GULFPORT ENERGY CORP
Form 10-Q
August 09, 2012

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

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2012
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 (State or Other Jurisdiction of Incorporation or Organization)	73-1521290 (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 ý 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 ý 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	x	Accelerated Filer	¨
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 ý

As of August 1, 2012, 55,687,845 shares of common stock were outstanding.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$6,613,000	$93,897,000
Accounts receivable - oil and gas	23,269,000	28,019,000
Accounts receivable - related parties	27,182,000	4,731,000
Prepaid expenses and other current assets	3,136,000	1,327,000
Short-term derivative instruments	9,714,000	1,601,000
Total current assets	69,914,000	129,575,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $199,598,000 and $138,623,000 excluded from amortization in 2012 and 2011, respectively	1,219,376,000	1,035,754,000
Other property and equipment	8,387,000	8,024,000
Accumulated depletion, depreciation, amortization and impairment	(620,182,000)	(575,142,000)
Property and equipment, net	607,581,000	468,636,000
Other assets		
Equity investments	185,934,000	86,824,000
Note receivable - related party	1,595,000	—
Other assets	5,776,000	5,123,000
Total other assets	193,305,000	91,947,000
Deferred tax asset	1,000,000	1,000,000
Total assets	$871,800,000	$691,158,000
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$95,689,000	$43,872,000
Asset retirement obligation - current	60,000	620,000
Current maturities of long-term debt	145,000	141,000
Total current liabilities	95,894,000	44,633,000
Asset retirement obligation - long-term	13,120,000	12,033,000
Long-term debt, net of current maturities	70,072,000	2,142,000
Total liabilities	179,086,000	58,808,000
Commitments and contingencies (Note 10)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—	—
Stockholders’ equity:		
Common stock - $.01 par value, 100,000,000 authorized, 55,687,845 issued and outstanding in 2012 and 55,621,371 in 2011	557,000	556,000
Paid-in capital	606,853,000	604,584,000
Accumulated other comprehensive income (loss)	8,771,000	2,663,000
Retained earnings	76,533,000	24,547,000
Total stockholders’ equity	692,714,000	632,350,000
Total liabilities and stockholders’ equity	$871,800,000	$691,158,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues:				
Oil and condensate sales	$65,020,000	$52,916,000	$129,024,000	$98,112,000
Gas sales	541,000	1,512,000	1,154,000	2,232,000
Natural gas liquids sales	694,000	1,034,000	1,500,000	1,693,000
Other income	70,000	127,000	108,000	190,000
	66,325,000	55,589,000	131,786,000	102,227,000
Costs and expenses:				
Lease operating expenses	5,714,000	4,706,000	11,563,000	9,359,000
Production taxes	7,572,000	6,732,000	15,341,000	12,239,000
Depreciation, depletion, and amortization	23,652,000	13,712,000	45,047,000	25,870,000
General and administrative	3,263,000	2,119,000	6,272,000	4,175,000
Accretion expense	177,000	164,000	353,000	323,000
	40,378,000	27,433,000	78,576,000	51,966,000
INCOME FROM OPERATIONS:	25,947,000	28,156,000	53,210,000	50,261,000
OTHER (INCOME) EXPENSE:				
Interest expense	474,000	285,000	627,000	938,000
Interest income	(4,000)	(37,000)	(31,000)	(75,000)
Loss from equity method investments	360,000	642,000	628,000	958,000
	830,000	890,000	1,224,000	1,821,000
INCOME BEFORE INCOME TAXES	25,117,000	27,266,000	51,986,000	48,440,000
INCOME TAX EXPENSE:	—	1,000	—	1,000
NET INCOME	$25,117,000	$27,265,000	$51,986,000	$48,439,000
NET INCOME PER COMMON SHARE:				
Basic	$0.45	$0.57	$0.93	$1.05
Diluted	$0.45	$0.57	$0.93	$1.04
Weighted average common shares outstanding - Basic	55,656,274	47,454,359	55,641,241	46,097,207
Weighted average common shares outstanding - Diluted	56,334,095	47,898,665	56,175,248	46,548,414

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income	$25,117,000	$27,265,000	$51,986,000	$48,439,000
Foreign currency translation adjustment	(2,865,000)	401,000	(1,926,000)	1,570,000
Change in fair value of derivative instruments	18,194,000	6,780,000	7,573,000	(722,000)
Reclassification of settled contracts	561,000	1,164,000	461,000	2,011,000
Other comprehensive income	15,890,000	8,345,000	6,108,000	2,859,000
Comprehensive income	$41,007,000	$35,610,000	$58,094,000	$51,298,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount				
Balance at January 1, 2012	55,621,371	$556,000	$604,584,000	$ 2,663,000	$24,547,000	$632,350,000
Net income	—	—	—	—	51,986,000	51,986,000
Other Comprehensive Loss	—	—	—	6,108,000	—	6,108,000
Stock Compensation	—	—	2,270,000	—	—	2,270,000
Issuance of Restricted Stock	66,474	1,000	(1,000)	—	—	—
Balance at June 30, 2012	55,687,845	$557,000	$606,853,000	$ 8,771,000	$76,533,000	$692,714,000
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 Loss	—	—	—	2,859,000	—	2,859,000
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

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30, 2012	2011
Cash flows from operating activities:		
Net income	$51,986,000	$48,439,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount - Asset Retirement Obligation	353,000	323,000
Depletion, depreciation and amortization	45,047,000	25,870,000
Stock-based compensation expense	1,362,000	272,000
Loss from equity investments	628,000	958,000
Interest income - note receivable	(1,000)	(76,000)
Unrealized gain on derivative instruments	(79,000)	—
Amortization of loan commitment fees	252,000	241,000
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable	4,750,000	(4,920,000)
Increase in accounts receivable - related party	(22,451,000)	(8,985,000)
Increase in prepaid expenses	(1,809,000)	(191,000)
Increase in accounts payable and accrued liabilities	20,461,000	3,470,000
Settlement of asset retirement obligation	(1,002,000)	—
Net cash provided by operating activities	99,497,000	65,401,000
Cash flows from investing activities:		
Deductions to cash held in escrow	8,000	8,000
Additions to other property, plant and equipment	(503,000)	(92,000)
Additions to oil and gas properties	(150,653,000)	(108,368,000)
Proceeds from sale of other property, plant and equipment	140,000	—
Proceeds from sale of oil and gas properties	—	1,384,000
Advances on note receivable to related party	(1,594,000)	(3,181,000)
Contributions to equity method investments	(101,864,000)	(17,507,000)
Distributions from equity method investments	200,000	329,000
Net cash used in investing activities	(254,266,000)	(127,427,000)
Cash flows from financing activities:		
Principal payments on borrowings	(12,066,000)	(54,565,000)
Borrowings on line of credit	80,000,000	35,000,000
Loan commitment fees	(449,000)	(624,000)
Proceeds from issuance of common stock, net of offering costs, and exercise of stock options	—	84,425,000
Net cash provided by financing activities	67,485,000	64,236,000
Net (decrease) increase in cash and cash equivalents	(87,284,000)	2,210,000
Cash and cash equivalents at beginning of period	93,897,000	2,468,000
Cash and cash equivalents at end of period	$6,613,000	$4,678,000

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GULFPORT ENERGY CORPORATION
Consolidated Statements of Cash Flows, Continued
(Unaudited)

Supplemental disclosure of cash flow information:		
Interest payments	$237,000	$778,000
Income tax payments	$255,000	$—
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$908,000	$181,000
Asset retirement obligation capitalized	$1,176,000	$449,000
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$(1,926,000)	$938,000
Foreign currency translation gain (loss) on note receivable - related party	$—	$632,000

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, 2012 are not necessarily indicative of the results expected for the full year.

1. ACQUISITIONS

Beginning in February 2011, the Company entered into agreements to acquire certain leasehold interests located in the Utica Shale in Ohio. Certain of the agreements also granted the Company an exclusive right of first refusal for a period of six months on certain additional tracts leased by the seller. Gulfport is the operator on this acreage in the Utica Shale. As of June 30, 2012, the Company had acquired leasehold interests in approximately 116,000 gross (58,000 net) acres in the Utica Shale for approximately $169.8 million. Gulfport funded these transactions with a portion of the proceeds from public offerings of an aggregate of 6.2 million shares of the Company’s common stock completed in March and July of 2011. The Company also has commitments with various future closing dates that could increase its acreage position in the Utica Shale to an aggregate of approximately 125,000 gross (62,500 net) leasehold acres. Entities controlled by Wexford Capital LP (“Wexford”) have participated with the Company on a 50/50 basis in the acquisition of all leases described above.

