GULFPORT ENERGY CORP
Form 10-Q
August 07, 2014
Table of Contents

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014 OR

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

For the transition period from to

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)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The NASDAQ Stock Market LLC

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 preceding 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 (Section 232.405 of this chapter) during the preceding 12 months (or 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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ý 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, 2014, 85,499,465 shares of the registrant's common stock were outstanding.

Table of Contents

GULFPORT ENERGY CORPORATION
TABLE OF CONTENTS

1

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$75,293	$458,956
Accounts receivable—oil and gas	107,455	58,824
Accounts receivable—related parties	127	2,617
Prepaid expenses and other current assets	3,575	2,581
Deferred tax asset	7,661	6,927
Short-term derivative instruments	—	324
Note receivable - related party	875	875
Total current assets	194,986	531,104
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $1,187,637 and $950,590 excluded from amortization in 2014 and 2013, respectively	3,201,529	2,477,178
Other property and equipment	12,605	11,131
Accumulated depletion, depreciation, amortization and impairment	(897,553)	(784,717)
Property and equipment, net	2,316,581	1,703,592
Other assets:		
Equity investments ($211,300 and $178,708 attributable to fair value option in 2014 and 2013, respectively)	501,436	440,068
Derivative instruments	784	521
Other assets	17,985	17,851
Total other assets	520,205	458,440
Total assets	$3,031,772	$2,693,136
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$287,458	$190,707
Asset retirement obligation—current	795	795
Short-term derivative instruments	24,532	12,280
Current maturities of long-term debt	163	159
Total current liabilities	312,948	203,941
Long-term derivative instrument	5,487	11,366
Asset retirement obligation—long-term	15,181	14,288
Deferred tax liability	170,559	114,275
Long-term debt, net of current maturities	339,098	299,028
Total liabilities	843,273	642,898
Commitments and contingencies (Note 8)		
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, 200,000,000 authorized, 85,494,966 issued and outstanding in 2014 and 85,177,532 in 2013	854	851
Paid-in capital	1,821,368	1,813,058

Accumulated other comprehensive loss	(10,243)	(9,781)
Retained earnings	376,520	246,110
Total stockholders' equity	2,188,499	2,050,238
Total liabilities and stockholders' equity	$3,031,772	$2,693,136

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(In thousands, except share data)			
Revenues:				
Oil and condensate sales	$68,078	$60,999	$141,455	$114,079
Gas sales	35,522	6,793	53,871	8,259
Natural gas liquid sales	10,897	2,404	37,033	2,728
Other income	239	238	406	368
	114,736	70,434	232,765	125,434
Costs and expenses:				
Lease operating expenses	12,680	5,878	24,309	11,050
Production taxes	6,601	6,440	13,558	13,310
Midstream processing and marketing	10,780	1,901	18,549	2,318
Depreciation, depletion and amortization	55,994	28,540	112,871	51,123
General and administrative	10,382	4,900	19,893	9,312
Accretion expense	189	174	377	349
(Gain) loss on sale of assets	—	145	(11)	572
	96,626	47,978	189,546	88,034
INCOME FROM OPERATIONS	18,110	22,456	43,219	37,400
OTHER (INCOME) EXPENSE:				
Interest expense	2,402	3,284	6,287	6,763
Interest income	(36)	(62)	(142)	(141)
Litigation settlement	6,000	—	24,000	—
Income from equity method investments	(69,569)	(50,108)	(198,044)	(111,318)
	(61,203)	(46,886)	(167,899)	(104,696)
INCOME BEFORE INCOME TAXES	79,313	69,342	211,118	142,096
INCOME TAX EXPENSE	31,461	25,514	80,708	53,709
NET INCOME	$47,852	$43,828	$130,410	$88,387
NET INCOME PER COMMON SHARE:				
Basic	$0.56	$0.57	$1.53	$1.18
Diluted	$0.56	$0.56	$1.52	$1.17
Weighted average common shares outstanding—Basic	85,448,678	77,428,605	85,354,566	75,142,113
Weighted average common shares outstanding—Diluted	85,805,896	77,906,787	85,766,679	75,599,608

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Net income	$47,852	$43,828	$130,410	$88,387
Foreign currency translation adjustment	6,816	(6,113)	(462)	(9,680)
Change in fair value of derivative instruments (1)	—	356	—	(1,074)
Reclassification of settled contracts (2)	—	1,404	—	3,201
Other comprehensive income (loss)	6,816	(4,353)	(462)	(7,553)
Comprehensive income	$54,668	$39,475	$129,948	$80,834

(1) Net of $0.0 million and $0.0 million in taxes for the three and six months ended June 30, 2014, respectively, and net of $0.2 million and $(0.7) million in taxes for the three and six months ended June 30, 2013, respectively.

