GULFPORT ENERGY CORP
Form 10-Q
August 05, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

FOR THE QUARTERLY PERIOD ENDED June 30, 2011

OR

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

Commission File Number 000-19514

Gulfport Energy Corporation

(Exact Name of Registrant As Specified in Its Charter)

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

(405) 848-8807

(Registrant Telephone Number, Including Area Code)

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

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

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

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

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

As of August 1, 2011, 50,930,032 shares of common stock were outstanding.

GULFPORT ENERGY CORPORATION

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 4,678,000	$ 2,468,000
Accounts receivable - oil and gas	19,872,000	14,952,000
Accounts receivable - related parties	9,558,000	573,000
Prepaid expenses and other current assets	1,923,000	1,732,000
Total current assets	36,031,000	19,725,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $59,734,000 and $16,778,000 excluded from amortization in 2011 and 2010, respectively	859,647,000	747,344,000
Other property and equipment	7,701,000	7,609,000
Accumulated depletion, depreciation, amortization and impairment	(538,692,000)	(512,822,000)
Property and equipment, net	328,656,000	242,131,000
Other assets		
Equity investments	50,180,000	33,021,000
Note receivable - related party	23,895,000	20,006,000
Other assets	4,932,000	4,182,000
Total other assets	79,007,000	57,209,000
Deferred tax asset	628,000	628,000
Total assets	$ 444,322,000	$ 319,693,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 49,690,000	$ 41,155,000
Asset retirement obligation - current	635,000	635,000
Short-term derivative instruments	3,431,000	4,720,000
Current maturities of long-term debt	137,000	2,417,000
Total current liabilities	53,893,000	48,927,000
Asset retirement obligation - long-term	10,982,000	10,210,000
Long-term debt, net of current maturities	32,215,000	49,500,000
Total liabilities	97,090,000	108,637,000
Commitments and contingencies (Note 13)		
Preferred stock, $.01 par value; 5,000,000 authorized,		

30,000 authorized as redeemable 12% cumulative preferred stock,		
Series A; 0 issued and outstanding		
Stockholders equity:		
Common stock - $.01 par value, 100,000,000 authorized,		
47,480,032 issued and outstanding in 2011 and 44,645,435 in 2010	475,000	446,000
Paid-in capital	381,102,000	296,253,000
Accumulated other comprehensive income (loss)	1,091,000	(1,768,000)
Retained earnings (accumulated deficit)	(35,436,000)	(83,875,000)
Total stockholders equity	347,232,000	211,056,000
Total liabilities and stockholders equity	$ 444,322,000	$ 319,693,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Revenues:				
Oil and condensate sales	$ 52,916,000	$ 27,035,000	$ 98,112,000	$ 53,295,000
Gas sales	1,512,000	1,314,000	2,232,000	1,752,000
Natural gas liquids sales	1,034,000	693,000	1,693,000	1,341,000
Other income (expense)	(515,000)	(167,000)	(768,000)	(158,000)
	54,947,000	28,875,000	101,269,000	56,230,000
Costs and expenses:				
Lease operating expenses	4,706,000	3,973,000	9,359,000	8,149,000
Production taxes	6,732,000	3,541,000	12,239,000	6,733,000
Depreciation, depletion, and amortization	13,712,000	8,688,000	25,870,000	16,613,000
General and administrative	2,119,000	1,518,000	4,175,000	2,900,000
Accretion expense	164,000	151,000	323,000	305,000
	27,433,000	17,871,000	51,966,000	34,700,000
INCOME FROM OPERATIONS:	27,514,000	11,004,000	49,303,000	21,530,000
OTHER (INCOME) EXPENSE:				
Interest expense	285,000	613,000	938,000	1,331,000
Interest income	(37,000)	(38,000)	(75,000)	(211,000)
	248,000	575,000	863,000	1,120,000
INCOME BEFORE INCOME TAXES	27,266,000	10,429,000	48,440,000	20,410,000
INCOME TAX EXPENSE:	1,000	40,000	1,000	40,000
NET INCOME	$ 27,265,000	$ 10,389,000	$ 48,439,000	$ 20,370,000
NET INCOME PER COMMON SHARE:				
Basic	$ 0.57	$ 0.24	$ 1.05	$ 0.47
Diluted	$ 0.57	$ 0.24	$ 1.04	$ 0.47
Weighted average common shares outstanding - Basic	47,454,359	43,546,237	46,097,207	43,125,016
Weighted average common shares outstanding - Diluted	47,898,665	43,976,009	46,548,414	43,470,013

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Common Stock		Additional	Accumulated Other	Retained Earnings	Total
	Shares	Amount	Paid-in Capital	Comprehensive Income (Loss)	(Accumulated Deficit)	Stockholders Equity
Balance at January 1, 2011	44,645,435	$ 446,000	$ 296,253,000	$ (1,768,000)	$ (83,875,000)	$ 211,056,000
Net income					48,439,000	48,439,000
Other Comprehensive Income:						
Foreign currency translation adjustment				1,570,000		1,570,000
Change in fair value of derivative instruments				(722,000)		(722,000)
Reclassification of settled contracts				2,011,000		2,011,000
Total Comprehensive Income						51,298,000
Stock Compensation			453,000			453,000
Issuance of Common Stock in public offering, net of related expenses	2,760,000	28,000	84,000,000			84,028,000
Issuance of Common Stock through exercise of options	41,000	1,000	396,000			397,000
Issuance of Restricted Stock	33,597					
Balance at June 30, 2011	47,480,032	$ 475,000	$ 381,102,000	$ 1,091,000	$ (35,436,000)	$ 347,232,000
Balance at January 1, 2010	42,696,409	$ 427,000	$ 273,901,000	$ (18,039,000)	$ (131,238,000)	$ 125,051,000
Net income					20,370,000	20,370,000
Other Comprehensive Income:						
Foreign currency translation adjustment				(541,000)		(541,000)
Change in fair value of derivative instruments				2,960,000		2,960,000
Reclassification of settled contracts				9,378,000		9,378,000
Total Comprehensive Income						32,167,000
Stock Compensation			233,000			233,000
Issuance of Common Stock in public offering, net of related expenses	1,668,503	17,000	21,384,000			21,401,000
Issuance of Common Stock through exercise of warrants	172,269	2,000	203,000			205,000
Issuance of Common Stock through exercise of options	2,000		7,000			7,000
Issuance of Restricted Stock	28,093					
Balance at June 30, 2010	44,567,274	$ 446,000	$ 295,728,000	$ (6,242,000)	$ (110,868,000)	$ 179,064,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2011	2010
Cash flows from operating activities:		
Net income	$ 48,439,000	$ 20,370,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount - Asset Retirement Obligation	323,000	305,000
Depletion, depreciation and amortization	25,870,000	16,613,000
Stock-based compensation expense	272,000	140,000
Loss from equity investments	958,000	270,000
Interest income - note receivable	(76,000)	(201,000)
Amortization of loan commitment fees	241,000	
Changes in operating assets and liabilities:		
Increase in accounts receivable	(4,920,000)	(2,236,000)
Increase in accounts receivable - related party	(8,985,000)	(23,000)
(Increase) decrease in prepaid expenses	(191,000)	46,000
Increase in other assets		(75,000)
Increase in accounts payable and accrued liabilities	3,470,000	156,000
Settlements of asset retirement obligation		(730,000)
Net cash provided by operating activities	65,401,000	34,635,000
Cash flows from investing activities:		
Deductions to cash held in escrow	8,000	8,000
Additions to other property, plant and equipment	(92,000)	(255,000)
Additions to oil and gas properties	(108,368,000)	(49,828,000)
Proceeds from sale of oil and gas properties	1,384,000	
Advances on note receivable to related party	(3,181,000)	(1,169,000)
Contributions to investment in Grizzly Oil Sands ULC	(15,539,000)	
Distribution from investment in Tatex Thailand II, LLC	329,000	225,000
Contribution to investment in Tatex Thailand III, LLC	(1,968,000)	(224,000)
Net cash used in investing activities	(127,427,000)	(51,243,000)
Cash flows from financing activities:		
Principal payments on borrowings	(54,565,000)	(4,425,000)
Borrowings on line of credit	35,000,000	
Loan commitment fees	(624,000)	
Proceeds from issuance of common stock, net of offering costs, and exercise of stock options	84,425,000	21,613,000
Net cash provided by financing activities	64,236,000	17,188,000
Net increase in cash and cash equivalents	2,210,000	580,000
Cash and cash equivalents at beginning of period	2,468,000	1,724,000
Cash and cash equivalents at end of period	$ 4,678,000	$ 2,304,000