2. ACCOUNTS RECEIVABLE – RELATED PARTY

Included in the accompanying June 30, 2012 and December 31, 2011 consolidated balance sheets are amounts receivable from related parties of the Company. These receivables consist primarily of amounts billed by the Company to related parties as operator of such parties' Colorado and Ohio oil and gas properties. At June 30, 2012 and December 31, 2011, these receivables totaled $27,182,000 and $4,731,000, respectively.

The Company is a party to administrative service agreements with Stampede Farms LLC (“Stampede”), Everest Operations Management LLC (“Everest”) and Tatex Thailand III, LLC (“Tatex III”), which agreements were each entered into effective March 1, 2008. Under these agreements, the Company’s services include professional and technical support and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements may be cancelled (1) by the Company with at least 60 days prior written notice, (2) by the counterparty at any time with at least 30 days prior written notice to the Company and (3) 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 did not provide services under any of these agreements in 2011 and received no reimbursements thereunder. Each of Stampede, Everest and Tatex III is controlled by Wexford. Charles E. Davidson is the Chairman and Chief Investment Officer of Wexford and he beneficially owned approximately 13.3% and 9.5% of the Company’s outstanding common stock as of December 31, 2011 and March 13, 2012, respectively.

Effective July 1, 2008, the Company entered into an acquisition team agreement with Everest to identify and evaluate potential oil and gas properties in which the Company and Everest or its affiliates 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. Affiliates of Everest were billed approximately $208,000 and $533,000 under this acquisition team agreement during the three months and six months ended June 30, 2012, respectively, and $401,000 and $401,000 during the three months and six months ended June 30, 2011, respectively, which amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

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 Formation. The

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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, 2012 and December 31, 2011 are as follows:

	June 30, 2012	December 31, 2011
Oil and natural gas properties	$1,219,376,000	$1,035,754,000
Office furniture and fixtures	4,201,000	3,692,000
Building	3,926,000	4,049,000
Land	260,000	283,000
Total property and equipment	1,227,763,000	1,043,778,000
Accumulated depletion, depreciation, amortization and impairment	(620,182,000)	(575,142,000)
Property and equipment, net	$607,581,000	$468,636,000

Included in oil and gas properties at June 30, 2012 is the cumulative capitalization of $27,630,000 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 $2,160,000 and $4,136,000 for the three months and six months ended June 30, 2012, respectively, and $1,411,000 and $2,788,000 for the three months and six months ended June 30, 2011, respectively.

The following table summarizes the Company's non-producing properties excluded from amortization by area at June 30, 2012:

	June 30, 2012
West Texas Permian	$15,033,000
Colorado	5,697,000
Bakken	300,000
Southern Louisiana	709,000
Ohio	172,103,000
Belize	5,711,000
Other	45,000
	$199,598,000

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

A reconciliation of the asset retirement obligation for the six months ended June 30, 2012 and 2011 is as follows:

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	June 30, 2012	June 30, 2011
Asset retirement obligation, beginning of period	$12,653,000	$10,845,000
Liabilities incurred	1,176,000	449,000
Liabilities settled	(1,002,000)	—
Accretion expense	353,000	323,000
Asset retirement obligation as of end of period	13,180,000	11,617,000
Less current portion	60,000	635,000
Asset retirement obligation, long-term	$13,120,000	$10,982,000

On May 7, 2012, the Company entered into a contribution agreement with Diamondback Energy, Inc., (“Diamondback”). Under the terms of the contribution agreement, the Company agreed to contribute to Diamondback, prior to the closing of the Diamondback initial public offering (“Diamondback IPO”), all its oil and gas interests in the Permian Basin in exchange for (i) shares of common stock representing 35% of Diamondback’s outstanding common stock immediately prior to the closing of the Diamondback IPO and (ii) $63,590,050.00 in the form of a non-interest bearing promissory note, which will be repaid in full upon the closing of the Diamondback IPO with a portion of the net proceeds from that offering. The aggregate consideration payable to the Company is subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and other items of Windsor Permian LLC (“Windsor Permian”) referred to in the contribution agreement as of the date of the contribution. Windsor Permian, an entity controlled by Wexford, is the operator of the Company’s acreage to be contributed and will be a wholly-owned subsidiary of Diamondback at the time of the contribution. The Company’s obligation to make this contribution is contingent upon, among other things, the contribution to Diamondback of all the outstanding equity interests in Windsor Permian, the Company’s satisfaction with the terms of the Diamondback IPO and customary closing conditions. Under the contribution agreement, the Company is generally responsible for all liabilities and obligations with respect to the contributed properties arising prior to the contribution and Diamondback is responsible for such liabilities and obligations with respect to the contributed properties arising after the contribution.

In connection with the contribution, the Company and Diamondback will enter into an investor rights agreement in which the Company will have the right, for so long as it beneficially owns more than 10% of Diamondback’s outstanding common stock, to designate one individual as a nominee to serve on Diamondback’s board of directors. Such nominee, if elected to Diamondback’s board, will also serve on each committee of the board so long as he or she satisfies the independence and other requirements for service on the applicable committee of the board. So long as the Company has the right to designate a nominee to Diamondback’s board and there is no Gulfport nominee actually serving as a Diamondback director, the Company will have the right to appoint one individual as an advisor to the board who shall be entitled to attend board and committee meetings. The Company will also be entitled to certain information rights and Diamondback will grant the Company certain demand and “piggyback” registration rights obligating Diamondback to register with the SEC any shares of Diamondback common stock that the Company owns. If the contribution is completed, the Company will own a 35% equity interest in Diamondback immediately prior to the closing of the Diamondback IPO, rather than leasehold interests in the Company’s Permian Basin acreage. In the event the contribution is completed, the investment in Diamondback will be accounted for as an equity method investment going forward.

4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of June 30, 2012 and December 31, 2011:

	June 30, 2012	December 31, 2011
Investment in Tatex Thailand II, LLC	$829,000	$1,030,000
Investment in Tatex Thailand III, LLC	8,840,000	8,282,000
Investment in Grizzly Oil Sands ULC	144,810,000	69,008,000
Investment in Bison Drilling and Field Services LLC	14,228,000	6,366,000
Investment in Muskie Holdings LLC	4,310,000	2,138,000
Investment in Timber Wolf Terminals LLC	977,000	—
Investment in Windsor Midstream LLC	7,710,000	—
Investment in Stingray Pressure Pumping LLC	3,940,000	—
Investment in Stingray Cementing LLC	290,000	—
Investment in Blackhawk Midstream LLC	—	—
	$185,934,000	$86,824,000

Tatex Thailand II, LLC

The Company has a 23.5% ownership interest in Tatex Thailand II, LLC ("Tatex"). The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex 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, 2012, Gulfport received $200,000 in distributions, reducing its total net investment in Tatex to $829,000. The loss on equity investment related to Tatex was immaterial for the six months ended June 30, 2012 and 2011.

Tatex Thailand III, LLC

The Company has a 17.9% ownership interest in Tatex III. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. During the six months ended June 30, 2012, Gulfport paid $626,000 in cash calls, increasing its total net investment in Tatex III to $8,840,000. The Company recognized a loss on equity investment of $68,000 and $138,000 for the six months ended June 30, 2012 and 2011, respectively, which is included in loss from equity method investments in the consolidated statements of operations.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns a 24.9999% interest in Grizzly Oil Sands ULC, a Canadian unlimited liability company ("Grizzly"). The remaining interest in Grizzly is owned by an entity controlled by Wexford. Since 2006, Grizzly has acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray and other oil sands development projects. Grizzly has drilled core holes and water supply test wells in eleven 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 a SAGD facility at Algar Lake. In November 2011, the Government of Alberta provided a formal Order-in Council authorizing the Alberta Energy Resources Conservation Board (ERCB) to issue formal regulatory approval of the project. Fabrication and onsite construction on the first phase of development at Algar Lake is currently underway. During the six months ended June 30, 2012, Gulfport paid $78,312,000 in cash calls, increasing Gulfport's net investment in Grizzly to $144,810,000. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was decreased by $2,865,000 and $1,926,000 as a result of a currency translation loss for the three months and six months ended June 30, 2012, respectively. The Company recognized a loss on equity investment of $306,000 and $584,000 for the three months and six months ended June 30, 2012, respectively, and $558,000 and $813,000 for the three months and six months ended June 30, 2011, respectively, which is included in loss from equity method investments in the consolidated statements of operations.