(2) Net of $0.0 million and $0.0 million in taxes for the three and six months ended June 30, 2014, respectively, and net of $0.9 million and $2.0 million in taxes for the three and six months ended June 30, 2013, respectively.

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Common Stock		Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
	(In thousands, except share data)					
Balance at January 1, 2014	85,177,532	$851	$1,813,058	$ (9,781)	$246,110	$2,050,238
Net income	—	—	—	—	130,410	130,410
Other Comprehensive Loss	—	—	—	(462)	—	(462)
Stock Compensation	—	—	7,665	—	—	7,665
Issuance of Restricted Stock	124,526	1	(1)	—	—	—
Issuance of Common Stock through exercise of options	192,908	2	646	—	—	648
Balance at June 30, 2014	85,494,966	$854	$1,821,368	$ (10,243)	$376,520	$2,188,499
Balance at January 1, 2013	67,527,386	$674	$1,036,245	$ (3,429)	$92,918	$1,126,408
Net income	—	—	—	—	88,387	88,387
Other Comprehensive Loss	—	—	—	(7,553)	—	(7,553)
Stock Compensation	—	—	3,004	—	—	3,004
Issuance of Common Stock in public offerings, net of related expenses	9,812,500	99	357,541	—	—	357,640
Issuance of Restricted Stock	82,720	1	(1)	—	—	—
Issuance of Common Stock through exercise of options	125,000	1	1,399	—	—	1,400
Balance at June 30, 2013	77,547,606	$775	$1,398,188	$ (10,982)	$181,305	$1,569,286

See accompanying notes to consolidated financial statements.

Table of Contents

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six months ended June 30,	
	2014	2013
	(In thousands)	
Cash flows from operating activities:		
Net income	$130,410	$88,387
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion of discount—Asset Retirement Obligation	377	349
Depletion, depreciation and amortization	112,871	51,123
Stock-based compensation expense	4,599	1,803
Gain from equity investments	(113,257)	(111,113)
Interest income - note receivable	(25)	
Unrealized loss (gain) on derivative instruments	6,433	(5,354)
Deferred income tax expense	55,550	53,709
Amortization of loan commitment fees	637	505
Amortization of note discount and premium	158	145
Changes in operating assets and liabilities:		
Increase in accounts receivable	(48,631)	(5,183)
Decrease (increase) in accounts receivable—related party	2,490	(1,975)
Increase in prepaid expenses	(994)	(1,133)
Increase in accounts payable and accrued liabilities	53,988	3,089
Settlement of asset retirement obligation	(3,097)	(807)
Net cash provided by operating activities	201,509	73,545
Cash flows from investing activities:		
Deductions to cash held in escrow	8	8
Additions to other property and equipment	(1,759)	(355)
Additions to oil and gas properties	(672,967)	(428,234)
Proceeds from sale of investments	89,120	65,111
Contributions to equity method investments	(39,162)	(21,960)
Distributions from equity method investments	—	901
Net cash used in investing activities	(624,760)	(384,529)
Cash flows from financing activities:		
Principal payments on borrowings	(85)	(73)
Borrowings on line of credit	40,000	—
Debt issuance costs and loan commitment fees	(975)	(686)
Proceeds from issuance of common stock, net of offering costs and exercise of stock options	648	359,040
Net cash provided by financing activities	39,588	358,281
Net (decrease) increase in cash and cash equivalents	(383,663)	47,297
Cash and cash equivalents at beginning of period	458,956	167,088
Cash and cash equivalents at end of period	$75,293	$214,385
Supplemental disclosure of cash flow information:		
Interest payments	$11,738	$12,594
Income tax payments	$16,700	$750
Supplemental disclosure of non-cash transactions:		
Capitalized stock based compensation	$3,066	$1,201

Asset retirement obligation capitalized	$3,613	$1,194
Interest capitalized	$6,245	$5,497
Foreign currency translation loss on investment in Grizzly Oil Sands ULC	$(462)	$(9,680)

See accompanying notes to consolidated financial statements.

