in our oil and natural gas property costs associated with our 2007 drilling programs and an increase in our future development costs.

General and Administrative Expenses. Net general and administrative expenses increased to $1,192,000 for the three months ended September 30, 2007 from $717,000 for the same period in 2006. This increase was due primarily to general increases in payroll costs and related benefits, increases in the total number of employees and increases in the effect of SFAS No. 123(R), *Share Based Payment,* preliminary work on our year-end reserve report and a decrease in general and administrative reimbursements from our affiliates. This increase was partially offset by a decrease in legal expenses and an increase in general and administrative overhead related to our exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense decreased to $138,000 for the three months ended September 30, 2007 from $149,000 for the same period in 2006. Although there was a larger obligation at the beginning of 2007 than there was at the beginning of 2006 resulting from the addition of future abandonment obligations on new wells drilled during 2006, the effect of the increase on the larger obligations was more than offset by the effect of the sale of the Marquiss properties in February 2007.

Interest Expense. Interest expense increased slightly to $654,000 for the three months ended September 30, 2007 from $644,000 for the same period in 2006. Total weighted debt outstanding under our facilities with Bank of America was $27.0 million for the three months ended September 30, 2007 and $18.4 million as of the same period in 2006 and total debt outstanding under these facilities was $34.5 million as of September 30, 2007 and $26.4 million as of the same date in 2006. Interest expense during the 2006 period also included $153,000 of interest related to a cash call for Grizzly and $35,000 of interest relating to a sales tax audit.

Income Taxes. As of September 30, 2007, we had a net operating loss carry forward of approximately $95.9 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, 2007, a valuation allowance of $25.6 million had been provided for deferred tax assets. We had $4,000 of income tax expense for the three months ended September 30, 2007 related to payment of alternative minimum tax due for 2006.

Comparison of the Nine Months Ended September 30, 2007 and 2006

We reported net income of $29,558,000 for the nine months ended September 30, 2007, compared to $22,404,000 for the nine months ended September 30, 2006. This 31% increase in net income was due primarily to a 74% increase in net production to 1,204,175 BOE for the nine months ended September 30, 2007 from 691,480 BOE for the same period in 2006.

Oil and Gas Revenues. For the nine months ended September 30, 2007, we reported oil and gas revenues of $75,353,000, compared to oil and gas revenues of $42,822,000 during the same period in 2006. This $32,531,000, or 76%, increase in revenues is primarily attributable to a 74% increase in net production to 1,204,175 BOE for the nine months ended September 30, 2007 from 691,480 BOE for the same period in 2006. Production in the 2006 period was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

The following table summarizes our oil and natural gas production and related pricing for the nine months ended September 30, 2007 and 2006:

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Oil production volumes (MBbls)	1,116	599
Gas production volumes (MMcf)	531	552
Average oil price (per Bbl)	$ 63.97	$ 65.74
Average gas price (per Mcf)	$ 7.51	$ 6.19

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $11,127,000 for the nine months ended September 30, 2007 from $6,559,000 for the same period in 2006. Since our WCBB facilities continued to be shut in until late in the first quarter of 2006 due to the impact of Hurricane Rita some of the costs that would have normally been associated with our lease operating expenses were instead spent on ongoing restoration and repair activities during the nine months ended September 30, 2006. In addition, lease operating expenses for the nine months ended September 30, 2007 increased due to increases in labor costs and non-recurring repairs and were partially offset by a reduction in lease operating expenses attributable to our interest in the Marquiss field which we sold during February 2007.

Production Taxes. Production taxes increased to $9,017,000 for the nine months ended September 30, 2007 from $5,422,000 for the same period in 2006. This increase was directly related to a 76% increase in oil and gas revenues as a result of the increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $20,128,000 for the nine months ended September 30, 2007, and consisted of $19,790,000 in depletion on oil and natural gas properties and $338,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $8,224,000 for the nine months ended September 30, 2006. This increase was due primarily to an increase in our production, an increase in our oil and natural gas property costs associated with our 2006 and 2007 drilling programs and an increase in our future development costs.