The Company, through Grizzly Holdings, entered into a loan agreement with Grizzly effective January 1, 2008, as amended from time-to-time, under which Grizzly borrowed funds from the Company. Interest was paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The Company recognized interest income of approximately $40,000 and $76,000 for the three months and six months ended June 30, 2011, respectively, which is included in interest income in the consolidated statements of operations. Effective December 7, 2011, Grizzly Holdings entered into a debt settlement agreement with Grizzly under which Grizzly agreed to satisfy the entire outstanding debt by issuing additional common shares of Grizzly with no effect to the composition of the ownership structure of Grizzly. At such date, the Company's investment in Grizzly

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increased by the total $22,325,000 of outstanding advances and accrued interest due from Grizzly, the cumulative $75,000 currency translation loss for the note receivable was adjusted through accumulated other comprehensive income and the note receivable was considered paid in full.

Bison Drilling and Field Services LLC

During the third quarter of 2011, the Company purchased a 25% ownership interest in Bison Drilling and Field Services LLC ("Bison") at a cost of $6,009,000, subject to adjustment. In April 2012, the Company purchased an additional 15% ownership interest in Bison for $6,152,000, bringing its total ownership interest in Bison to 40%. The remaining interests in Bison are owned by entities controlled by Wexford. Bison owns and operates drilling rigs. During the six months ended June 30, 2012, Gulfport paid $1,373,000 in cash calls, increasing its total net investment in Bison to $14,228,000. The Company recognized income on equity investment of $342,000 and $337,000 for the three months and six months ended June 30, 2012, respectively, which is included in loss from equity method investments in the consolidated statements of operations.

The Company entered into a loan agreement with Bison effective May 15, 2012, under which Bison may borrow funds from the Company. Interest accrues at LIBOR plus 0.28% or 8%, whichever is lower, and shall be paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan has a maturity date of January 31, 2015. The Company loaned Bison $1,594,000 during the six months ended June 30, 2012. The interest income recognized on the note was immaterial for the three months and six months ended June 30, 2012. The $1,595,000 balance due from Bison at June 30, 2012 is included in note receivable - related party on the accompanying consolidated balance sheets.

Muskie Holdings LLC

During the fourth quarter of 2011, the Company purchased a 25% ownership interest in Muskie Holdings LLC ("Muskie") at a cost of $2,142,000, subject to adjustment. The remaining interests in Muskie are owned by entities controlled by Wexford. Muskie holds certain assets, real estate and rights in a lease covering land in Wisconsin that is prospective for mining oil and natural gas fracture grade sand. During the six months ended June 30, 2012, Gulfport paid $2,244,000 in cash calls, increasing its total net investment in Muskie to $4,310,000. The Company recognized a loss on equity investment of $63,000 and $72,000 for the three months and six months ended June 30, 2012, respectively, which is included in loss from equity method investments in the consolidated statements of operations.

Timber Wolf Terminals LLC

During the first quarter of 2012, the Company purchased a 50% ownership interest in Timber Wolf Terminals LLC ("Timber Wolf") at a cost of $1,000,000. The remaining interests in Timber Wolf are owned by entities controlled by Wexford. Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. The Company recognized a loss on equity investment of $23,000 for the three months and six months months ended June 30, 2012, which is included in loss from equity method investments in the consolidated statements of operations.

Windsor Midstream LLC

During the first quarter of 2012, the Company purchased a 22.5% ownership interest in Windsor Midstream LLC ("Midstream") at a cost of $7,021,000. The remaining interests in Midstream are owned by entities controlled by Wexford. Midstream owns a 28.4% interest in MidMar Gas LLC, a gas processing plant in West Texas. During the six months ended June 30, 2012, the Company paid $574,000 in cash calls, increasing its total net investment in Midstream to $7,710,000. The Company recognized income on equity investment of $56,000 and $115,000 for the three months and six months ended June 30, 2012, respectively, which is included in loss from equity method investments in the consolidated statements of operations.

Stingray Pressure Pumping LLC

During the second quarter of 2012, the Company purchased a 50% ownership interest in Stingray Pressure Pumping LLC ("Stingray Pressure"). The remaining interest in Stingray Pressure is owned by an entity controlled by Wexford. Stingray Pressure provides well completion services. During the six months ended June 30, 2012, the Company paid $4,027,000 in cash calls, increasing its total net investment in Stingray Pressure to $3,940,000. The Company recognized a loss on equity investment of $87,000 for the three months and six months ended June 30, 2012, which is included in loss from equity method investments in the consolidated statements of operations.

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Stingray Cementing LLC

During the second quarter of 2012, the Company purchased a 50% ownership interest in Stingray Cementing LLC ("Stingray Cementing"). The remaining interest in Stingray Cementing is owned by an entity controlled by Wexford. Stingray Cementing provides well cementing services. During the six months ended June 30, 2012, the Company paid $291,000 in cash calls, increasing its net investment in Stingray Cementing to $290,000. The loss on equity investment related to Stingray Cementing was immaterial for the three months and six months ended June 30, 2012.

Blackhawk Midstream LLC

During the second quarter of 2012, the Company purchased a 50% ownership interest in Blackhawk Midstream LLC ("Blackhawk"). The remaining interest in Blackhawk is owned by an entity controlled by Wexford. Blackhawk provides gathering, compression, processing and marketing solutions for the Company's natural gas and natural gas liquids in the Utica Shale. During the six months ended June 30, 2012, the Company paid $244,000 in cash calls. The Company recognized a loss on equity investment of $244,000 for the three months and six months ended June 30, 2012, which is included in loss from equity method investments in the consolidated statements of operations.

5. OTHER ASSETS

Other assets consist of the following as of June 30, 2012 and December 31, 2011:

	June 30, 2012	December 31, 2011
Plugging and abandonment escrow account on the WCBB properties (Note 10)	$3,113,000	$3,121,000
Certificates of deposit securing letter of credit	275,000	275,000
Prepaid drilling costs	644,000	228,000
Loan commitment fees, net	1,740,000	1,495,000
Deposits	4,000	4,000
	$5,776,000	$5,123,000

6. LONG-TERM DEBT

A breakdown of long-term debt as of June 30, 2012 and December 31, 2011 is as follows:

	June 30, 2012	December 31, 2011
Revolving credit agreement (1)	$68,000,000	$—
Building loans (2)	2,217,000	2,283,000
Less: current maturities of long term debt	(145,000)	(141,000)
Debt reflected as long term	$70,072,000	$2,142,000

Maturities of long-term debt as of June 30, 2012 are as follows:

2013	$145,000
2014	154,000
2015	68,164,000
2016	1,754,000
2017	—

Thereafter	—
Total	$70,217,000

(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. The revolving credit facility initially matured on September 30, 2013 and had an initial borrowing base

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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 guaranteed 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. On October 31, 2011, the Company entered into additional amendments to its revolving credit facility pursuant to which, among other things, the borrowing base under this facility was increased to $125.0 million. Effective May 2, 2012, the Company entered into additional amendments to its revolving credit facility pursuant to which, among other things, the borrowing base was increased to $155.0 million and Credit Suisse, Deutsche Bank Trust Company Americas and Iberiabank were added as additional lenders and Société Générale left the bank group. As of June 30, 2012, approximately $68,000,000 was outstanding under the credit agreement.

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, 2012, amounts borrowed under the credit agreement bore interest at the eurodollar rate (2.49%).

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, 2012.

(2) In March 2011, the Company entered into a new building loan agreement for the office building it occupies in Oklahoma City, Oklahoma. The new loan agreement refinanced the $2.4 million outstanding under the previous

building loan agreement. The new agreement extended the maturity date of the building loan to February 2016 and reduced the interest rate 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. STOCK-BASED COMPENSATION

During the three months and six months ended June 30, 2012, the Company's stock-based compensation expense was $1,135,000 and $2,270,000, respectively, of which the Company capitalized $454,000 and $908,000, respectively, relating to its exploration and development efforts. 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.

Options and restricted common stock are reported as share based payments and their fair value is amortized to expense

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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, 2012 and 2011.