Table of Contents

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 (the "SEC"), 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 and six month periods ended June 30, 2014 are not necessarily indicative of the results expected for the full year.

1. ACQUISITIONS

On February 15, 2013, the Company completed an acquisition of approximately 22,000 net acres in the Utica Shale in Eastern Ohio. The purchase price was approximately $220.0 million, subject to certain adjustments. At closing, approximately $33.6 million of the purchase price was placed in escrow pending completion of title review after the closing. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on February 15, 2013. The Company received aggregate net proceeds of approximately $325.8 million from this equity offering. All of the acreage included in these transactions was nonproducing at the time of the applicable transaction and the Company is the operator of all of this acreage, subject to existing development and operating agreements between the parties. These acquisitions excluded the seller's interest in 14 existing wells and 16 proposed future wells together with certain acreage surrounding these wells.

In February 2014, the Company agreed to acquire additional oil and natural gas properties consisting of approximately 8,000 net acres from Rhino Exploration LLC ("Rhino"), as well as its interest in all of the producing wells, in the Utica Shale of Eastern Ohio from Rhino, for a gross purchase price of approximately $184.0 million (the "Rhino Acquisition"), of which the Company closed on approximately $179.0 million ($177.4 million net of purchase price adjustments) on March 20, 2014. The remainder of the acquisition remains pending. The Company recognized $3.1 million of net revenues and $0.4 million of lease operating expenses as a result of the Rhino Acquisition from the closing date of March 20, 2014 through June 30, 2014, which is included in the accompanying consolidated statements of operations.

The Rhino Acquisition qualified as a business combination for accounting purposes and, as such, the Company estimated the fair value of the acquired properties as of the March 20, 2014 acquisition date. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See "Note 10 - Fair Value Measurements" for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the Rhino Acquisition for these properties approximated the fair value that would be paid by a typical market participant. As a result, no goodwill or bargain purchase gain was recognized in conjunction with the purchase.

The following table summarizes the consideration paid in the Rhino Acquisition to acquire the properties and the fair value amounts of the assets acquired as of March 20, 2014. Both the consideration paid and the fair value assigned to the assets is preliminary and subject to adjustment upon final closing.

7

Table of Contents

	(in thousands)
Consideration paid	
Cash, net of purchase price adjustments	$177,444
Fair value of identifiable assets acquired	
Oil and natural gas properties	
Proved	$32,005
Unproved	6,263
Unevaluated	139,176
Fair value of net identifiable assets acquired	$177,444

2. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of June 30, 2014 and December 31, 2013 are as follows:

	June 30, 2014	December 31, 2013
	(In thousands)	
Oil and natural gas properties	$3,201,529	$2,477,178
Office furniture and fixtures	7,317	6,093
Building	4,876	4,626
Land	412	412
Total property and equipment	3,214,134	2,488,309
Accumulated depletion, depreciation, amortization and impairment	(897,553)	(784,717)
Property and equipment, net	$2,316,581	$1,703,592

Included in oil and natural gas properties at June 30, 2014 is the cumulative capitalization of $60.7 million 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 $6.9 million and $13.2 million for the three and six months ended June 30, 2014, respectively, and $3.2 million and $6.1 million for the three and six months ended June 30, 2013, respectively.

The following table summarizes the Company’s non-producing properties excluded from amortization by area at June 30, 2014:

	June 30, 2014
	(In thousands)
Colorado	$5,933
Bakken	295
Southern Louisiana	636
Ohio	1,180,728
Other	45
	$1,187,637

At December 31, 2013, approximately $950.6 million of non-producing leasehold costs was not subject to amortization.

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.