Supplemental disclosure of cash flow information:				
Interest payments	$	778,000	$	1,071,000
Supplemental disclosure of non-cash transactions:				
Capitalized stock based compensation	$	181,000	$	93,000
Asset retirement obligation capitalized	$	449,000	$	765,000
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$	938,000	$	(300,000)
Foreign currency translation gain (loss) on note receivable - related party	$	632,000	$	(241,000)

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

These consolidated financial statements have been prepared by Gulfport Energy Corporation (the Company or Gulfport) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission, and reflect all adjustments which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods, on a basis consistent with the annual audited consolidated financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to such rules and regulations, although the Company believes that the disclosures are adequate to make the information presented not misleading. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the summary of significant accounting policies and notes thereto included in the Company s most recent annual report on Form 10-K. Results for the three month and six month periods ended June 30, 2011 are not necessarily indicative of the results expected for the full year.

1. ACQUISITION

In February 2011, the Company entered into agreements to acquire certain leasehold interests located in the Utica Shale in Ohio. The agreements also grant the Company an exclusive right of first refusal for a period of six months on certain additional tracts leased by the seller. Affiliates of Gulfport have agreed to participate with the Company on a 50/50 basis in the acquisition of all leases described above. Gulfport will be the operator on this acreage in the Utica Shale. As of June 30, 2011, the Company had acquired leasehold interests in approximately 33,000 gross (16,500 net) acres in the Utica Shale for approximately $37.9 million. Gulfport funded these transactions with a portion of the proceeds from a 2.8 million share offering of the Company s common stock completed in March of 2011. The Company received net proceeds (before offering expenses) of approximately $84.3 million from the equity offering, as discussed below in Note 7. The Company also has commitments which will increase its acreage position in the Utica Shale to approximately 115,000 gross (57,500 net) leasehold acres. The Company intends to continue to pursue opportunities in this area.

2. ACCOUNTS RECEIVABLE RELATED PARTY

Included in the accompanying June 30, 2011 and December 31, 2010 consolidated balance sheets are amounts receivable from related parties 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 these related parties. These services are solely administrative in nature and for entities in which the Company has no property interests. The amounts reimbursed to the Company for these services are for the purpose of Gulfport recovering costs associated with the services and do not include the assessment of any fees or other amounts beyond the estimated costs of performing such services. The receivables also include amounts billed by the Company as operator of the Company s Colorado and Ohio oil and gas properties. At June 30, 2011 and December 31, 2010, these receivable amounts totaled $9,558,000 and $573,000, respectively. No amounts were reimbursed for general and administrative functions during the three months and six months ended June 30, 2011 and 2010 with the exception of amounts billed under the acquisition team agreement discussed below.

The Company is a party to an administrative service agreement with Great White Energy Services LLC. Under the agreement, the Company s services include accounting, human resources, legal and technical support. The services provided and the fees for such services can be amended by mutual agreement of the parties. The administrative service agreement had an initial three-year term, and upon expiration of that term the agreement has continued on a month-to-month basis. The administrative service agreement is terminable by either party at any time with at least 30 days prior written notice.

The Company is also a party to administrative service agreements with Stampede Farms LLC, Grizzly Oil Sands ULC (Grizzly), Everest Operations Management LLC and Tatex Thailand III, LLC. Under the agreements, the Company s services include professional and technical support. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements had an initial two-year term, and has continued thereafter on a month-to-month basis. Each agreement may be cancelled by either party to such agreement with at least 60 days prior written notice and is also terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company s administrative agreement with Grizzly was terminated effective December 31, 2010.

Wexford Capital LP (Wexford) controls and/or owns a greater than 10% interest in each of these entities. An affiliate of Wexford owns approximately 17% of Gulfport s outstanding common stock.

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

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

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of June 30, 2011 and December 31, 2010 are as follows:

	June 30, 2011	December 31, 2010
Oil and natural gas properties	$ 859,647,000	$ 747,344,000
Office furniture and fixtures	3,369,000	3,277,000
Building	4,049,000	4,049,000
Land	283,000	283,000
Total property and equipment	867,348,000	754,953,000
Accumulated depletion, depreciation, amortization and impairment	(538,692,000)	(512,822,000)
Property and equipment, net	$ 328,656,000	$ 242,131,000

Included in oil and natural gas properties at June 30, 2011 is the cumulative capitalization of $20,914,000 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 $1,411,000 and $2,788,000 for the three months and six months ended June 30, 2011, respectively, and $1,026,000 and $1,971,000 for the three months and six months ended June 30, 2010, respectively.

At June 30, 2011, approximately $5,645,000 of oil and gas properties related to the Company s Belize properties is excluded from amortization as they relate to non-producing properties. In addition, approximately $9,245,000 of non-producing leasehold costs resulting from the Company s acquisition of West Texas Permian properties, $301,000 of non-producing leasehold costs related to the Company s Bakken properties and $3,051,000 of non-producing leasehold costs related to the Company s Colorado properties are excluded from amortization at June 30, 2011. Approximately $1,088,000 of non-producing leasehold costs related to the Company s Southern Louisiana assets, $40,124,000 of non-producing leasehold costs related to the Company s Ohio leasehold costs and $280,000 of non-producing leasehold costs related to other projects are also excluded from amortization at June 30, 2011.

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

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A reconciliation of the asset retirement obligation for the six months ended June 30, 2011 and 2010 is as follows:

	June 30, 2011	June 30, 2010
Asset retirement obligation, beginning of period	$ 10,845,000	$ 10,153,000
Liabilities incurred	449,000	765,000
Liabilities settled		(730,000)
Accretion expense	323,000	305,000
Asset retirement obligation as of end of period	11,617,000	10,493,000
Less current portion	635,000	635,000
Asset retirement obligation, long-term	$ 10,982,000	$ 9,858,000

4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of June 30, 2011 and December 31, 2010.

	June 30, 2011	December 31, 2010
Investment in Tatex Thailand II, LLC	$ 1,572,000	$ 1,907,000
Investment in Tatex Thailand III, LLC	6,490,000	4,660,000
Investment in Grizzly Oil Sands ULC	42,118,000	26,454,000
	$ 50,180,000	$ 33,021,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC (Tatex) at a cost of $2,400,000. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (APICO), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering two million acres which includes the Phu Horm Field. During the six months ended June 30, 2011, Gulfport received $329,000 in distributions, bringing its total investment in Tatex to $1,572,000. The loss on equity investment related to Tatex was immaterial for the six months ended June 30, 2011 and 2010.

Tatex Thailand III, LLC

During the first quarter of 2008, the Company purchased a 5% ownership interest in Tatex Thailand III, LLC (Tatex III) at a cost of $850,000. In December 2009, the Company purchased an additional approximately 12.9% ownership interest at a cost of approximately $3,385,000 bringing its total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. During the six months ended June 30, 2011, Gulfport paid $1,968,000 in cash calls, bringing its total investment in Tatex III (including previous investments) to $6,490,000. The Company recognized a loss on equity investment of $138,000 and $104,000 for the six months ended June 30, 2011 and 2010, respectively, which is included in other income (expense) in the consolidated statements of operations.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly, a Canadian unlimited liability company, for approximately $8,199,000. The remaining interests in Grizzly are owned by entities controlled by Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has drilled core holes and water supply test wells in nine separate lease blocks for feasibility of oil production and conducted a seismic program. In March 2010, Grizzly filed an application in Alberta, Canada for the development of an 11,300 barrel per day SAGD facility at Algar Lake. As of June 30, 2011, Gulfport s net investment in Grizzly was $42,118,000. During the six months ended June 30, 2011, the Company paid $15,539,000 in cash calls. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was increased by $232,000 and $938,000 as a result of a currency translation gain for the three months and six months ended June 30, 2011, respectively. The Company recognized a loss on equity investment of $558,000 and $813,000 for the three months and six months ended June 30, 2011, respectively, and $194,000 and $165,000 for the three months and six months ended June 30, 2010, respectively, which is included in other income (expense) in the consolidated statements of operations.