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, 2012 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2011	356,241	$6.51	3.41	$8,172,000
Granted	—	—		
Exercised	—	—		
Forfeited/expired	—	—		
Options outstanding at June 30, 2012	356,241	$6.51	2.91	$5,030,000
Options exercisable at June 30, 2012	356,241	$6.51	2.91	$5,030,000

The following table summarizes information about the stock options outstanding at June 30, 2012:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$3.36	206,241	2.56	206,241
$9.07	25,000	3.19	25,000
$11.20	125,000	3.42	125,000
	356,241		356,241

The following table summarizes restricted stock activity for the six months ended June 30, 2012:

	Number of Unvested Restricted	Weighted Average Grant Date Fair

	Shares	Value
Unvested shares as of December 31, 2011	203,348	$26.02
Granted	167,500	37.36
Vested	(66,474)	30.15
Forfeited	—	—
Unvested shares as of June 30, 2012	304,374	$31.36

Unrecognized compensation expense as of June 30, 2012 related to outstanding stock options and restricted shares was

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$8,808,000. The expense is expected to be recognized over a weighted average period of 1.78 years.

8. EARNINGS PER SHARE

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

	For the Three Months Ended June 30,					
	2012			2011		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$25,117,000	55,656,274	$0.45	$27,265,000	47,454,359	$0.57
Effect of dilutive securities:						
Stock options and restricted stock awards	—	677,821		—	444,306	
Diluted:						
Net income	$25,117,000	56,334,095	$0.45	$27,265,000	47,898,665	$0.57

	For the Six Months Ended June 30,					
	2012			2011		
	2012	Shares	Per Share	Income	Shares	Per Share
Basic:						
Net income	$51,986,000	55,641,241	$0.93	$48,439,000	46,097,207	$1.05
Effect of dilutive securities:						
Stock options and restricted stock awards	—	534,007		—	451,207	
Diluted:						
Net income	$51,986,000	56,175,248	$0.93	$48,439,000	46,548,414	$1.04

There were no potential shares of common stock that were considered anti-dilutive during the three months and six months ended June 30, 2012 and 2011.

9. 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. The adoption did not have a material impact on the Company’s consolidated financial statements.

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. The components of other comprehensive income and total comprehensive income are presented in the accompanying consolidated statements of comprehensive income (loss).

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10. 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, 2012, the plugging and abandonment trust totaled approximately $3,113,000. At June 30, 2012, the Company had plugged 354 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 had taken no further action on this lawsuit since filing its petition until recently when it propounded discovery requests to which Gulfport has responded. Since Gulfport served discovery requests on the LDR and received the LDR’s responses, there has been no further activity in this case and no trial date has been set.

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 the 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, but has taken no action to initiate settlement talks. There has been no activity on either of these lawsuits for more than a year.

Other Litigation

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. In 2011 and 2012, the parties engaged in extensive discovery and motion practice. On July 5, 2012, Cudd filed a fourth amended petition, which largely tracks the prior petitions but adds two additional causes of action and provides more detailed information regarding the damages Cudd is seeking. Among other things, Cudd claims the defendants, including Gulfport, owe $11.8 million as a reasonable royalty for the alleged use of its trade secrets. Cudd also seeks disorgement of the alleged benefits received by the various defendants. Cudd has not quantified the benefit it seeks to have Gulfport disgorge, but has alleged that Gulfport received from Wexford the opportunity to participate in Wexford's deals on a special no cost basis in exchange for participating in the alleged conduct. Cudd also seeks its attorney's fees, which Cudd claims is not less than $450,000, plus 10% of any final judgment. Gulfport denies all of Cudd's claims. All parties have filed motions for summary judgment which have not yet been heard by the court. The case is set to go to trial on September 5, 2012.

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 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. In addition to Gulfport, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, Gulfport filed a pleading challenging the legal sufficiency of the petitions on several grounds 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 similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, Gulfport and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. Some of the defendants' grounds for challenging the plaintiffs' petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. Gulfport noticed its intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. Gulfport filed its supervisory writ, which was recently denied by the Louisiana Third Circuit Court of Appeal. Gulfport filed a writ to the Louisiana Supreme Court on this issue, and there has not yet been a ruling. Gulfport has been active in serving discovery requests and responding to discovery requests from the plaintiffs. It is anticipated that the discovery phase of this case will become more active in the upcoming months. Plaintiffs' counsel is seeking a trial date in mid-2013.

Due to the current early stages of the LDR, Cudd and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. In each case management has determined the possibility of loss is remote. However, 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 and management cannot determine the amount of loss, if any, that may result.

11. 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 and forward sales contracts. These contracts allow the Company to predict with greater certainty the effective oil prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

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

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accompanying consolidated balance sheets as derivative assets and liabilities.

During the third quarter of 2011 and the first quarter of 2012, the Company entered into fixed price swap contracts for 2012 and 2013 with the purchaser of the Company’s WCBB oil and two financial institutions. The Company’s fixed price swap contracts are tied to the commodity prices on the International Petroleum Exchange (“IPE”). 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 IPE for Brent Crude. At June 30, 2012, the Company had the following fixed price swaps in place:

	Daily Volume (Bbls/day)	Weighted Average Price
July - December 2012	3,000	$109.73
January - June 2013	1,000	$113.20

At June 30, 2012 the fair value of derivative assets related to the fixed price swaps was as follows:

Short-term derivative instruments – asset	$9,714,000

All fixed price swaps and forward sales contracts 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, 2012 and 2011 are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Reduction to oil and condensate sales	(561,000)	(1,164,000)	$(461,000)	$(2,011,000)

The Company expects to reclassify $6,921,000 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, 2012 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 recognized a gain of $345,000 and $79,000 related to hedge ineffectiveness for the three months and six months ended June 30, 2012, respectively, which is included in oil and condensate sales in the consolidated statements of operations. The Company did not recognize into earnings any amount related to hedge ineffectiveness for the six months ended June 30, 2011.

12. 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.

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Level 3 – Significant inputs to the valuation model are unobservable.

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

The following table summarizes the Company's financial assets and liabilities by FASB ASC 820 valuation level as of June 30, 2012:

	As of June 30, 2012		
	Level 1	Level 2	Level 3
Assets:			
Fixed price swaps	$—	$9,714,000	$—
Liabilities:			
Fixed price swaps	$—	$—	$—

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, 2012 were approximately $1,176,000.

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.

13. SUBSEQUENT EVENTS

In July 2012, the Company entered into fixed price swap contracts for the period of August 2012 through December 2012 for 1,000 barrels of oil per day at a weighted average price of $99.98 per barrel. For the period of January 2013 through December 2013, the Company entered into fixed price swap contracts for 3,000 barrels of oil per day at a weighted average price of $100.04 per barrel. The Company's fixed price swap contracts are tied to the commodity prices on the IPE. 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 IPE for Brent Crude.

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

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

Disclosure Regarding Forward-Looking Statements

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

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. During 2010, we acquired our initial acreage position in the Niobrara Formation of northwestern Colorado. During 2011, we acquired our initial acreage position in the Utica Shale in Eastern Ohio and our first well in the Utica Shale was spud in February 2012. We have spud six additional wells in the Utica Shale since that time. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

Contribution

On May 7, 2012, we entered into a contribution agreement with Diamondback Energy, Inc., or Diamondback. Under the terms of the contribution agreement, we agreed to contribute to Diamondback, prior to the closing of Diamondback's initial public offering, or the Diamondback IPO, all our oil and gas interests in the Permian Basin in exchange for (i) shares of common stock representing 35% of Diamondback's outstanding common stock immediately prior to the closing of the Diamondback IPO and (ii) $63,590,050.00 in the form of a non-interest bearing promissory note, which will be repaid in full upon the closing of the Diamondback IPO with a portion of the net proceeds from that offering. The aggregate consideration payable to us is subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and other items of Windsor Permian LLC, or Windsor Permian, referred to in the contribution agreement as of the date of the contribution. Windsor Permian, an entity controlled by Wexford, is the operator of the acreage to be contributed by us and will be a wholly-owned subsidiary of Diamondback at the time of our contribution. Our obligation to make this contribution is contingent upon, among other things, the contribution to Diamondback of all the outstanding equity interests in Windsor Permian, our satisfaction with the terms of the Diamondback IPO and customary closing conditions. Under the contribution agreement, we are generally responsible for all liabilities and obligations with respect to the contributed properties arising prior to the contribution and Diamondback is responsible for such liabilities and obligations with respect to the contributed properties arising after the contribution.