8

Table of Contents

A reconciliation of the Company's asset retirement obligation for the six months ended June 30, 2014 and 2013 is as follows:

	June 30, 2014	June 30, 2013
	(In thousands)	
Asset retirement obligation, beginning of period	$15,083	$13,275
Liabilities incurred	3,613	1,194
Liabilities settled	(3,097)	(807)
Accretion expense	377	349
Asset retirement obligation as of end of period	15,976	14,011
Less current portion	795	780
Asset retirement obligation, long-term	$15,181	$13,231

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 natural gas interests in the Permian Basin (the "Contribution"). The Contribution was completed on October 11, 2012. At the closing of the Contribution, Diamondback issued to the Company (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to the Company at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of Diamondback O&G LLC, formerly Windsor Permian LLC ("Diamondback O&G"), as of the date of the Contribution. In January 2013, the Company received an additional payment from Diamondback of approximately $18.6 million as a result of this post-closing adjustment. Diamondback O&G is a wholly-owned subsidiary of Diamondback. 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.

Immediately upon completion of the Contribution, the Company owned a 35% equity interest in Diamondback, rather than leasehold interests in the Company's Permian Basin acreage. Upon completion of the Diamondback IPO in October 2012, Gulfport owned approximately 21.4% of Diamondback's outstanding common stock. As of June 30, 2014, Gulfport owned 2,379,500 shares representing approximately 4.7% of Diamondback's outstanding common stock. Following the Contribution, the Company has accounted for its interest in Diamondback as an equity investment. See Note 3, "Equity Investments - Diamondback Energy, Inc."

Table of Contents

3. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of June 30, 2014 and December 31, 2013:

		Carrying Value		(Income) loss from equity method investments			
	Approximate Ownership %	June 30, 2014	December 31, 2013	Three months ended June 30, 2014	2013	Six months ended June 30, 2014	2013
		(In thousands)					
Investment in Tatex Thailand II, LLC	23.5 %	$—	$ —	$—	$(205)	$—	$(205)
Investment in Tatex Thailand III, LLC	17.9 %	12,238	10,774	121	75	170	93
Investment in Grizzly Oil Sands ULC	24.9999 %	203,351	191,473	2,228	731	4,229	1,263
Investment in Bison Drilling and Field Services LLC	40.0 %	25,777	12,318	(329)	171	1,604	23
Investment in Muskie Proppant LLC	25.0 %	8,111	7,544	(101)	375	433	816
Investment in Timber Wolf Terminals LLC	50.0 %	1,001	1,001	—	—	—	8
Investment in Windsor Midstream LLC	22.5 %	13,230	10,632	(35)	(474)	(203)	(858)
Investment in Stingray Pressure Pumping LLC	50.0 %	17,769	19,624	1,630	319	2,143	(384)
Investment in Stingray Cementing LLC	50.0 %	2,842	3,291	106	47	201	69
Investment in Blackhawk Midstream LLC	50.0 %	—	—	—	83	(84,787)	122
Investment in Stingray Logistics LLC	50.0 %	1,060	903	(238)	28	(157)	54
Investment in Diamondback Energy, Inc.	4.7 %	211,300	178,708	(72,945)	(51,361)	(121,712)	(112,457)
Investment in Stingray Energy Services LLC	50.0 %	4,757	3,800	(6)	103	35	138
		$501,436	$ 440,068	$(69,569)	$(50,108)	$(198,044)	$(111,318)

The tables below summarize financial information for the Company's equity investments as of June 30, 2014 and December 31, 2013.

Summarized balance sheet information:

	June 30, 2014	December 31, 2013
	(In thousands)	
Current assets	$222,766	$146,075
Noncurrent assets	$3,136,770	$2,567,225
Current liabilities	$310,689	$233,726
Noncurrent liabilities	$741,267	$664,848

Summarized results of operations:

10

Table of Contents

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Gross revenue	$220,013	$81,496	$378,294	$138,434
Net income (loss)	$26,099	$(5,119)	$207,604	$15,508

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC (“Tatex”). 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 approximately 243,000 acres which includes the Phu Horm Field.

Tatex Thailand III, LLC

The Company has an ownership interest in Tatex Thailand III, LLC ("Tatex III"). Tatex III owns a concession covering approximately 245,000 acres in Southeast Asia. During the six months ended June 30, 2014, the Company paid $1.6 million in cash calls related to Tatex III.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns an interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. ("Oil Sands"). As of June 30, 2014, Grizzly had approximately 830,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. During the six months ended June 30, 2014, Gulfport paid $16.6 million in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by $6.8 million for the three months ended June 30, 2014 as a result of a foreign currency translation gain and decreased by $0.5 million for the six months ended June 30, 2014 as a result of a foreign currency translation loss. The Company's investment in Grizzly was decreased by $6.1 million and $9.7 million as a result of a foreign currency translation loss for the three and six months ended June 30, 2013, respectively.