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The Company, through its wholly owned subsidiary Grizzly Holdings Inc., entered into a loan agreement with Grizzly effective January 1, 2008, under which Grizzly may borrow funds from the Company. Borrowed funds initially bore interest at LIBOR plus 400 basis points and had an original maturity date of December 31, 2012. Effective April 1, 2010, the loan agreement was amended to modify the interest rate to 0.69% and change the maturity date to December 31, 2011. Effective October 15, 2010, the loan agreement was further amended to change the maturity date to December 31, 2012. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The Company loaned Grizzly approximately $3,181,000 during the six months ended June 30, 2011. The Company recognized interest income of approximately $40,000 and $76,000 for the three months and six months ended June 30, 2011, respectively, and $29,000 and $201,000 for the three months and six months ended June 30, 2010, respectively, which is included in interest income in the consolidated statements of operations. The note balance was increased by approximately $169,000 and $632,000 as a result of a currency translation gain for the three months and six months ended June 30, 2011, respectively. The total $23,895,000 due from Grizzly at June 30, 2011 is included in note receivable related party on the accompanying consolidated balance sheets.

5. OTHER ASSETS

Other assets consist of the following as of June 30, 2011 and December 31, 2010:

	June 30, 2011	December 31, 2010
Plugging and abandonment escrow account on the WCBB properties (Note 13)	$ 3,121,000	$ 3,129,000
Certificates of deposit securing letter of credit	275,000	275,000
Prepaid drilling costs	45,000	7,000
Loan commitment fees	1,487,000	767,000
Deposits	4,000	4,000
	$ 4,932,000	$ 4,182,000

6. LONG-TERM DEBT

A breakdown of long-term debt as of June 30, 2011 and December 31, 2010 is as follows:

	June 30, 2011	December 31, 2010
Revolving credit agreement (1)	$ 30,000,000	$ 49,500,000
Building loans (2)	2,352,000	2,417,000
Less: current maturities of long term debt	(137,000)	(2,417,000)
Debt reflected as long term	$ 32,215,000	$ 49,500,000

Maturities of long-term debt as of June 30, 2011 are as follows:

2012	$ 137,000
2013	146,000
2014	154,000
2015	30,163,000
2016	1,752,000
Thereafter	
Total	$ 32,352,000

(1) On September 30, 2010, the Company entered into a $100.0 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association (Amegy Bank). This revolving credit facility initially matured on September 30, 2013 and had a borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. The credit agreement is secured by substantially all of the Company s assets. The Company s wholly-owned subsidiaries guarantee the obligations of the Company under the credit agreement.

On May 3, 2011, the Company entered into a first amendment to the revolving credit agreement with The Bank of Nova Scotia, Amegy Bank, Key Bank National Association (Key Bank) and Société Générale. Pursuant to the terms of the first amendment, Key Bank and Société Générale were added as additional lenders, the maximum amount of the facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by the Company under the credit agreement were decreased, and the maturity date was extended until May 3, 2015. As of June 30, 2011, approximately $30.0 million was outstanding under the credit agreement, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet.

Advances under the credit agreement, as amended, may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.00% to 1.75%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.00% to 2.75%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At June 30, 2011, amounts borrowed under the credit agreement bore interest at the Eurodollar rate (2.44%).

The credit agreement contains customary negative covenants including, but not limited to, restrictions on the Company s and its subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. The Company was in compliance with all covenants at June 30, 2011.

(2) In June 2004, the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while a second loan was scheduled to mature in June 2011. The Company entered into a new building loan agreement in March 2011 to refinance the $2.4 million outstanding at that time. The new agreement extends the maturity date of the building loan to February 2016 and reduces the interest rate from 6.5% per annum to 5.82% per annum. The new building loan requires monthly interest and principal payments of approximately $22,000 and is collateralized by the Oklahoma City office building and associated land.

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

Restricted Stock

On May 3, 2011, the Company granted 106,666 shares of restricted common stock of the Company to employees of the Company at a fair value of approximately $3,234,000. The shares vest annually over five years beginning on June 17, 2011. All shares of restricted common stock of the Company were granted under the Amended and Restated 2005 Stock Incentive Plan.

Sale of Common Stock

On March 30, 2011, the Company completed the sale of an aggregate of 2,760,000 shares of its common stock in an underwritten public offering at a public offering price of $32.00 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $84.3 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used the net proceeds from the equity offering to fund the Company s Utica Shale acquisition as discussed in Note 1 and for general corporate purposes. Pending the application of the Company s net proceeds for such purposes, the Company repaid all of its outstanding indebtedness under its revolving credit agreement.

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8. STOCK-BASED COMPENSATION

During the three months and six months ended June 30, 2011, the Company s stock-based compensation expense was $325,000 and $453,000, respectively, of which the Company capitalized $130,000 and $181,000, respectively, relating to its exploration and development efforts. During the three months and six months ended June 30, 2010, the Company s stock based compensation expense was $108,000 and $233,000, respectively, of which the Company capitalized $43,000 and $93,000, respectively, relating to its exploration and development efforts. Stock based compensation included in general and administrative expense reduced basic and diluted earnings per share by $0.00 and $0.01 each for the three months and six months ended June 30, 2011, and $0.00 and $0.00 each for the three months and six months ended June, 30, 2010, respectively. Options and restricted common stock are reported as share based payments and their fair value is amortized to expense using the straight-line method over the vesting period. The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

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

No stock options were issued during the six months ended June 30, 2011 and 2010.

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 six months ended June 30, 2011 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2010	458,241	$ 7.23	4.48	$ 6,621,000
Granted				
Exercised	(41,000)	9.67		710,000
Forfeited/expired				
Options outstanding at June 30, 2011	417,241	$ 6.99	3.96	$ 9,471,000
Options exercisable at June 30, 2011	417,241	$ 6.99	3.96	$ 9,471,000

Unrecognized compensation expense as of June 30, 2011 related to outstanding stock options and restricted shares was $3,920,000. The expense is expected to be recognized over a weighted average period of 2.41 years.

The following table summarizes information about the stock options outstanding at June 30, 2011:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable

$3.36	217,241	3.56	217,241
$9.07	25,000	4.19	25,000
$11.20	175,000	4.42	175,000
	417,241		417,241

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The following table summarizes restricted stock activity for the six months ended June 30, 2011:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2010	113,386	$ 11.72
Granted	106,666	30.32
Vested	(33,597)	11.98
Forfeited		
Unvested shares as of June 30, 2011	186,455	$ 22.32

9. EARNINGS PER SHARE

	For the Three Months Ended June 30,					
	2011			2010		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 27,265,000	47,454,359	$ 0.57	$ 10,389,000	43,546,237	$ 0.24
Effect of dilutive securities:						
Stock options and awards		444,306			429,772	
Diluted:						
Net income	$ 27,265,000	47,898,665	$ 0.57	$ 10,389,000	43,976,009	$ 0.24

	For the Six Months Ended June 30,					
	2011			2010		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$ 48,439,000	46,097,207	$ 1.05	$ 20,370,000	43,125,016	$ 0.47
Effect of dilutive securities:						
Stock options and awards		451,207			344,997	
Diluted:						
Net income	$ 48,439,000	46,548,414	$ 1.04	$ 20,370,000	43,470,013	$ 0.47

There were no potential shares of common stock that were considered anti-dilutive during the three month and six month periods ended June 30, 2011 and 2010.