General and Administrative Expenses. Net general and administrative expenses increased to $3,427,000 for the nine months ended September 30, 2007 from $2,232,000 for the same period in 2006. This increase was due primarily to general increases in payroll costs and related benefits, increases in the total number of employees and increases in the effect of SFAS No. 123(R), *Share Based Payment.* These increases were partially offset by an increase in general and administrative reimbursements from our affiliates and a decrease in legal expenses and corporate fees.

Accretion Expense. Accretion expense decreased to $415,000 for the nine months ended September 30, 2007 from $447,000 for the same period in 2006. Although there was a larger obligation at the beginning of 2007 than there was at the beginning of 2006 resulting from the addition of future abandonment obligations on new wells drilled during 2006, the effect of the increase on the larger obligations was more than offset by the effect of the sale of the Marquiss properties in February 2007.

Interest Expense. Interest expense increased to $1,979,000 for the nine months ended September 30, 2007 from $1,312,000 for the same period in 2006 due to an increase in average debt outstanding. Total weighted debt outstanding under our facilities with Bank of America was $27.9 million for the nine months ended September 30, 2007 and $15.6 million as of the same period in 2006. In addition, during July 2006 we entered into a new $5.0 million term loan agreement with Bank of America. As a result, during the nine months ended September 30, 2007 the Company recognized a full nine months of interest in the amount of $298,000 as compared to only $26,000 for the same period in 2006. Total debt outstanding under our facilities with Bank of America was $34.5 million as of September 30, 2007 and $26.4 million as of the same date in

2006.

Table of Contents

Income Taxes. As of September 30, 2007, we had a net operating loss carry forward of approximately $95.9 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, 2007, a valuation allowance of $25.6 million had been provided for deferred tax assets. We had only a slight income tax expense of $57,000 during the nine months ended September 30, 2007 related to the payment of alternative minimum taxes due for 2006. Although we have substantial net operating loss carryforwards, these cannot be used to offset alternative minimum tax liabilities.

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. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and gas production. During the nine months ended September 30, 2006, recoveries under our insurance coverages also provided a significant source of funds due to damage from Hurricane Rita in September 2005 and the resulting interruption of our business during the fourth quarter of 2005 and the six months ended June 2006.

Net cash flow provided by operating activities was $47,236,000 for the nine months ended September 30, 2007 as compared to net cash flow provided by operating activities of $27,934,000 for the same period in 2006. This increase was primarily the result of an increase in cash receipts from our oil and gas purchasers due to a 74% increase in net production, partially offset by increases in cash paid for lease operating expenses and production taxes.

Net cash used in investing activities for the nine months ended September 30, 2007 was $115,326,000 as compared to $53,155,000 for the same period in 2006. During the nine months ended September 30, 2007, we spent $102,757,000 in additions to oil and natural gas properties, of which $63,475,000 was spent on our 2007 drilling program, $13,222,000 was spent on expenses attributable to the wells drilled during 2006, $9,268,000 was spent on our new Hackberry barge facilities, $2,834,000 was spent on additions to oil and natural gas properties due to Hurricane Rita, with the remainder attributable mainly to capitalized general and administrative expenses. During the nine months ended September 30, 2007, we used cash from operations, proceeds from the sale of 4,047,500 shares of our common stock and borrowings under our credit facility to fund our investing activities.

Net cash provided by financing activities for the nine months ended September 30, 2007 was $63,235,000 as compared to $29,199,000 for the same period in 2006. The 2007 amount provided by financing activities is primarily attributable to borrowings of $46,500,000 under our credit facility with Bank of America and aggregate proceeds of approximately $62,826,000 from the sale of shares of our common stock in February 2007, May 2007 and July 2007, after deducting the underwriting discount and offering expenses, and $868,000 from the exercise of stock options. Net proceeds were used to pay down $46,328,000 of outstanding existing debt under our credit facility with Bank of America and for other general corporate purposes. The 2006 amount provided by financing activities is attributable to draws of $29,841,000 on our credit facility with Bank of America and proceeds before offering costs of $10,451,000 from the issuance of common stock in our May 2006 underwritten public offering and $45,000 from the exercise of stock options.