In connection with the contribution, we and Diamondback will enter into an investor rights agreement in which we

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will have the right, for so long as we beneficially own more than 10% of Diamondback's outstanding common stock, to designate one individual as a nominee to serve on Diamondback's board of directors. Such nominee, if elected to Diamondback's board, will also serve on each committee of the board so long as he or she satisfies the independence and other requirements for service on the applicable committee of the board. So long as we have the right to designate a nominee to Diamondback's board and there is no Gulfport nominee actually serving as a Diamondback director, we will have the right to appoint one individual as an advisor to the board who shall be entitled to attend board and committee meetings. We will also be entitled to certain information rights and Diamondback will grant us certain demand and "piggyback" registration rights obligating Diamondback to register with the SEC any shares of Diamondback common stock that we own. If the contribution is completed, we will own a 35% equity interest in Diamondback immediately prior to the closing of the Diamondback IPO, rather than leasehold interests in our Permian Basin acreage.

Second Quarter 2012 Operational Highlights

- Oil and natural gas revenues increased 19% to $66.3 million for the three months ended June 30, 2012 from $55.5 million for the three months ended June 30, 2011.

- Net income decreased 8% to $25.1 million for the three months ended June 30, 2012 from $27.3 million for the three months ended June 30, 2011.

- Production increased 17% to approximately 664,000 barrels of oil equivalent, or BOE, for the three months ended June 30, 2012 from approximately 567,000 BOE for the three months ended June 30, 2011.

- During the three months ended June 30, 2012, we drilled 21 gross (18.4 net) wells and recompleted 17 gross and net wells. An additional ten gross (3.5 net) wells were drilled by our operators on the Permian Basin and Niobrara Formation. Of these 31 gross new wells at June 30, 2012, ten had been completed as producing wells, three were non-productive, 11 were waiting on completion, two were resting and five were being drilled.

- During 2011 and the first half of 2012, we acquired approximately 5,600 additional net acres in the Permian Basin. Our Permian Basin acreage is subject to the contribution agreement discussed under "—Contribution" above pursuant to which we agreed to contribute, subject to certain conditions, our interests in our Permian Basin acreage to Diamondback. If the contribution is completed, we will own a 35% equity interest in Diamondback immediately prior to the closing of the Diamondback IPO, rather than leasehold interests in our Permian Basin acreage.

- During 2011 and the first half of 2012, we acquired leasehold interests in approximately 116,000 gross (58,000 net) acres in the Utica Shale in Eastern Ohio. We have commitments with various future closing dates which could increase our acreage position in the Utica Shale to an aggregate of approximately 125,000 gross (62,500 net) leasehold acres. We spud our first well on our Utica Shale acreage in February 2012 and subsequently have spud six additional wells. In August 2012, the first well was brought online, testing at a gross peak rate of 17.1 million cubic feet of natural gas per day, 432 barrels of condensate per day and 1,881 barrels of natural gas liquids per day assuming full ethane recovery and a natural gas shrink of 18%, or 4,650 BOE per day.

- In connection with our scheduled spring 2012 borrowing base redetermination completed on May 2, 2012, the borrowing base under our revolving credit facility was increased from $125.0 million to $155.0 million. In addition, three new lenders were added to the bank syndicate, Credit Suisse, Deutsche Bank Trust Company Americas and Iberiabank, and Société Générale left the bank group.

2012 Production and Drilling Activity

During the three months ended June 30, 2012, our total net production was 608,000 barrels of oil, 216,000 thousand cubic feet, or Mcf, of gas, and 804,000 gallons of liquids, for a total of 664,000 BOE as compared to 493,000 barrels of oil, 331,000 Mcf of gas and 819,000 gallons of liquids, or 567,000 BOE, for the three months ended June 30, 2011. Our total net production averaged approximately 7,293 BOE per day during the three months ended June 30, 2012 as compared to 6,234 BOE per day during the same period in 2011. The 17% increase in production is primarily related to the 2012 drilling and recompletion activities in our fields.

WCBB. From January 1, 2012 through August 1, 2012, we recompleted 26 existing wells. We also spud 18 wells, of which 14 were completed as producers and two were non-productive and, at August 1, 2012, one was waiting on completion and one was being drilled. We currently intend to recomplete a total of approximately 60 existing wells and drill a total of 22 to

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24 wells during 2012.

Aggregate net production from the WCBB field during the three months ended June 30, 2012 was 308,028 BOE, or 3,385 BOE per day, 96% of which was from oil and 4% of which was from natural gas. During July 2012, our average daily net production at WCBB was approximately 3,176 BOE, 96% of which was from oil and 4% of which was from natural gas. The decrease in July 2012 production was the result of the timing of 2012 drilling and recompletion activities and normal production declines.

East Hackberry Field. From January 1, 2012 through August 1, 2012, we recompleted 15 existing wells. We also spud 15 wells, of which nine were completed as producers and two were non-productive and, at August 1, 2012, two were 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. We currently intend to drill 20 wells and recomplete 20 wells in our East Hackberry field in 2012.

Aggregate net production from the East Hackberry field during the three months ended June 30, 2012 was approximately 236,508 BOE, or 2,599 BOE per day, 97% of which was from oil and 3% of which was from natural gas. During July 2012, our average daily net production at East Hackberry was approximately 2,632 BOE, 98% of which was from oil and 2% of which was from natural gas. The increase in July 2012 production was the result of the 2012 drilling and recompletion activities.

West Hackberry Field. Aggregate net production from the West Hackberry field during the three months ended June 30, 2012 was approximately 2,776 BOE, or 31 BOE per day. During July 2012, our average daily net production at West Hackberry was approximately 37 BOE, 100% of which was from oil.

Permian Basin. From January 1, 2012 to August 1, 2012, 17 gross (7.3 net) wells, including our first horizontal well, were spud on our Permian Basin acreage, of which 11 gross (4.4 net) wells were completed as producers, five gross (2.4 net) wells were waiting on completion and one gross (0.5 net) well was being drilled at August 1, 2012. One gross (0.3 net) existing well was recompleted from January 1, 2012 to August 1, 2012. We currently anticipate that a total of 23 to 25 gross (11.5 to 12.5 net) wells will be drilled and five gross (2.5 net) wells will be recompleted on this acreage during 2012.

Aggregate net production from our Permian Basin acreage during the three months ended June 30, 2012 was approximately 102,643 BOE, or 1,128 BOE per day. During July 2012, the average daily net production from our Permian Basin acreage was approximately 1,155 BOE, of which approximately 68% was oil, 18% was natural gas liquids and 14% was natural gas. The increase in July 2012 production was due to our 2012 drilling activity.

Our Permian Basin acreage is subject to the contribution agreement discussed under "—Contribution" above pursuant to which we agreed to contribute, subject to certain conditions, our interest in our Permian Basin acreage to Diamondback. If the contribution is completed, we will own a 35% equity interest in Diamondback immediately prior to the closing of the Diamondback IPO, rather than leasehold interests in our Permian Basin acreage.

Niobrara Formation. Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara formation in Colorado and held leases for approximately 14,713 acres as of June 30, 2012. From January 1, 2012 through August 1, 2012, we spud one gross (0.5 net) well which, at August 1, 2012, was waiting on completion. Aggregate net production from the Niobrara play during the three months ended June 30, 2012 was approximately 4,544 BOE, or 50 BOE per day, 100% of which was from oil. During July 2012, average daily net production in Niobrara was approximately 48 BOE due to completion of our 2011 drilling activity.

We have completed a 60 square mile 3-D seismic survey over our Craig Dome prospect, have received a processed version of the seismic and have selected future drilling locations. We currently intend to drill five to seven gross wells at Niobrara during 2012.

Bakken. In the Bakken formation, as of June 30, 2012, we held approximately 900 net acres, interests in seven wells and overriding royalty interests in certain existing and future wells.

Aggregate net production from the Bakken formation during the three months ended June 30, 2012 was approximately 8,905 BOE, or 98 BOE per day. During July 2012, our average daily net production from the Bakken formation was approximately 74 BOE. There are no new activities currently scheduled for 2012 for our Bakken acreage.

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Utica Shale (Eastern Ohio). As of June 30, 2012, we had acquired leasehold interests in approximately 116,000 gross (58,000 net) acres in the Utica Shale in Eastern Ohio. As of July 31, 2012 we closed on additional acquisitions bringing our total leasehold interest to approximately 118,000 gross (59,000 net) acres. We have commitments with various future closing dates that could increase our acreage position in the Utica Shale to an aggregate of approximately 125,000 gross (62,500 net) leasehold acres. We have spud seven wells on our Utica Shale acreage since February 2012, the first of which was brought online in August 2012 and tested at a gross peak rate of 17.1 million cubic feet of natural gas per day, 432 barrels of condensate per day and 1,881 barrels of natural gas liquids per day assuming full ethane recovery and a natural gas shrink of 18%, or 4,650 BOE per day. We currently expect to drill approximately 20 gross (ten net) wells during 2012, of which we expect ten gross (five net) to be completed by year end.