10. OTHER COMPREHENSIVE INCOME

Other comprehensive income for the three months and six months ended June 30, 2011 and 2010 is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net income	$ 27,265,000	$ 10,389,000	$ 48,439,000	$ 20,370,000
Other comprehensive income (loss):				
Change in fair value of derivative instruments	6,780,000	4,368,000	(722,000)	2,960,000
Reclassification of settled contracts	1,164,000	4,194,000	2,011,000	9,378,000
Foreign currency translation adjustment	401,000	(1,830,000)	1,570,000	(541,000)
Total comprehensive income	$ 35,610,000	$ 17,121,000	$ 51,298,000	$ 32,167,000

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11. NEW ACCOUNTING STANDARDS

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, *Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosure* (FASB ASC 820). The purpose of the amendments in this update is to create common fair value measurement and disclosure requirements between GAAP and IFRS. The amendments change certain fair value measurement principles and enhance the disclosure requirements. The amendments to FASB ASC 820 are effective for interim and annual periods beginning after December 15, 2011.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income: Presentation of Comprehensive Income,* which provides amendments to FASB ASC Topic 220, *Comprehensive Income* (FASB ASC 220). The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in stockholders equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. The amendments to FASB ASC 220 are effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively.

12. OPERATING LEASES

In October 2006, the Company began leasing the Louisiana building that it owns to an unrelated party. The cost of the building totaled approximately $217,000 and accumulated depreciation amounted to approximately $100,000 as of June 30, 2011. The lease commenced on October 15, 2006 and was extended to expire on October 14, 2011, with equal monthly installments of $10,500. The future minimum lease payments to be received are as follows:

Fiscal year ending December 31, 2011	$ 37,000

13. COMMITMENTS AND CONTINGENCIES

Plugging and Abandonment Funds

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, the Company assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company could access the trust for use in plugging and abandonment charges associated with the property, although it has not yet done so. As of June 30, 2011, the plugging and abandonment trust totaled approximately $3,121,000. At June 30, 2011, the Company had plugged 311 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Litigation

The Louisiana Department of Revenue (LDR) is disputing Gulfport s severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 to 2007. The LDR maintains that Gulfport paid approximately $1,800,000 less in severance taxes under fixed price terms than the severance taxes Gulfport would have had to pay had it paid severance taxes on the oil at the contracted market rates only. Gulfport has denied any liability to the LDR for underpayment of severance taxes and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. Gulfport has maintained its right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against Gulfport seeking $2,275,729 in severance taxes, plus interest and court costs. Gulfport filed a response denying any liability to the LDR for underpayment of severance taxes and is defending itself in the lawsuit. The LDR has taken no further action on this lawsuit since filing its petition two years ago.

In December 2010, the LDR filed two identical lawsuits against Gulfport in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney s fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by LDR in 2009, Gulfport denies all liability and will vigorously defend the lawsuit. The cases are in the early stages, and Gulfport has not yet filed a response to the recent lawsuits. Recently, the LDR filed motions to stay the lawsuits before Gulfport filed any responsive pleadings. The LDR has advised Gulfport that it intends to pursue settlement discussions with Gulfport and other similarly situated defendants in separate proceedings.

In November 2006, Cudd Pressure Control, Inc. (Cudd) filed a lawsuit against Gulfport, Great White Pressure Control LLC (Great White) and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Gulfport filed a motion for summary judgment on October 5, 2007. The court entered a final interlocutory judgment in favor of all defendants, including Gulfport, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that Gulfport conspired with the other defendants to misappropriate, and misappropriated Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, Gulfport s motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages. In 2011, the parties have continued with written discovery and production of documents. On February 15, 2011, Cudd filed a third amended petition seeking $26.5 million (based on a report prepared by its expert) plus disgorgement of $6 million in payments by Great White to the individual defendants and punitive damages. Gulfport denies these claims with respect to itself. Recently, the parties began the process of scheduling depositions and it is anticipated that the case will remain in the discovery phase for months to come.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled *Reeds et al. v. BP American Production Company et al.,* 38th Judicial District. No. 10-18714. The plaintiffs original petition for damages, which did not name Gulfport as a defendant, alleges that the plaintiffs property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants, which in addition to BP America Production Company include ExxonMobil Corporation, Shell Oil Company, ConocoPhillips Company, Sun Oil Company and Schlumberger Technology Corporation, conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, Gulfport was served with a copy of the plaintiffs first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including Gulfport, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses and damages for evaluation and remediation of any contamination that threatens groundwater. On January 21, 2011, Gulfport filed a pleading challenging the legal sufficiency of the petitions and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by Gulfport and other defendants, the plaintiffs filed a third amending petition with exhibits which expand the description of the property at issue, attach numerous aerial photos, and identify the mineral leases at issue. In response, Gulfport and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. These pleadings were heard on May 25, 2011, and the defendants legal arguments were denied. As of July 27, 2011, the court had not entered a judgment regarding its ruling. Once it does, the defendants will have 30 days to file a supervisory writ with the apellate court seeking to overturn the lower court s ruling.

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

The Company has been named as a defendant in various other litigation matters. The ultimate resolution of these matters is not expected to have a material adverse effect on the Company s financial condition or results of operations for the periods presented in the consolidated financial statements.

14. HEDGING ACTIVITIES

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

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

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During the fourth quarter of 2010, the Company entered into fixed price swap contracts for 2011 with the purchaser of the Company s WCBB oil and another financial institution. The Company will pay the counterparty the excess of the oil market price over the fixed price and will receive the excess of the fixed price over the market prices as defined in each contract. The Company s fixed price swap contracts are tied to the commodity prices on the New York Mercantile Exchange (NYMEX). The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price for oil as listed on the NYMEX West Texas Index (WTI). However, due to the geographic location of the Company s assets and the cost of transporting oil to another market, the amount that the Company receives when it actually sells its oil differs from the index price. At June 30, 2011, the Company had the following fixed price swaps in place:

	Daily Volume (Bbls/day)	Weighted Average Price
July - December 2011	2,000	$ 86.96

At June 30, 2011, the fair value of derivative liabilities related to the fixed price swaps is as follows:

	June 30, 2011
Short-term derivative instruments - liability	$ 3,431,000

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

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Amounts reclassified out of accumulated other comprehensive income into earnings as a component of oil and condensate sales for the six months ended June 30, 2011 and 2010 are presented below.

	Six months ended June 30,	
	2011	2010
Reduction to oil and condensate sales	$ (2,011,000)	$ (9,378,000)

The Company expects to reclassify $3,431,000 out of accumulated other comprehensive income into earnings as a component of oil and condensate sales during the remainder of the year ended December 31, 2011 related to fixed price swaps.

Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company did not recognize into earnings any amount related to hedge ineffectiveness for the three months and six months ended June 30, 2011 and 2010, however, the hedges could be considered ineffective in future periods.

15. FAIR VALUE MEASUREMENTS

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

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

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

Level 3 Significant inputs to the valuation model are unobservable.

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

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The following table summarizes the Company s financial assets and liabilities by FASB ASC 820 valuation level as of June 30, 2011:

	Level 1	Level 2	Level 3
Assets:			
Forward sales contracts	$	$	$
Liabilities:			
Forward sales contracts	$	$ 3,431,000	$

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

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, *Asset Retirement and Environmental Obligations* (FASB ASC 410). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 3 for further discussion of the Company s asset retirement obligations. Asset retirement obligations incurred during the six months ended June 30, 2011 were approximately $449,000.

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

16. SUBSEQUENT EVENTS

On July 15, 2011, the Company completed the sale of an aggregate of 3,450,000 shares of its common stock in an underwritten public offering at a public offering price of $28.75 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $94.7 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of the net proceeds from the equity offering to fund the Company s acquisition of leases in the Utica Shale as discussed in Note 1 and intends to use the remaining proceeds for additional Utica Shale lease acquisitions and for general corporate purposes, which may include expenditures associated with the Company s 2011 drilling programs. Pending the application of the Company s net proceeds for such purposes, the Company repaid all of its outstanding indebtedness under its revolving credit agreement.

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

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

Disclosure Regarding Forward-Looking Statements

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

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. During 2010, we acquired an acreage position in the Niobrara Formation of Western Colorado and in May 2011, we acquired our initial acreage position in the Utica Shale in Eastern Ohio and have commitments to acquire additional acreage there. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

Second Quarter 2011 Operational Highlights

- Oil and natural gas revenues increased 91% to $55.5 million for the three months ended June 30, 2011 from $29.0 million for the three months ended June 30, 2010.