Bison Drilling and Field Services LLC

During 2011, the Company invested in Bison Drilling and Field Services LLC (“Bison”). Bison owns and operates drilling rigs. During the six months ended June 30, 2014, Gulfport paid $15.1 million in cash calls to Bison.

Muskie Proppant LLC

During 2011, the Company invested in Muskie Proppant LLC (“Muskie”), formerly known as Muskie Holdings LLC. Muskie processes and sells sand for use in hydraulic fracturing by the oil and natural gas industry and holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. During the six months ended June 30, 2014, Gulfport paid $1.0 million in cash calls to Muskie.

The Company entered into a loan agreement with Muskie effective July 1, 2013, under which it loaned Muskie $0.9 million. Interest accrues at the prime rate plus 2.5% and the loan had a maturity date of July 31, 2014. Subsequent to June 30, 2014, an amendment was made to the loan agreement which changed the maturity date of the loan to July, 31 2015. At June 30, 2014, the outstanding balance on the loan is included in notes receivable-related party on the accompanying consolidated balance sheets.

Timber Wolf Terminals LLC

During 2012, the Company invested in Timber Wolf Terminals LLC (“Timber Wolf”). The Company's initial investment during 2012 was $1.0 million. Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. During the six months ended June 30, 2014, Gulfport did not pay any cash calls related to Timber Wolf.

Windsor Midstream LLC

Table of Contents

During 2012, the Company purchased an ownership interest in Windsor Midstream LLC (“Midstream”). Midstream owns a 28.4% interest in Coronado Midstream LLC, a gas processing plant in West Texas, formerly known as MidMar Gas LLC. During the six months ended June 30, 2014, Gulfport paid $2.4 million in cash calls to Midstream.

Stingray Pressure Pumping LLC

During 2012, the Company invested in Stingray Pressure Pumping LLC ("Stingray Pressure"). Stingray Pressure provides well completion services. During the six months ended June 30, 2014, the Company paid $2.5 million in cash calls related to Stingray Pressure. The income from equity method investments presented in the table above reflects any intercompany profit eliminations.

Stingray Cementing LLC

During 2012, the Company invested in Stingray Cementing LLC ("Stingray Cementing"). Stingray Cementing provides well cementing services. During the six months ended June 30, 2014, the Company did not pay any cash calls related to Stingray Cementing. The income from equity method investments presented in the table above reflects any intercompany profit eliminations.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC ("Blackhawk"). Blackhawk coordinates gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. On January 28, 2014, Blackhawk closed on the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of $190.0 million, of which $14.3 million was placed in escrow. Gulfport received $84.8 million in net proceeds from this transaction, which is included in income from equity method investments in the accompanying consolidated statements of operations.

Stingray Logistics LLC

During 2012, the Company invested in Stingray Logistics LLC ("Stingray Logistics"). Stingray Logistics provides well services. During the six months ended June 30, 2014, the Company did not pay any cash calls.

Diamondback Energy, Inc.

As noted above in Note 2, on October 11, 2012, following the closing of the Diamondback IPO, the Company owned 7,914,036 shares of Diamondback's outstanding common stock for an initial investment in Diamondback valued at $138.5 million. In June 2014, the Company sold 1,000,000 shares of its Diamondback common stock and received net proceeds of approximately $89.1 million. In June and November of 2013, the Company sold 2,234,536 and 2,300,000 shares of its Diamondback common stock, respectively, and received aggregate net proceeds of approximately $192.7 million. As of June 30, 2014, the Company owned 2,379,500 shares representing approximately 4.7% of Diamondback's outstanding common stock.