Grizzly. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by an entity controlled by Wexford. As of June 30, 2012, Grizzly had approximately 800,000 acres under lease in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. Our total net investment in Grizzly was approximately $144.8 million as of June 30, 2012. As of that date, Grizzly had drilled an aggregate of 232 core holes and seven water supply test wells, tested eleven 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. In November 2011, the Government of Alberta provided a formal Order-in Council authorizing the Alberta Energy Resources Conservation Board (ERCB) to issue the formal regulatory approval of Grizzly's Algar Lake SAGD project. During the second quarter of 2012, Grizzly finished SAGD well pair drilling at Algar Lake and began the process of completing those well pairs for SAGD injection and production. In the first quarter of 2012, Grizzly completed the acquisition of approximately 47,000 acres through the purchase of its May River property and recently set forth a full field development plan for this property under which May River will be developed in multiple phases with the goal of producing 70,000 barrels per day of bitumen by the year 2020. Grizzly's contemplated 2012 activities included the completion of the 2011/2012 core hole drilling and seismic program, submission of a SAGD project regulatory application for Thickwood Hills and the development of its Algar Lake SAGD project, which included the fabrication and onsite construction of a central processing facility and the drilling of ten initial SAGD well pairs which has now been completed.

Thailand. We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. The remaining interests in Tatex II are owned by entities controlled by Wexford. Tatex II, 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 approximately two million acres which includes the Phu Horm Field. As of June 30, 2012, our net investment in Tatex II was $0.8 million. Our investment is accounted for on the equity method. Tatex II accounts for its investment in APICO using the cost method. During the second quarter ended June 30, 2012, net gas production from the Phu Horm field was approximately 101 MMcf per day and condensate production was 476 barrels 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 II 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 II'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. Tatex III owns a concession covering approximately one million acres. During the six months ended June 30, 2012, we paid $0.6 million in cash calls, bringing our total investment in Tatex III to $8.8 million. 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. During testing, the well produced at rates as high as 16 million cubic feet per day of gas for short intervals, but would subsequently fall to a sustained rate of two million cubic feet per day. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. Despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. Tatex III intends to continue testing some of the structures identified through its 3-D seismic survey and has begun the application process for two more drilling locations. Tatex III currently expects to drill the first of these wells, located to the south of the TEW-E well, in 2013.

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

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

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. 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 applicable period, 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 of proved undeveloped properties 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 $199.6 million at June 30, 2012 and $138.6 million at December 31, 2011. 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 applicable period, 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, 2012.

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

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

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

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Ryder Scott Company and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2011 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. Therefore, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management’s opinion, it is more likely than not that some portion will not be realized. At June 30, 2012, a valuation allowance of $12.3 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

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Hedging," as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

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

To mitigate the effects of commodity price fluctuations, 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 for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29. For the period from January 2013 through June 2013, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $103.33 per barrel. For the period from July 2013 through December 2013, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $100.04. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 38% to 41% of our estimated 2012 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.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended June 30, 2012 and 2011

We reported net income of $25,117,000 for the three months ended June 30, 2012, as compared to $27,265,000 for the three months ended June 30, 2011. This 8% decrease in period-to-period net income was due primarily to a 21% increase in lease operating expenses, a 54% increase in general and administrative expenses and a 12% increase in production taxes, partially offset by a 17% increase in net production to 664,000 BOE from 567,000 BOE and a 2% increase in realized BOE prices to $99.84 from $97.77 for the quarter ended June 30, 2012 as compared to the quarter ended June 30, 2011.

Oil and Gas Revenues. For the three months ended June 30, 2012, we reported oil and natural gas revenues of $66,255,000 as compared to oil and natural gas revenues of $55,462,000 during the same period in 2011. This $10,793,000, or 19%, increase in revenues is primarily attributable to a 17% increase in net production to 664,000 BOE from 567,000 BOE and a 2% increase in realized BOE prices to $99.84 from $97.77 for the quarter ended June 30, 2012 as compared to the quarter ended June 30, 2011.

The following table summarizes our oil and natural gas production and related pricing for the three months ended June 30, 2012, as compared to such data for the three months ended June 30, 2011:

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	Three Months Ended June 30,	
	2012	2011
Oil production volumes (MBbls)	608	493
Gas production volumes (MMcf)	216	331
Liquid production volumes (MGal)	804	819
Oil equivalents (Mboe)	664	567
Average oil price (per Bbl)	$106.86	$107.40
Average gas price (per Mcf)	$2.50	$4.57
Average liquids price (per gallon)	$0.86	$1.26
Oil equivalents (per Boe)	$99.84	$97.77

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $5,714,000 for the three months ended June 30, 2012 from $4,706,000 for the same period in 2011. This increase is primarily the result of an increase in expenses related to contract labor, repairs and maintenance, property taxes, testing and inspection and salt-water disposal.

Production Taxes. Production taxes increased to $7,572,000 for the three months ended June 30, 2012 from $6,732,000 for the same period in 2011. This increase was primarily related to a 17% increase in production and a 2% increase in the average realized BOE price received, resulting in a 19% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $23,652,000 for the three months ended June 30, 2012, and consisted of $23,536,000 in depletion on oil and natural gas properties and $116,000 in depreciation of other property and equipment, as compared to total DD&A expense of $13,712,000 for the three months ended June 30, 2011. 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 and a decrease in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $3,263,000 for the three months ended June 30, 2012 from $2,119,000 for the same period in 2011. This $1,144,000 increase was due primarily to an increase in franchise taxes as well as increases in salaries, stock compensation and benefits resulting from an approximate 70% increase in the number of employees primarily attributable to the acquisition of our acreage in the Utica Shale and increases in legal expenses, partially offset by an increase in administrative services reimbursements under the acquisition team agreement relating to the Utica acreage and an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $177,000 for the three months ended June 30, 2012 from $164,000 for the same period in 2011.

Interest Expense. Interest expense increased to $474,000 for the three months ended June 30, 2012 from $285,000 for the same period in 2011 due to an increase in total weighted debt outstanding under our revolving credit facility. Total weighted debt outstanding was $41,769,000 for the three months ended June 30, 2012, as compared to $18,462,000 for the same period in 2011. We had $68,000,000 of total debt outstanding under our revolving credit facility as of June 30, 2012. As of June 30, 2012, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 2.49%.

Income Taxes. As of June 30, 2012, we had a net operating loss carry forward of approximately $116,800,000, 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, 2012, a valuation allowance of $12,347,000 had been provided for deferred tax assets, with the exception of $1,000,000 related to alternative minimum taxes. We had no income tax expense for the three months ended June 30, 2012.

Comparison of the Six Months Ended June 30, 2012 and 2011

We reported net income of $51,986,000 for the six months ended June 30, 2012, as compared to $48,439,000 for the

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six months ended June 30, 2011. This 7% increase in period-to-period net income was due primarily to a 21% increase in net production to 1,309,000 BOE and a 7% increase in realized BOE prices to $100.62 for the six months ended June 30, 2012 from $94.36 for the same period in 2011, partially offset by a 24% increase in lease operating expenses, a 50% increase in general and administrative expenses and a 25% increase in production taxes for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011.

Oil and Gas Revenues. For the six months ended June 30, 2012, we reported oil and natural gas revenues of $131,678,000 as compared to oil and natural gas revenues of $102,037,000 during the same period in 2011. This $29,641,000, or 29%, increase in revenues is primarily attributable to a 21% increase in net production to 1,309,000 BOE from 1,081,000 BOE and a 7% increase in realized BOE prices to $100.62 from $94.36 for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011.

The following table summarizes our oil and natural gas production and related pricing for the six months ended June 30, 2012, as compared to such data for the six months ended June 30, 2011:

	Six Months Ended June 30,	
	2012	2011
Oil production volumes (MBbls)	1,204	965
Gas production volumes (MMcf)	427	495
Liquid production volumes (MGal)	1,429	1,428
Oil equivalents (Mboe)	1,309	1,081
Average oil price (per Bbl)	$107.20	$101.69
Average gas price (per Mcf)	$2.70	$4.51
Average liquids price (per gallon)	$1.05	$1.19
Oil equivalents (per Boe)	$100.62	$94.36

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $11,563,000 for the six months ended June 30, 2012 from $9,359,000 for the same period in 2011. This increase is mainly the result of an increase in expenses related to chemicals and fuel, compressor rentals, contract labor, ad valorem taxes, salt water hauling and disposal, rentals, testing and inspection, equipment repairs and maintenance and field supervision.