Issuance of Equity. In January 2007, we sold 1,150,000 shares of our common stock in an underwritten offering at an offering price to the public of $11.92 per share. In connection with the offering, we granted the underwriter an option to purchase up to an additional 172,500 shares of our common stock to cover any over-allotments, which the underwriter exercised in full. We received the net proceeds of approximately $15.3 million from the sale of these shares on February 5, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down outstanding debt under our credit facility.

In May 2007, we sold 1,500,000 shares of our common stock in an underwritten offering at an offering price to the public of $16.00 per share. In connection with the offering, we granted the underwriter an option to purchase up to an additional 225,000 shares of our common stock to cover any over-allotments, which the underwriter exercised in full. We received the net proceeds of approximately $26.8 million from the sale of these shares on May 22, 2007 after deducting the underwriting discount and before offering expenses. These net proceeds were used to pay down outstanding debt under our credit facility.

In July 2007, we sold 1,000,000 shares of our commons stock in an underwritten offering at an offering price to the public of $22.00 per share. We received the net proceeds of approximately $21.2 million from our sale of these shares on July 25, 2007 after deducting the underwriting discount and before offering expenses.

Credit Facility. On March 11, 2005, we entered into a three-year secured reducing credit agreement, as amended, providing for a revolving credit facility with Bank of America, N.A. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. The credit facility has a term of three years and all principal amounts of revolving loans outstanding under the credit facility, together with all accrued and unpaid interest and fees will be due and payable on March 11, 2008. The maturity date was subsequently amended to March 31, 2009. We make quarterly interest payments on amounts borrowed under the facility, which amounts bear interest at Bank of America prime plus 0.25% (8.5% at September 30, 2007). Our obligations under the credit facility are collateralized by a lien on substantially all of our Louisiana oil and gas assets.

The credit facility contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of current assets to current liabilities may not be less than 1.00 to 1.00; (b) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period may not be greater than 2.00 to 1.00; and (c) 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 not in compliance with the current ratio covenant at September 30, 2007; however, a waiver has been obtained from the lender through October 1, 2008. As of September 30, 2007, approximately $30.0 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. We have used the proceeds of our borrowings under the credit facility for the exploration of our oil and natural gas properties and other capital expenditures, acquisition opportunities, replacement of facilities and equipment due to Hurricane Rita and for other general corporate purposes.

On July 10, 2006, we entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. Amounts borrowed bear interest at Bank of America prime (8.25% at September 30, 2007). We make quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement are collateralized by a lien on the compressor units. As of September 30, 2007, approximately $4.5 million was outstanding under this agreement, of which $714,000 and $3,757,000 are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on our accompanying consolidated balance sheet.

Building Loans. We have three loans associated with two of our buildings. One loan, in the original principal amount of $115,000, related to a building in Lafayette, Louisiana, that we purchased in 1996 to be used as our Louisiana headquarters. This loan bore interest at the rate of 5.75% per annum. We repaid this loan in full during the third quarter of 2007. In addition, in June 2004 we purchased the office building we occupy in Oklahoma City, Oklahoma for $3.7 million. One of the two loans associated with this building, with an original principal amount of $389,000, matured in March 2006 and bore interest at a rate of 6% per annum. The other loan associated with this building, with an original principal amount of $3.0 million, matures in June 2011 and bears interest at a rate of 6.5% per annum. All building loans require monthly interest and principal payments and are collateralized by the respective land and buildings.

Capital Expenditures. Our recent capital commitments have been primarily for the development of our proved reserves and to increase our net acreage position in Grizzly Oil Sands ULC. 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 and (2) explore other acquisition opportunities. We have upgraded our infrastructure and our existing facilities 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 our principal property, WCBB. The reprocessed data enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the field, thus creating a portfolio of new drilling opportunities.

Table of Contents

In our December 31, 2006 reserve report, 76% of our net reserves were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

Our inventory of prospects includes approximately 118 drilling locations at WCBB. The drilling schedule used in our December 31, 2006 reserve report anticipates that all of those wells will be drilled by 2016. From January 1, 2007 through November 1, 2007, we drilled 22 wells and recompleted 49 existing wells at our WCBB field. We currently intend to spend a total of approximately $60 to 65 million for drilling, recompletion and other activities in our WCBB field during 2007.