- Net income increased 162% to $27.3 million for the three months ended June 30, 2011 from $10.4 million for the three months ended June 30, 2010.

- Production increased 21% to approximately 567,000 barrels of oil equivalent, or BOE, for the three months ended June 30, 2011 from approximately 468,000 BOE for the three months ended June 30, 2010.

- During the three months ended June 30, 2011, we drilled 25 gross wells and recompleted 23 gross wells.

- As of June 30, 2011, we had acquired leasehold interests in approximately 33,000 gross (16,500 net) acres in the Utica Shale in Eastern Ohio. As of August 3, 2011, we had closed on additional acquisitions bringing our leasehold interests to approximately

60,000 gross (30,000 net) acres. We intend to continue to pursue opportunities in this area and have commitments which could increase our acreage position in the Utica Shale to an aggregate of approximately 115,000 gross (57,500 net) leasehold acres.

2011 Production and Drilling Activity

During the three months ended June 30, 2011, our total net production was 493,000 barrels of oil, 331,000 thousand cubic feet of gas, or Mcf, and 819,000 gallons of liquids, for a total of 567,000 BOE as compared to 402,000 barrels of oil, 297,000 Mcf of gas, and 677,000 gallons of liquids, or 468,000 BOE, for the three months ended June 30, 2010. Our total net production averaged approximately 6,234 BOE per day during the three months ended June 30, 2011 as compared to 5,139 BOE per day during the same period in 2010. The 21% increase in production is primarily related to the 2011 drilling and recompletion activities in our fields.

WCBB. From January 1, 2011 through July 31, 2011, we recompleted 39 existing wells. We also drilled 12 wells, of which nine were completed as producers, one was non-productive, one was waiting on completion and one was being drilled. During 2011, we currently intend to recomplete approximately 60 existing wells and drill 20 to 24 wells.

Aggregate net production from the WCBB field during the three months ended June 30, 2011 was 322,333 BOE, or 3,542 BOE per day, 96% of which was from oil and 4% of which was from natural gas. During July 2011, our average daily net production at WCBB was approximately 3,634 BOE, 97% of which was from oil and 3% of which was from natural gas. The increase in July 2011 production was the result of our 2011 drilling and recompletion program.

East Hackberry Field. From January 1, 2011 through July 31, 2011, we recompleted 15 existing wells. We also drilled 12 wells, of which seven were completed as producers, two were non-productive, one was waiting on completion and two were being drilled. During 2009, we entered into a two year exploration agreement with an active gulf coast operator covering approximately 2,868 net acres adjacent to our field. We are the designated operator under the agreement and will participate in proposed wells with at least a 70% working interest. We have licensed approximately 54 square miles of 3-D seismic data covering a portion of the area and are reprocessing the data.

Aggregate net production from the East Hackberry field during the three months ended June 30, 2011 was approximately 156,991 BOE, or 1,725 BOE per day, 83% of which was from oil and 17% of which was from natural gas. During July 2011, our average daily net production at East Hackberry was approximately 1,578 BOE, 87% of which was from oil and 13% of which was from natural gas. The decrease in July 2011 production was the result of the timing of drilling and completion of our second quarter wells and normal production declines.

West Hackberry Field. Aggregate net production from the West Hackberry field during the three months ended June 30, 2011 was approximately 2,448 BOE, or 27 BOE per day. During July 2011, our average daily net production at West Hackberry was approximately 34 BOE, 100% of which was from oil.

Permian Basin. On December 20, 2007, we completed the acquisition of approximately 4,100 net acres and 32 producing wells in West Texas in the Permian Basin for approximately $83.8 million, with an effective date of November 1, 2007. Subsequently, we have acquired approximately 10,600 additional net acres, bringing our total acreage position to approximately 14,700 net acres.

From January 1, 2011 to July 31, 2011, 23 gross (10.3 net) wells were drilled on this acreage, of which 11 were completed as producers, eight were waiting on completion and four wells were being drilled. We currently anticipate that 14 to 19 additional gross (7 to 9.5 net) wells will be drilled on this acreage during 2011.

Aggregate net production from the Permian field during the three months ended June 30, 2011 was approximately 75,437 BOE, or 829 BOE per day. During July 2011, average daily net production at Permian was approximately 931 BOE, of which approximately 61% was oil, 24% was natural gas liquids and 15% was natural gas. The increase in July 2011 production was the result of our 2011 drilling program.

Niobrara Formation. Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara formation in Colorado and held leases for approximately 19,000 acres as of June 30, 2011. We are in the process of permitting a 60 square mile 3-D seismic survey and expect to begin shooting in August or September 2011.

Aggregate net production from the Niobrara play during the three months ended June 30, 2011 was approximately 3,707 BOE, or 41 BOE per day. During July 2011, average daily net production in Niobrara was approximately 38 BOE.

Bakken. During 2009, we sold approximately 18,000 net acres and approximately 190 net BOEPD of production for approximately $18.8 million. As of June 30, 2011, we held approximately 900 net acres, interests in five wells and an overriding royalty interest in wells drilled prior to our sale, wells drilled subsequent to our sale and wells that might be drilled in the future.

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Aggregate net production from the Bakken formation during the three months ended June 30, 2011 was approximately 6,185 BOE, or 68 BOE per day. During July 2011, average daily net production in Bakken was approximately 55 BOE.

Grizzly. During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oil Sands ULC, or Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford Capital LP, or Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly had approximately 712,000 acres under lease and our net investment in Grizzly was $42.1 million at June 30, 2011. In addition, we had loaned Grizzly $23,895,000 including interest and net of foreign currency adjustments, as of June 30, 2011. To date, Grizzly had drilled an aggregate of 203 core holes and three water supply test wells, tested nine separate lease blocks and conducted a seismic program. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day oil sand project at Algar Lake. Grizzly expects regulatory approval in the third quarter of 2011 and construction on the first phase of the facility is expected to begin in the fourth quarter of 2011. The engineering and procurement contract for Grizzly s proposed steam assisted gravity drainage facility at Algar Lake has been awarded to SNC-Lavin. Grizzly recently completed its 2010/2011 drilling activity and shot 17 miles of 2-D seismic. Grizzly currently received an updated reserve and resource report in June 2011 integrating the results of its 2010/2011 winter exploration program.

Thailand. We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering two million acres which includes the Phu Horm Field. As of June 30, 2011, our net investment in Tatex was $1.6 million. Our investment is accounted for on the equity method. Tatex accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm s initial gross production was approximately 60 million cubic feet, or MMcf, per day. Gross production during the second quarter of 2011 was approximately 106 MMcf and 474 Bbls of oil per day. Hess Corporation operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTTEP (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex as a member of APICO) in the Phu Horm field is 0.7%. Since our ownership in the Phu Horm field is indirect and Tatex s investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

We also own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Affiliates of Wexford own approximately 17% of our outstanding common stock. Tatex III owns a concession covering one million acres. Tatex III recently completed a 3-D seismic survey on this concession. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. Drilling of the second well concluded in March 2011. The second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. Tatex III attempted to test the well but encountered a debris blockage in the open-hole portion of the wellbore that prevented the completion of the testing. Tatex III conducted a coil tubing operation to remove compacted debris blockage but was not successful. A drilling rig is on site and Tatex III expects to commence operations to remove the debris and test the well in September 2011. During the six months ended June 30, 2011, we paid $1,968,000 in cash calls bringing our total investment in Tatex III to $6.5 million.

Critical Accounting Policies and Estimates

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

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Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. 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 the 12-month unweighted average of the first-day-of-the-month price for the period 2010 and 2009, and prior to 2009, 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, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. 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 $59.7 million at June 30, 2011 and $16.8 million at December 31, 2010. These costs are reviewed quarterly 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 the 12-month unweighted average of the first-day-of-the-month price for the period January December of the applicable year beginning with 2009, and prior to 2009, 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, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids decline, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations. No ceiling test impairment was required for the quarter ended June 30, 2011.