Production Taxes. Production taxes increased to $15,341,000 for the six months ended June 30, 2012 from $12,239,000 for the same period in 2011. This increase was primarily related to a 21% increase in production and a 7% increase in the average realized BOE price received resulting in a 29% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $45,047,000 for the six months ended June 30, 2012, and consisted of $44,823,000 in depletion on oil and natural gas properties and $224,000 in depreciation of other property and equipment, as compared to total DD&A expense of $25,870,000 for the six months ended June 30, 2011. 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 $6,272,000 for the six months ended June 30, 2012 from $4,175,000 for the same period in 2011. This $2,097,000 increase was primarily due to an increase in franchise taxes, increases in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, corporate fees and bank fees, 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 $353,000 for the six months ended June 30, 2012 from $323,000 for the same period in 2011.

Interest Expense. Interest expense decreased to $627,000 for the six months ended June 30, 2012 from $938,000 for the same period in 2011 due to a decrease in the average debt outstanding under our revolving credit facility, slightly offset by an increase in the interest rate paid. Total weighted debt outstanding under our facility was $21,049,000 for the six months

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ended June 30, 2012 and $35,776,000 for the same period in 2011. As of June 30, 2012, we had $68,000,000 of total debt outstanding under our revolving credit facility. As of June 30, 2012, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 2.49%.

Income Taxes. As of June 30, 2012, we had a net operating loss carry forward of approximately $116,800,000, 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, 2012, a valuation allowance of $12,347,000 had been provided for deferred tax assets, with the exception of $1,000,000 related to alternative minimum taxes. We paid no state taxes for the six months ended June 30, 2012.

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. In the first quarter of 2011, we received net proceeds (before offering expenses) of approximately $84,346,000 from the sale of our common stock. We did not sell any equity securities during the six months ended June 30, 2012.

Net cash flow provided by operating activities was $99,497,000 for the six months ended June 30, 2012, as compared to net cash flow provided by operating activities of $65,401,000 for the same period in 2011. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 7% increase in net realized prices and a 21% increase in our net BOE production.

Net cash used in investing activities for the six months ended June 30, 2012 was $254,266,000 as compared to $127,427,000 for the same period in 2011. During the six months ended June 30, 2012, we spent $150,653,000 in additions to oil and natural gas properties, of which $44,763,000 was spent on our 2012 drilling and recompletion programs, $35,638,000 was spent on expenses attributable to the wells drilled and recompleted during 2011, $2,883,000 was spent on compressors and other facility enhancements, $994,000 was spent on plugging costs, $58,713,000 was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and $2,212,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $78,312,000, $626,000, $2,244,000, $1,000,000, $7,595,000, $7,525,000, $4,027,000, $291,000 and $244,000 was invested in Grizzly, Tatex III, Muskie Holdings LLC, Timber Wolf Terminals LLC, Windsor Midstream LLC, Bison Drilling and Field Services LLC, Stingray Pressure Pumping LLC, Stingray Cementing LLC and Blackhawk Midstream LLC, respectively, during the six months ended June 30, 2012. In addition, $1,594,000 was loaned to Bison Drilling and Field Services LLC during the six months ended June 30, 2012. During the six months ended June 30, 2012, we used cash from operations for our investing activities.

Net cash provided by financing activities for the six months ended June 30, 2012 was $67,485,000 as compared to net cash provided by financing activities of $64,236,000 for the same period in 2011. The 2012 amount provided by financing activities is primarily attributable to net borrowings under our revolving line of credit. The 2011 amount provided by financing activities is primarily attributable to the net proceeds of $84,346,000 from our equity offering offset by net principal payments of $19,500,000 on borrowings under our credit facilities.

Credit Facility. On September 30, 2010, we entered into a $100.0 million senior secured revolving credit facility 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. On May 3, 2011, we entered into a first amendment to the revolving credit facility with the Bank of Nova Scotia, Amegy Bank, KeyBank National Association, or KeyBank, and Société Générale. Pursuant to the terms of the first amendment, KeyBank 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 facility were decreased, and the maturity date was extended until May 3, 2015. On October 31, 2011, we entered into additional amendments to our revolving credit facility pursuant to which, among other things, the borrowing base under this facility was increased to $125.0 million. On December 14, 2011, we repaid all outstanding borrowings under this credit facility with a portion of the net proceeds of our equity offering completed on December 5, 2011 pending the application of such proceeds to fund our additional Utica Shale lease acquisitions and for general corporate purposes. We subsequently re-borrowed amounts under our revolving credit facility and, as of June 30, 2012, had $68,000,000 of indebtedness outstanding under our revolving credit facility. Our revolving credit facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guaranteed our

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obligations under the revolving credit facility.

Advances under our revolving credit facility, 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. As of June 30, 2012, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate (2.49%).

Our revolving credit facility 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 facility. The credit facility 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, 2012.

In connection with our scheduled spring 2012 borrowing base redetermination completed on May 2, 2012, we entered into an amendment to our revolving credit facility pursuant to which, among other things, our borrowing base under this facility was increased to $155.0 million. In addition, three new lenders were added to the bank syndicate, Credit Suisse, Deuteshe Bank Trust Company Americas and Iberiabank, and Société Générale left the bank group. If we complete the contribution to Diamondback of our oil and natural gas assets located in the Permian Basin, our borrowing base will be reduced.

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 extended the maturity date of the building loan to February 2016 and reduced 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, 2012, approximately $2.2 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions, primarily in the Permian Basin, the Niobrara Formation and Utica Shale, and to fund Grizzly's delineation drilling program and initial preparation of the Algar Lake facility. 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) pursue acquisition and disposition opportunities.

Of our net reserves at December 31, 2011, 56% 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 Permian Basin acreage is subject to the contribution agreement discussed under "—Contribution" above pursuant to which we agreed to contribute, subject to certain conditions, our interest in our Permian Basin acreage to Diamondback. If the contribution is completed, we will own a 35% equity interest in Diamondback immediately prior to the closing of the Diamondback IPO, rather than leasehold interests in our Permian Basin acreage, resulting in a decrease in our total proved reserves. This decrease in total proved reserves is expected to result in a reduction in our borrowing base available under our

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revolving credit facility.

At December 31, 2011, our booked inventory of prospects included approximately 24 drilling locations at WCBB. The drilling schedule used in our December 31, 2011 reserve report anticipates that all of those wells will be drilled by 2015. From January 1, 2012 through August 1, 2012, we recompleted 26 existing wells and spud 18 new wells at our WCBB field, of which 14 were completed as producers, two were non-productive, and at August 1, 2012, one was waiting on completion and one was being drilled. We currently intend to recomplete 60 wells and drill 22 to 24 new wells during 2012. Our aggregate drilling and recompletion expenditures for our WCBB field during 2012 are estimated to be approximately $36.0 million to $38.0 million.

From January 1, 2012 through August 1, 2012, we recompleted 15 existing wells and spud 15 new wells at our East Hackberry field, of which nine were completed as producers, two were non-productive, and at August 1, 2012, two were waiting on completion and two were being drilled. We currently intend to drill 20 wells and recomplete 20 wells in our East Hackberry field in 2012. Total capital expenditures for our East Hackberry field during 2012 are estimated to be approximately $36.0 million to $38.0 million.

In the Permian Basin, our booked inventory of prospects at December 31, 2011 included 252 gross (124 net) future development drilling locations. From January 1, 2012 through August 1, 2012, 17 gross (7.3 net) wells were spud on this acreage, of which 11 gross (4.4 net) wells were completed as producers, five gross (2.4 net) were waiting on completion and one gross (0.5 net) well was being drilled at August 1, 2012. One gross (0.3 net) existing well was recompleted from January 1, 2012 to August 1, 2012. We currently anticipate that our capital requirements to drill a total of 23 to 25 gross (11.5 to 12.5 net) wells and recomplete five gross (2.5 net) wells in the Permian Basin in West Texas will be approximately $23.0 million to $25.0 million in 2012. Our Permian Basin acreage is subject to the contribution agreement discussed under "—Contribution" above pursuant to which we agreed to contribute, subject to certain conditions, our interest in our Permian Basin acreage to Diamondback. If the contribution is completed, we will own a 35% equity interest in Diamondback immediately prior to the closing of the Diamondback IPO, rather than leasehold interests in our Permian Basin acreage.