The Company accounts for its interest in Diamondback as an equity method investment and has elected the fair value option of accounting for this investment. Although the Company's ownership in Diamondback was below 20% at June 30, 2014, and it no longer has the right to designate a director nominee to serve on Diamondback's Board, the Company's initial nominee still serves as a member of Diamondback's Board. As the Company continues to have influence through this board seat, the Company continues to account for its investment in Diamondback as an equity method investment. The Company valued its investment in Diamondback using the quoted closing market price of Diamondback's stock on June 30, 2014 of $88.80 per share multiplied by the number of outstanding shares of Diamondback's stock held by the Company. The Company recognized an aggregate gain of approximately $72.9 million and $121.7 million on its investment in Diamondback for the three and six months ended June 30, 2014, respectively, and $51.4 million and $112.5 million on its investment in Diamondback for three and six months ended June 30, 2013, respectively, which is included in income from equity method investments in the consolidated statements of operations.

Stingray Energy Services LLC

Table of Contents

During 2013, the Company invested in Stingray Energy Services LLC ("Stingray Energy") at a cost of $2.9 million. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. During the six months ended June 30, 2014, the Company did not pay any cash calls to Stingray Energy. The income from equity method investments presented in the table above reflects any intercompany profit eliminations.

4. OTHER ASSETS

Other assets consist of the following as of June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(In thousands)	
Plugging and abandonment escrow account on the WCBB properties (Note 8)	$3,097	$3,105
Certificates of Deposit securing letter of credit	275	275
Prepaid drilling costs	510	526
Loan commitment fees	9,513	9,341
Derivative receivable	4,493	4,493
Deposits	34	34
Other	63	77
	$17,985	$17,851

5. LONG-TERM DEBT

Long-term debt consisted of the following items as of June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(In thousands)	
Revolving credit agreement (1)	$40,000	$—
Building loans (2)	1,910	1,995
7.75% senior unsecured notes due 2020 (3)	300,000	300,000
Unamortized original issue (discount) premium, net (4)	(2,649)	(2,808)
Less: current maturities of long term debt	(163)	(159)
Debt reflected as long term	$339,098	$299,028

The Company capitalized approximately $3.9 million and $6.2 million in interest expense to oil and natural gas properties during the three and six months ended June 30, 2014, respectively. The Company capitalized approximately $2.9 million and $5.5 million in interest expense to oil and natural gas properties during the three and six months ended June 30, 2013, respectively.

(1) On December 27, 2013, the Company entered into an Amended and Restated Credit Agreement with The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and other lenders (The "Amended and Restated Credit Agreement") that provides for a maximum facility amount of $1.5 billion. The Amended and Restated Credit Agreement matures on June 6, 2018. The Company’s wholly-owned subsidiaries have guaranteed the obligations of the Company under the Amended and Restated Credit Agreement.

On April 23, 2014, the Company entered into a first amendment to the Amended and Restated Credit Agreement. The first amendment increased the letter of credit sublimit from $20.0 million to $70.0 million and provided for an increase in the borrowing base availability from $150.0 million to $275.0 million. The first amendment also made certain changes to the lenders and their respective lending commitments thereunder. As of June 30, 2014, the Company had $40.0 million of borrowings outstanding under the Amended and Restated Credit Agreement. At June 30, 2014, the total availability for future borrowings under the Amended and Restated Credit Agreement, after giving effect to an aggregate of $36.7 million of letters of credit, was $198.3 million.

Advances under the Amended and Restated Credit Agreement may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (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 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars. At June 30, 2014, amounts borrowed under the revolving credit facility bore interest at the eurodollar rate of 1.66%.

The Amended and Restated 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 affiliates.

The negative covenants are subject to certain exceptions as specified in the Amended and Restated Credit Agreement. The Amended and Restated Credit Agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants:

(i) 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 offerings, 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

(ii) 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, 2014.

(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 matures in February 2016 and bears interest at the rate of 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.