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

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

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

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Pinnacle Energy Services, LLC and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2010 on a well-by-well basis for our properties.

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

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

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

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (a) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (b) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At June 30, 2011, a valuation allowance of $54.4 million had been provided for deferred tax assets based on the uncertainty of future taxable income.

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

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

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

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value

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are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings. We currently have fixed price swaps in place for the remainder of 2011 that are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended June 30, 2011 and 2010

We reported net income of $27,265,000 for the three months ended June 30, 2011, as compared to $10,389,000 for the three months ended June 30, 2010. This 162% increase in period-to-period net income was due primarily to a 21% increase in net production to 567,000 BOE and a 57% increase in realized BOE prices to $97.77 for the three months ended June 30, 2011 from $62.10 for the same period in 2010, partially offset by an 18% increase in lease operating expenses, a 40% increase in general and administrative expenses and a 90% increase in production taxes.

Oil and Gas Revenues. For the three months ended June 30, 2011, we reported oil and natural gas revenues of $55,462,000 as compared to oil and natural gas revenues of $29,042,000 during the same period in 2010. This $26,420,000, or 91%, increase in revenues is primarily attributable to a 21% increase in net production to 567,000 BOE from 468,000 BOE and a 57% increase in realized BOE prices to $97.77 from $62.10 for the quarter ended June 30, 2011 as compared to the quarter ended June 30, 2010.

The following table summarizes our oil and natural gas production and related pricing for the three months ended June 30, 2011, as compared to such data for the three months ended June 30, 2010:

	Three Months Ended June 30,	
	2011	2010
Oil production volumes (MBbls)	493	402
Gas production volumes (MMcf)	331	297
Liquid production volumes (MGal)	819	677
Oil equivalents (Mboe)	567	468
Average oil price (per Bbl)	$ 107.40	$ 67.24
Average gas price (per Mcf)	$ 4.57	$ 4.43
Average liquids price (per gallon)	$ 1.26	$ 1.02
Oil equivalents (per Boe)	$ 97.77	$ 62.10

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $4,706,000 for the three months ended June 30, 2011 from $3,973,000 for the same period in 2010. This increase is mainly the result of an increase in expenses related to chemicals, contract labor, ad valorem taxes and salt water hauling and disposal.

Production Taxes. Production taxes increased to $6,732,000 for the three months ended June 30, 2011 from $3,541,000 for the same period in 2010. This increase was primarily related to a 21% increase in production and a 57% increase in the average realized BOE price received resulting in a 91% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $13,712,000 for the three months ended June 30, 2011, and consisted of $13,625,000 in depletion on oil and natural gas properties and $87,000 in depreciation of other property and equipment, as compared to total DD&A expense of $8,688,000 for the three months ended June 30, 2010. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $2,119,000 for the three months ended June 30, 2011 from $1,518,000 for the same period in 2010. This $601,000 increase was due to an increase in salaries, stock compensation expenses and benefits partially resulting from an increased number of employees and increases in legal expenses, corporate fees and franchise taxes, partially offset by an increase in administrative services reimbursements and an increase in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $164,000 for the three months ended June 30, 2011 from $151,000 for the same period in 2010.

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Interest Expense. Interest expense decreased to $285,000 for the three months ended June 30, 2011 from $613,000 for the same period in 2010 due to a decrease in the interest rate paid and a decrease in the debt outstanding under our revolving credit facility to $30.0 million as of June 30, 2011, as compared to $45.5 million outstanding as of the same date in 2010. Total weighted debt outstanding under our facility was $18.5 million for the three months ended June 30, 2011 and $47.3 million for the same period in 2010. As of June 30, 2011, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 2.44%.

Income Taxes. As of June 30, 2011, we had a net operating loss carry forward of approximately $52.4 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 June 30, 2011, a valuation allowance of $54.4 million had been provided for deferred tax assets, with the exception of $628,000 related to alternative minimum taxes. We paid $1,000 in state taxes for the three months ended June 30, 2011.

Comparison of the Six Months Ended June 30, 2011 and 2010

We reported net income of $48,439,000 for the six months ended June 30, 2011, as compared to $20,370,000 for the six months ended June 30, 2010. This 138% increase in period-to-period net income was due primarily to a 19% increase in net production to 1,081,000 BOE and a 53% increase in realized BOE prices to $94.36 for the six months ended June 30, 2011 from $61.84 for the same period in 2010, partially offset by a 15% increase in lease operating expenses, a 44% increase in general and administrative expenses and an 82% increase in production taxes.

Oil and Gas Revenues. For the six months ended June 30, 2011, we reported oil and natural gas revenues of $102,037,000 as compared to oil and natural gas revenues of $56,388,000 during the same period in 2010. This $45,649,000, or 81%, increase in revenues is primarily attributable to a 19% increase in net production to 1,081,000 BOE from 912,000 BOE and a 53% increase in realized BOE prices to $94.36 from $61.84 for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010.

The following table summarizes our oil and natural gas production and related pricing for the six months ended June 30, 2011, as compared to such data for the six months ended June 30, 2010:

	Six Months Ended June 30,	
	2011	2010
Oil production volumes (MBbls)	965	818
Gas production volumes (MMcf)	495	381
Liquid production volumes (MGal)	1,428	1,285
Oil equivalents (Mboe)	1,081	912
Average oil price (per Bbl)	$ 101.69	$ 65.18
Average gas price (per Mcf)	$ 4.51	$ 4.60
Average liquids price (per gallon)	$ 1.19	$ 1.04
Oil equivalents (per Boe)	$ 94.36	$ 61.84

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $9,359,000 for the six months ended June 30, 2011 from $8,149,000 for the same period in 2010. This increase is mainly the result of an increase in expenses related to chemicals, contract labor, ad valorem taxes and salt water hauling and disposal, rentals, repairs and maintenance and field supervision.

Production Taxes. Production taxes increased to $12,239,000 for the six months ended June 30, 2011 from $6,733,000 for the same period in 2010. This increase was primarily related to a 19% increase in production and a 53% increase in the average realized BOE price received resulting in an 81% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $25,870,000 for the six months ended June 30, 2011, and consisted of $25,699,000 in depletion on oil and natural gas properties and $171,000 in depreciation of other property and equipment, as compared to total DD&A expense of $16,613,000 for the six months ended June 30, 2010. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production used to calculate our total DD&A expense.

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General and Administrative Expenses. Net general and administrative expenses increased to $4,175,000 for the six months ended June 30, 2011 from $2,900,000 for the same period in 2010. This $1,275,000 increase was due to an increase in salaries, stock compensation expenses and benefits partially resulting from an increased number of employees and increases in legal expenses, corporate fees and franchise taxes, partially offset by an increase in administrative services reimbursements and an increase in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $323,000 for the six months ended June 30, 2011 from $305,000 for the same period in 2010.

Interest Expense. Interest expense decreased to $938,000 for the six months ended June 30, 2011 from $1,331,000 for the same period in 2010 due to a decrease in the interest rate paid and a decrease in the debt outstanding under our revolving credit facility to $30.0 million as of June 30, 2011, as compared to $45.5 million outstanding as of the same date in 2010. Total weighted debt outstanding under our facility was $35.8 million for the six months ended June 30, 2011 and $48.1 million for the same period in 2010. As of June 30, 2011, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 2.44%.

Income Taxes. As of June 30, 2011, we had a net operating loss carry forward of approximately $52.4 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 June 30, 2011, a valuation allowance of $54.4 million had been provided for deferred tax assets, with the exception of $628,000 related to alternative minimum taxes. We paid $1,000 in state taxes for the six months ended June 30, 2011.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our bank and other credit facilities and the issuance of equity securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and natural gas production. During 2010, we received net proceeds (before offering expenses) of approximately $21.6 million from the sale of our common stock. In the first quarter of 2011, we received net proceeds (before offering expenses) of approximately $84.3 million from the sale of our common stock. In July 2011, we received net proceeds (before offering expenses) of approximately $94.7 million from the sale of our common stock.