In the Niobrara Formation in northwestern Colorado, in 2011, we completed a 60 square mile 3-D seismic survey, have received a processed version of the seismic and have selected future drilling locations. From January 1, 2012 through August 1, 2012, we spud one gross (0.5 net) well which, at August 1, 2012, was waiting on completion. We currently anticipate that our total capital expenditures in the Niobrara Formation will be approximately $5.0 million to $6.0 million in 2012 to drill five to seven gross wells. Our net interest in each of these wells will be less than 50%.

In the Utica shale in Ohio, in 2011 and the first quarter of 2012, we acquired approximately 116,000 gross (58,000 net) acres for $169.8 million. As of July 31, 2012, we closed on additional acquisitions bringing our total leasehold interests in the Utica Shale to approximately 118,000 gross (59,000 net) acres. We have commitments with various future closing dates that could increase our acreage position in the Utica Shale to approximately 125,000 gross (62,500 net) leasehold acres. We have spud seven wells on our Utica Shale acreage since February 2012. Our total lease acquisition costs in the Utica shale during 2012 are estimated to be $70.0 million to $75.0 million, of which approximately $51.7 million was spent in the first half of 2012. In addition, during 2012, we currently anticipate spending another $72.0 million to $76.0 million to drill 20 gross (ten net) wells, of which we expect ten gross (five net) to be completed by year end.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of June 30, 2012, our net investment in Grizzly was approximately $144.8 million. Our capital requirements in 2012 for Grizzly are estimated to be approximately $40.0 million to $43.0 million, primarily for the expenses associated with the construction of the Algar Lake facility and drilling activity during the 2011-2012 winter drilling season. In addition, in February 2012, Grizzly purchased approximately 47,000 acres of oil sands leases in the Athabasca oil sands area for $225.0 million CAD. Our capital contribution obligation to Grizzly for our portion of the purchase price was approximately $56.3 million. We funded this amount with borrowings under our revolving credit facility.

We do not anticipate any capital expenditures in 2012 related to our interests in Thailand.

Our total capital expenditures for our 2012 drilling activities described above are currently estimated to be in the range of $212.0 million to $226.0 million, of which approximately $81.5 million was spent in the first six months of 2012. This range for 2012 is up from the $130.0 million spent on 2011 activities 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.

In an effort to facilitate the development of our Utica, Permian Basin and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In March 2012, we acquired a 50% equity interest

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in Timber Wolf Terminals LLC, or Timber Wolf, for $1.0 million. Timber Wolf will operate a crude/condensate terminal and sand transloading facility in Ohio. Also in March 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC, or Midstream, for $7.0 million. Midstream owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011, we acquired a 25% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. In April 2012, we purchased an additional 15% equity interest for approximately $6.2 million, bringing our total ownership interest in Bison to 40%. Also in 2011, we acquired a 25% interest in Muskie Holdings LLC, or Muskie, which is engaged in the mining of hydraulic fracturing grade sand. In the second quarter of 2012, we acquired a 50% equity interest in each of Stingray Pressure Pumping LLC, or Stingray Pressure, and Stingray Cementing LLC, or Stingray Cementing. Stingray Pressure and Stingray Cementing will provide well completion services. We also acquired a 50% equity interest in Blackhawk Midstream LLC in connection with the development of our Utica acreage. The remaining equity interests in these entities are owned by affiliates of Wexford. In 2012, we expect to invest approximately $30.0 million to $35.0 million in these entities.

We believe that our cash on hand, cash flow from operations and borrowings under our revolving credit facility will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue additional acquisitions or accelerate our Canadian oil sands project, we may 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. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

To mitigate the effects of commodity price fluctuations, 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 for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29. For the period from January 2013 through June 2013, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $103.33 per barrel. For the period from July 2013 through December 2013, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $100.04. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 38% to 41% of our estimated 2012 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 can access the trust for use in plugging and abandonment charges associated with the property. As of June 30, 2012, the plugging and abandonment trust totaled approximately $3.1 million. At June 30, 2012, we have plugged 354 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. The adoption did not have a material impact on our consolidated financial statements.

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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. The components of other comprehensive income and total comprehensive income are presented in the accompanying consolidated statements of comprehensive income (loss).

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, during the past five years, 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 barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On July 31, 2012, the West Texas Intermediate posted price for crude oil was $88.06 per barrel and the Henry Hub spot market price of natural gas was $3.21 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

To mitigate the effects of commodity price fluctuations, in 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 for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29. For the period from January 2013 through June 2013, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $103.33 per barrel. For the period from July 2013 through December 2013, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $100.04. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 38% to 41% of our estimated 2012 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, 2012, we had a net asset derivative position of $9.7 million as compared to a net liability derivative position of $3.4 million as of June 30, 2011, 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 $7.1 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by $7.1 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, 2012, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 2.49%. Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $680,000 per year, based on $68.0 million outstanding under our revolving credit facility as of June 30, 2012. As of June 30, 2012, 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, 2012, 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, 2012, 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 LDR had taken no further action on this lawsuit since filing its petition until recently when it propounded discovery requests to which we have responded. Since we served discovery requests on the LDR and received the LDR's responses, there has been no further activity on the case and no trial date has been set.

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, but has taken no action to initiate settlement talks. There has been no activity on either of these lawsuits for more than a year.

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. In 2011 and 2012, the parties engaged in extensive discovery and motion practice. On July 5, 2012, Cudd filed a fourth amended petition, which largely tracks the prior petitions but adds two additional causes of action and provides more detailed information regarding the damages Cudd is seeking. Among other things, Cudd claims the defendants, including us, owe $11.8 million as a reasonable royalty for the alleged use of its trade secrets. Cudd also seeks disgorgement of the alleged benefits received by the various defendants. Cudd has not quantified the benefit it seeks to have us disgorge, but has alleged that we received from Wexford the opportunity to participate in Wexford's deals on a special no cost basis in exchange for participating in the alleged conduct. Cudd also seeks its attorney's fees, which Cudd claims is not less than $450,000 plus 10% of any final judgment. We deny all of Cudd's claims. All parties have filed motions for summary judgment which have not yet been heard by the Court. The case is currently set to go to trial on September 5, 2012.

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 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. In addition to us, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions on several grounds 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 similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, we and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. Some of the defendants' grounds for challenging the plaintiffs' petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. We noticed our intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. We filed our supervisory writ, which was recently denied by the Louisiana Third Circuit Court of Appeal. We filed a writ to the Louisiana Supreme Court on this issue, and there has not yet been a ruling. We have been active in serving discovery requests and responding to discovery requests from the plaintiffs. It is anticipated that the discovery phase of this case will become more active in the upcoming months. Plaintiffs' counsel is seeking a trial date in mid-2013.

Due to the current early stages of the LDR, Cudd and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. In each case, management has determined the possibility of loss is remote. However, 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 and management cannot determine the amount of loss, if any, that may result.

We have been named as a defendant in various other lawsuits related to our business. The ultimate resolution of these matters is not expected to have a material adverse effect on our financial condition or results of operations.

ITEM 1A. RISK FACTORS.

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See risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

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, 2012, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

ITEM 5. OTHER INFORMATION

(a)On June 7, 2012, we held our 2012 Annual Meeting of Stockholders at our corporate headquarters in Oklahoma City, OK. The following matters set forth in our definitive proxy statement on Schedule 14A filed with the Securities and Exchange Commission on April 30, 2012 and distributed to the Company's stockholders on or about May 10, 2012 were voted on at the 2012 Annual Meeting and the results of such voting are indicated below.

Proposal 1

Mike Liddell, Donald L. Dillingham, Craig Groeschel, David L. Houston, James D. Palm and Scott E. Streller were elected to continue to serve as our directors until the 2013 Annual Meeting of Stockholders and until their respective successors are elected. The results of the vote on Proposal 1 were as follows:

Name of Nominee	For	Withheld	Non Votes
Mike Liddell	45,627,129	3,058,159	4,317,125
Donald L. Dillingham	48,280,019	405,269	4,317,125
Craig Groeschel	48,327,263	358,025	4,317,125
David L. Houston	44,746,290	3,938,998	4,317,125
James D. Palm	47,215,292	1,469,996	4,317,125
Scott E. Streller	39,319,538	9,365,750	4,317,125

Proposal 2

Our stockholders approved, on an advisory basis, the Company's executive compensation. The results of the vote on Proposal 2 were as follows:

For	Against	Abstain	Non Votes
45,930,329	2,720,773	34,186	4,317,125

Proposal 3

The appointment of Grant Thornton LLP as our independent auditors for the fiscal year ending December 31, 2012 was ratified. The results of the vote on Proposal 3 were as follows:

For	Against	Abstain
52,903,028	75,953	23,432