In our East Hackberry field, from January 1, 2007 through November 1, 2007, we drilled 11 wells. Currently we are drilling one well and intend to drill one to two additional wells during 2007. Total capital expenditures for our East Hackberry field are estimated at $60 million to $70 million for 2007.

During the third quarter of 2006, we purchased an approximate 25% interest in Grizzly. As of September 30, 2007, our net investment in Grizzly was approximately $22.8 million. Capital requirements in 2007 for this project are now estimated to be approximately $16-17 million, primarily for the expenses associated with our recently completed 62 well core hole drilling program and additional lease acquisitions.

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

Our total capital expenditures for 2007 are currently estimated to be $130.0 million to $140.0 million. We believe that our cash on hand, cash flow from operations, and borrowings under our credit facility will be sufficient to meet our normal recurring operating needs, debt service obligations, and our WCBB capital requirements for the next twelve months. With the added Hackberry activity or in the event we elect to further expand or accelerate our drilling programs, pursue acquisitions or accelerate our Canadian oil sands project, we will be required to obtain additional funds which we may do so 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

To mitigate the effects of commodity price fluctuations, during the second quarter of 2007, we entered into agreements to sell 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of $70.15 per barrel before transportation costs. For the period of July 2007 through May 2008, we have agreements to sell 3,500 barrels of production per day at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have agreements to sell 3,500 barrels of production per day at a weighted average daily price of $71.69 per barrel before transportation costs. For the months of July 2008 and August 2008 and the period September 2008 through December 2008, we have entered into forward sales contracts for the sale of 2,000 barrels of production per day in each such period at weighted average daily prices of $77.20, $79.95 and $79.59 per barrel, respectively, in each case before transportation costs. Under these agreements we have committed to deliver approximately 66% of our estimated production for June through December 2007. 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 contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004 to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of September 30, 2007, the plugging and abandonment trust totaled approximately $3,078,000, including interest received during 2007 of approximately $100,000. We have plugged 231 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our minimum plugging obligation through March 31, 2007.

24

New Accounting Pronouncements

We adopted FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109,* as of January 1, 2007. The adoption of this Interpretation had no effect on our consolidated financial statements. We are subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. Our 2003 2006 U.S. federal and state income tax returns remain open to examination by the Internal Revenue Service. We are continuing our practice of recognizing interest and/or penalties related to income tax matters as general and administrative expenses.

SFAS 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption permitted. We are currently assessing the impact, if any, of the adoption of SFAS 157.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which we elect the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided we also elect to apply the provisions of SFAS No. 157, *Fair Value Measurements*, at the same time. We are currently assessing the impact, if any, of the adoption of SFAS No. 159.

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, over the last three years, the West Texas Intermediate posted price for crude oil has ranged from a low of $40.16 per barrel, or bbl, in December 2004 to a high of $82.55 per bbl in October 2007. The Henry Hub spot market price of natural gas has ranged from a low of $4.20 per million British thermal units, or MMBtu, in October 2006 to a high of $13.93 per MMBtu in October 2005. Until recently, these prices have generally been at historically high levels. On September 30, 2007, the West Texas Intermediate posted price for crude oil was $78.40 per bbl for crude oil and the Henry Hub spot market price of natural gas was $6.38 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations. To mitigate the effects of commodity price fluctuations, in the second quarter of 2007, we entered into forward sales contracts to deliver 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of $70.15 per barrel before transportation costs. For the period of July 2007 through May 2008, we have committed to 3,500 barrels of production per day at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have agreements to sell 3,500 barrels of production per day at a weighted average daily price of $71.69 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 66% of our estimated production for June through December 2007. For the months of July 2008 and August 2008 and the period September 2008 through December 2008, we have entered into forward sales contracts for the

sale of 2,000 barrels of production per day in each such period at weighted average daily prices of $77.20, $79.95 and $79.59 per barrel, respectively, in each case before transportation costs. Such arrangements, however, may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

Our credit facility and term loan with Bank of America are structured under floating rate terms and, as such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. Borrowings under our revolving credit facility with Bank of America bear interest at Bank of America prime plus 0.25% (8.5% at September 30, 2007). Borrowings under our term loan with Bank of America bear interest at Bank of America prime (8.25% at September 30, 2007). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $345,000 per year, based on an aggregate of $34.5 million outstanding under our credit facilities as of September 30, 2007. As of September 30, 2007, 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 we are required to disclose 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 our management, including the Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