Net cash flow provided by operating activities was $65,401,000 for the six months ended June 30, 2011 as compared to net cash flow provided by operating activities of $34,635,000 for the same period in 2010. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 53% increase in net realized prices and a 19% increase in our net BOE production.

Net cash used in investing activities for the six months ended June 30, 2011 was $127,427,000 as compared to $51,243,000 for the same period in 2010. During the six months ended June 30, 2011, we spent $108,368,000 in additions to oil and natural gas properties, of which $23,318,000 was spent on our 2011 drilling and recompletion programs, $30,533,000 was spent on expenses attributable to the wells drilled and recompleted during 2010, $3,632,000 was spent on compressors and other facility enhancements, $103,000 was spent on plugging costs, $41,788,000 was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and $947,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $3,181,000 was loaned and $15,539,000 was invested in Grizzly during the six months ended June 30, 2011. During the six months ended June 30, 2011, we used cash from operations and proceeds from our equity offering for our investing activities.

Net cash provided by financing activities for the six months ended June 30, 2011 was $64,236,000 as compared to $17,188,000 for the same period in 2010. The 2011 amount provided by financing activities is primarily attributable to the net proceeds of $84,425,000 from our equity offering and exercise of stock options, partially offset by net principal payments of $19,500,000 on borrowings under our credit facilities. The 2010 amount provided by financing activities is primarily attributable to the net proceeds from our equity offerings of $21,613,000.

Credit Facility. On September 30, 2010, we entered into a $100.0 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, or Amegy Bank, which revolving credit facility initially matured on September 30, 2013 and had a borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. As of June 30, 2011, $30.0 million was outstanding under the revolving credit facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheets. Subsequent to June 30, 2011, we repaid all outstanding borrowings with a portion of the net proceeds of our equity offering completed on July 15, 2011 pending the application of such proceeds to fund our additional Utica Shale lease acquisitions and for general corporate purposes. Our revolving credit agreement is secured by substantially all of our assets. Our wholly-owned subsidiaries guaranteed our obligations under the credit agreement.

On May 3, 2011, we entered into a first amendment to the revolving credit agreement with the Bank of Nova Scotia, Amegy Bank, Key Bank National Association, or Key Bank, and Société Générale. Pursuant to the terms of the first amendment, Key Bank and Société Générale were added as additional lenders, the maximum amount of the revolving credit facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by us under the credit agreement were decreased, and the maturity date was extended until May 3, 2015.

Advances under our revolving credit agreement, as amended, may be in the form of either base rate loans or Eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.00% to 1.75%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.00% to 2.75%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At June 30, 2011, amounts borrowed under our revolving credit agreement bore interest at the Eurodollar rate (2.44%).

Our revolving credit agreement contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with all covenants at June 30, 2011.

Building Loans. In June 2004, we purchased the office building we occupy in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while a second loan was scheduled to mature in June 2011. We entered into a new building loan in March 2011 to refinance the $2.4 million outstanding at that time. The new agreement extends the maturity date of the building loan to February 2016 and reduces the interest rate from 6.5% per annum to 5.82% per annum. The new building loan requires monthly interest and principal payments of approximately $22,000 and is collateralized by the Oklahoma City office building and associated land. As of June 30, 2011, approximately $2.4 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, to fund Grizzly s delineation drilling program and for acquisitions, primarily in the Permian Basin, the Niobrara Formation and Utica Shale. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, and (2) explore acquisition and disposition opportunities. We have upgraded our infrastructure and our existing facilities in Southern Louisiana with the goal of increasing operating efficiencies and volume capacities and lowering lease operating expenses. These upgrades were also intended to better enable our facilities to withstand future hurricanes with less damage. Additionally, we completed the

reprocessing of 3-D seismic data in one of our principal properties, WCBB, and shot 3-D seismic for the first time in our Hackberry field. The new and reprocessed data enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the fields, thus creating a portfolio of new drilling opportunities.

Of our net reserves at December 31, 2010, 63% were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

Our booked inventory of prospects includes approximately 29 drilling locations at WCBB. The drilling schedule used in our December 31, 2010 reserve report anticipates that all of those wells will be drilled by 2013. From January 1, 2011 through July 31, 2011, we recompleted 39 wells. We also drilled 12 wells, of which nine were completed as producers, one was non-productive, one was waiting on completion and one was being drilled. We currently intend to recomplete an additional 21 wells and drill an additional eight to twelve new wells during 2011. Our aggregate drilling and recompletion expenditures are currently estimated to be approximately $36.0 million to $38.0 million to drill 20 to 24 wells and recomplete approximately 60 existing wells in our WCBB field during 2011.

In our East Hackberry field, from January 1, 2011 through July 31, 2011, we recompleted 15 existing wells. We also drilled 12 wells, of which seven were completed as producers, two were non-productive, one was waiting on completion and two wells were drilling. We may drill three to five additional wells during 2011. Total capital expenditures for our East Hackberry field during 2011 are estimated at $24.0 million to $26.0 million to drill 15 to 17 wells and recomplete 15 wells during 2011.

In the Permian Basin, our booked inventory of prospects includes 226 gross (113 net) future development drilling locations. From January 1, 2011 through July 31, 2011, 23 gross (10.3 net) wells were drilled on this acreage, of which 11 were completed as producers, eight were waiting on completion and four wells were being drilled. We currently anticipate drilling 14 to 19 additional gross (7 to 9.5 net) wells during 2011. We currently anticipate that our capital requirements to drill 37 to 42 gross (18.5 to 21 net) wells in the Permian Basin in West Texas will be approximately $37.0 million to $39.0 million, including recompletion activity. We expected to recomplete five gross (2.5 net) wells in 2011 in the Permian Basin. To date, we have recompleted seven gross (3.5 net) wells in the Permian Basin. To help facilitate the drilling of these and future wells, we have agreed to acquire a 25% equity interest in Bison Drilling LLC, or Bison, from Windsor Energy Group LLC, or Windsor. Windsor is the operator of our Permian properties and an entity controlled by Wexford. Bison owns and operates four drilling rigs. Our purchase price for this interest is approximately $6.0 million. The remaining 75% equity interest is owned by entities controlled by Wexford.

In the Niobrara formation in Western Colorado, we are in the process of permitting a 60 square mile 3-D seismic survey and expect to begin shooting in the third quarter of 2011. Data acquisition on this survey is expected to be completed by early October 2011. We have contracted a rig and expect to begin drilling a series of at least three wells in the Niobrara by September 2011. We currently anticipate that our total capital expenditures in the Niobrara formation will be approximately $4.0 million in 2011 relating to the seismic survey and drilling of three to four gross wells.

During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. As of June 30, 2011, our net investment in Grizzly was approximately $42.1 million. In addition, we have loaned Grizzly $23.9 million including interest and net of foreign currency adjustments as of June 30, 2011. Our capital requirements in 2011 for this project are estimated to be approximately $26.0 million, primarily for the expenses associated with the initial preparations of the Algar Lake facility and drilling activity during the 2010-2011 winter drilling season.

Capital expenditures in 2011 relating to our interests in Thailand are expected to be approximately $2.0 million, which we believe will be mostly funded from our share of production from the Phu Horm field.

Our total capital expenditures for 2011 are currently estimated to be in the range of $127.0 million to $133.0 million, excluding the cost of our Utica Shale and any other potential acquisitions. This is up significantly from the $85.8 million spent in 2010 due to improved commodity pricing and cost environment. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

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

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Commodity Price Risk

For the period January 2010 through February 2010, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we entered into forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period from January 2011 through December 2011. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contacts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we could access the trust for use in plugging and abandonment charges associated with the property, although we have not yet done so. As of June 30, 2011, the plugging and abandonment trust totaled approximately $3,121,000. At June 30, 2011, we had plugged 311 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

New Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, *Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosure* , or FASB ASC 820. The purpose of the amendments in this update is to create common fair value measurement and disclosure requirements between GAAP and IFRS. The amendments change certain fair value measurement principles and enhance the disclosure requirements. The amendments to FASB ASC 820 are effective for interim and annual periods beginning after December 15, 2011.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income: Presentation of Comprehensive Income,* which provides amendments to FASB ASC Topic 220, *Comprehensive Income* , or FASB ASC 220. The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in stockholders equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. The amendments to FASB ASC 220 are effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively.

ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment. These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per

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MMBtu in January 2006. On June 30, 2011, the West Texas Intermediate posted price for crude oil was $95.42 per bbl and the Henry Hub spot market price of natural gas was $4.37 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.

For the period January 2010 through February 2010, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we entered into forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period from January 2011 through December 2011. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

At June 30, 2011, we had a net liability derivative position of $3.4 million related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $3.5 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by $3.5 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or Eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the Eurodollar rates are elected, the Eurodollar rates. At June 30, 2011, amounts borrowed under our revolving credit agreement bore interest at the Eurodollar rate of 2.44%. Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $300,000 per year, based on $30.0 million outstanding under our credit facility as of June 30, 2011. As of June 30, 2011, we had $30.0 million outstanding under our revolving credit facility. As of June 30, 2011, we did not have any interest rate swaps to hedge our interest risks.

ITEM 4. CONTROLS AND PROCEDURES

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

As of June 30, 2011, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of June 30, 2011, our disclosure controls and procedures are effective.

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay

had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against our company seeking $2,275,729 in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes and are defending our company in the lawsuit. The case is in the early stages of discovery. The LDR has taken no further action on this lawsuit since filing its petition over two years ago.

In December 2010, the LDR filed two identical lawsuits against us in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney s fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by the LDR in 2009, we have denied all liability and will vigorously defend the lawsuit. The cases are in the very early stages, and we have not yet filed a response to these lawsuits. Recently, the LDR filed motions to stay the lawsuits before we filed any responsive pleadings. The LDR has advised us that it intends to pursue settlement discussions with us and other similarly situated defendants in separate proceedings.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us, Great White Pressure Control LLC, or Great White, and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. We filed a motion for summary judgment on October 5, 2007. The Court entered a final interlocutory judgment in favor of all defendants, including us, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that we conspired with the other defendants to misappropriate, and misappropriated Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, our motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages. In 2011, the parties have continued with written discovery and production of documents. On February 15, 2011, Cudd filed a third amended petition seeking $26.5 million (based on a report prepared by its expert) plus disgorgement of $6.0 million in payments by Great White to the individual defendants and punitive damages. Gulfport denies these claims with respect to itself. Recently, the parties began the process of scheduling depositions and it is anticipated that the case will remain in the discovery phase for months to come.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled *Reeds et al. v. BP American Production Company et al.,* 38th Judicial District. No. 10-18714. The plaintiffs original petition for damages, which did not name us as a defendant, alleges that the plaintiffs property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants, which in addition to BP America Production Company include ExxonMobil Corporation, Shell Oil Company, ConocoPhillips Company, Sun Oil Company and Schlumberger Technology Corporation, conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, we were served with a copy of the plaintiffs first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including us, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses; and damages for evaluation and remediation of any contamination that threatens groundwater. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by us and other defendants, the plaintiffs filed a third amending petition with exhibits which expand the description of the property at issue, attach numerous aerial photos, and identify the mineral leases at issue. In response, we and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. These pleadings were heard on May 25, 2011, and the defendants legal arguments were denied. As of July 27, 2011, the court had not entered a judgment regarding its ruling. Once it does, the defendants will have 30 days to file a supervisory writ with the appellate court seeking to overturn the lower court s ruling.

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

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

ITEM 1A. RISK FACTORS.

Other than as set forth below, there have been no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as Class II UIC wells. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. As part of these studies, both the EPA and the House committee have requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. In addition, it has been reported that the Securities and Exchange Commission is investigating the accuracy of claims made by certain shale producers regarding their production volumes.

In March 2011, companion bills entitled the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act of 2009 were reintroduced in the United States Senate and House of Representatives. These bills, which are currently under consideration by Congress, would repeal the exemption for hydraulic fracturing from the SWDA, which would have the effect of allowing the EPA to promulgate regulations requiring permits and implementing potential new requirements on hydraulic fracturing under the SWDA. This could, in turn, require state regulatory agencies in states with programs delegated under the SWDA to impose additional requirements on hydraulic fracturing operations. In addition, the bills would require persons using hydraulic fracturing, such as us, to disclose the chemical constituents, but not the proprietary formulas, of their fracturing fluids to a regulatory agency, which would make the information public via the internet. Additionally, fracturing companies would be required to disclose specific chemical contents of fluids, including proprietary chemical formulas, to state authorities or to a requesting physician or nurse if deemed necessary by the physician or nurse in connection with a medical emergency.

Some states have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, in June 2010, the Wyoming Oil and Gas Conservation Commission passed a rule requiring disclosure of hydraulic fracturing fluid content. In November 2010, the Pennsylvania Environmental Quality Board proposed regulations that would require reporting of the chemicals used in fracturing fluids. Effective January 15, 2011, Arkansas began requiring disclosure of the components, but not the precise chemical composition, of hydraulic fracturing fluids. On May 31, 2011, the Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. It was signed into law on June 17, 2011, effective as of September 1, 2011. The Texas Railroad Commission will adopt rules and regulations implementing this legislation in two phases by July 1, 2012 and 2013, respectively. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. In addition, the new law requires disclosure on a public website and to the Texas Railroad Commission of other chemical ingredients that were intentionally included and used for the purpose of hydraulic fracturing. The new law contemplates that certain hydraulic fracturing chemicals may be claimed as a trade secret, although disclosure of such information would be required to a health professional or emergency responder who needs the information for medical treatment.

If new laws or regulations that significantly restrict hydraulic fracturing, such as the FRAC Act, are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We acquire significant amounts of unproved property in order to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. Drilling results in our newer oil and liquids-rich shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in new shale formations.

We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

Approximately 65% of our proved reserves at December 31, 2010 are attributable to our acreage position in the Permian Basin. We are not the operator of these properties and may have limited ability to exercise influence over the operations of these and our other non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs, could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator s expertise and financial resources;
- approval of other participants in drilling wells;

selection of technology; and

the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

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

(a) None

(b) Not Applicable.

(c) We do not have a share repurchase program, and during the three months ended June 30, 2011, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. REMOVED AND RESERVED

ITEM 5. OTHER INFORMATION

(a) On August 5, 2011, the nominating committee of our board of directors recommended, and our board of directors approved, an increase in the size of our board of directors from five directors to six directors. Based on the recommendation of the nominating committee, on August 5, 2011, our board of directors appointed Craig Groeschel to fill the newly created directorship. Our board of directors has determined that Mr. Groeschel qualifies as an independent director for purposes of serving on our board of directors under the Nasdaq listing rules. Since 1996, Mr. Groeschel has served as a founding pastor of LifeChurch.tv, one of the largest churches in the United States, reaching over 30,000 people each weekend. Since founding LifeChurch, Mr. Groeschel has served on its Board of Directors. Under Mr. Groeschel s leadership, LifeChurch has grown to 15 locations in the United States. Mr. Groeschel received a Bachelors in Business Marketing from the Oklahoma City University and a Masters of Divinity from the Phillips Graduate Seminary. Mr. Groeschel is a frequent speaker at various domestic and international forums and an author of a number of books.

For his service on our board of directors, Mr. Groeschel will be entitled to receive cash compensation provided to our other non-employee directors, as described in more detail in our most recent Proxy Statement on Schedule 14A filed with the SEC. From time to time, we also provide our non-employee directors with equity compensation under our Amended and Restated 2005 Stock Incentive Plan as additional compensation and incentive.

(b) None.

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
10.1	Credit Agreement, dated as of June 30, 2011, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
10.2	First Amendment, dated May 3, 2011, of Credit Agreement, dated September 30, 2011, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent and letter of credit issuer, Amegy Bank National Association, Key Bank National Association and Société Générale (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 000-19514 filed by the Company with the SEC on May 9, 2011).
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.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.
** Furnished herewith, not filed.

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SIGNATURES

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

GULFPORT ENERGY CORPORATION

Date: August 5, 2011

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

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

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