As of September 30, 2007, an evaluation was performed under the supervision and with the participation of our management, including the 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 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, 2007, 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 the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In our Quarterly Report on Form 10-Q for the second quarter of 2007, filed with the Securities and Exchange Commission on August 14, 2007, we provided information regarding certain pending lawsuits. This included information relating to an accident that occurred in October 2006 north of our production facilities in the West Cote Blanche Bay field in Southern Louisiana involving a tug boat owned by 4-K Marine LLC and two barges owned by Athena Construction LLC (Athena) that were performing work on our behalf. The accident resulted in a rupture of an underwater natural gas pipeline, subsequent fire damage to the vehicles and six fatalities. Since the filing of the Form 10-Q, a new lawsuit has been filed on October 15, 2007 by Brian Dumesnil in the 16th Judicial District Court for the Parish of St. Mary, Louisiana against Gulfport, Chevron USA, Inc., Chevron Texaco Pipeline Holdings, Inc., Chevron Natural Gas Services, Inc., Diamondback Energy Services LLC, an affiliate of Gulfport, and the estate of Timothy Tauzin, the deceased captain of the tug boat involved in the accident. Mr. Dumesnil was employed by Athena and was on the Athena barge at the time of the accident. He is seeking unspecified sums of money as a result of the alleged negligence of defendants and injuries incurred following the October 2006 accident. We are currently working to respond to this matter. No deadlines have been set with respect to this lawsuit. In addition, both the Hummel and Davis suits were stayed by the court on September 6, 2007.

In addition, since our last report on Form 10-Q, we filed a motion for summary judgment on October 5, 2007 in a lawsuit filed in November 2006 by Cudd Pressure Control, Inc. against Gulfport and Great White Pressure Control LLC, one of our affiliates. The plaintiff has until November 15, 2007 to respond.

Further, since our last report on Form 10-Q, we agreed to respond to a putative class action lawsuit, filed in July 2007 by Robotti & Company, LLC, following notification from the plaintiff.

Table of Contents

In addition, Gulfport is currently working with the Attorney General of the State of Louisiana to finalize the settlement agreement relating to the Louisiana State Mineral Board s dispute of Gulfport s royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts.

Litigation is inherently uncertain and its outcome cannot be predicted at this time. Adverse decisions in one or more of the above referenced matters could have a material adverse effect on our financial condition or results of operations.

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

Except as discussed herein, this report does not modify, amend or update in any way the description of any legal proceedings or any other item or disclosures set forth in our Form 10-Q for the second quarter of 2007.

ITEM 1A. RISK FACTORS.

In addition to the risk factors previously disclosed in our Annual Report on Form 10-KSB for the year ended December 31, 2006, we have added the following new risk factor:

There are numerous uncertainties inherent in estimating quantities of bitumen reserves and resources and no assurance can be given that indicated level of reserves or recovery of bitumen will be realized.

There are numerous uncertainties inherent in estimating quantities of bitumen reserves and resources, including many factors beyond our or Grizzly s control, and no assurance can be given that the indicated level of reserves or recovery of bitumen will be realized. In general, estimates of economically recoverable bitumen reserves and the future net cash flow from such reserves are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves. Reserve and resource estimates may require revision based on actual production experience. Reserve and resources estimates are determined with reference to assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. No assurance can be provided as to the gravity or quality of bitumen to be produced from Grizzly s lands.

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 nine months ended September 30, 2007, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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

None.

ITEM 5. OTHER INFORMATION

(a) None.

(b) None.

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	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	Second Amendment to Credit Agreement, dated as of July 19, 2007, between the Company and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
10.2	Note dated July 19, 2007 issued by the Company for the benefit of Bank of America, N.A. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	

	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.

* Filed herewith.

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 13, 2007

GULFPORT ENERGY CORPORATION

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

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

Table of Contents

Exhibit Index

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	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	Second Amendment to Credit Agreement, dated as of July 19, 2007, between the Company and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
10.2	Note dated July 19, 2007 issued by the Company for the benefit of Bank of America, N.A. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.

* Filed herewith.