(3) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of senior unsecured notes due 2020 (the "October Notes") to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain

14

Table of Contents

non-U.S. persons in accordance with Regulation S under the Securities Act (the "October Notes Offering") under an indenture among the Company, its subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee (the "senior note indenture"). On December 21, 2012, the Company issued an additional $50.0 million in aggregate principal amount of senior unsecured notes due 2020 (the "December Notes") to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act ("the December Notes Offering"). The December Notes were issued as additional securities under the senior note indenture. The October Notes Offering and the December Notes Offering are collectively referred to as the "Notes Offerings". The Company used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under its revolving credit facility. The Company used the remaining net proceeds of October Notes Offering and the net proceeds of the December Notes Offering for general corporate purposes, which included funding a portion of its 2013 capital development plan.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.75% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The Notes are the Company's senior unsecured obligations and rank equally in the right of payment with all of the Company's other senior indebtedness and senior in right of payment to any future subordinated indebtedness. All of the Company's existing and future restricted subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt guarantee the Notes; provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries. The Company may redeem some or all of the Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, the Company may redeem the Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, the Company may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Notes initially issued remains outstanding immediately after such redemption.

(4) The October Notes were issued at a price of 98.534% resulting in a gross discount of $3.7 million and an effective rate of 8.000%. The December Notes were issued at a price of 101.000% resulting in a gross premium of $0.5 million and an effective rate of 7.531%. The premium and discount are being amortized using the effective interest method.

6. STOCK-BASED COMPENSATION

During the three and six months ended June 30, 2014, the Company’s stock-based compensation cost was $3.4 million and $7.7 million, respectively, of which the Company capitalized $1.3 million and $3.1 million, respectively, relating to its exploration and development efforts. During the three and six months ended June 30, 2013, the Company's stock-based compensation cost was $1.5 million and $3.0 million, respectively, of which the Company capitalized $0.6 million and $1.2 million, respectively, relating to its exploration and development efforts.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. 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 the 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 2013 Restated Stock Incentive Plan (which amended and restated the 2005 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, 2014 and 2013.

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, 2014 is presented below:

15

Table of Contents

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at December 31, 2013	210,241	$3.50	1.07	$12,538
Granted	—	—		
Exercised	(192,908)	3.36		12,310
Forfeited/expired	—	—		
Options outstanding at June 30, 2014	17,333	$5.01	0.74	$1,002
Options exercisable at June 30, 2014	17,333	$5.01	0.74	$1,002

The following table summarizes information about the stock options outstanding at June 30, 2014:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$3.36	12,333	0.56	12,333
$9.07	5,000	1.19	5,000
	17,333		17,333

The following table summarizes restricted stock activity for the six months ended June 30, 2014:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2013	463,637	$44.80
Granted	198,293	67.75
Vested	(124,526)	46.07
Forfeited	(30,469)	63.08
Unvested shares as of June 30, 2014	506,935	$53.36

Unrecognized compensation expense as of June 30, 2014 related to outstanding stock options and restricted shares was $23.2 million. The expense is expected to be recognized over a weighted average period of 1.66 years.

Table of Contents

7. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net income per common share are presented in the tables below:

	Three months ended June 30,					
	2014			2013		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income	$47,852	85,448,678	$0.56	$43,828	77,428,605	$0.57
Effect of dilutive securities:						
Stock options and awards	—	357,218		—	478,182	
Diluted:						
Net income	$47,852	85,805,896	$0.56	$43,828	77,906,787	$0.56

	Six months ended June 30,					
	2014			2013		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)					
Basic:						
Net income	$130,410	85,354,566	$1.53	$88,387	75,142,113	$1.18
Effect of dilutive securities						
Stock options and awards	—	412,113		—	457,495	
Diluted:						
Net income	$130,410	85,766,679	$1.52	$88,387	75,599,608	$1.17

There were no potential shares of common stock that were considered anti-dilutive for the three and six months ended June 30, 2014 and 2013.

Table of Contents

8. COMMITMENTS

Plugging and Abandonment Funds

In connection with the Company's acquisition in 1997 of the remaining 50% interest in its 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 the Company's 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, 2014, the plugging and abandonment trust totaled approximately $3.1 million. At June 30, 2014, the Company had plugged 378 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Employment Agreements

Effective November 1, 2012, the Company entered into an employment agreement with each of its three executive officers, each with an initial three-year term expiring on November 1, 2015 subject to automatic one-year extensions unless terminated by either party to the agreement at least 90 days prior to the end of the then current term. These agreements provided for minimum salary and bonus levels, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits.

Effective February 15, 2014, Gulfport's former Chief Executive Officer, James D. Palm, retired and his employment agreement with the company terminated. The Company entered into a separation agreement with Mr. Palm, under which agreement certain benefits are provided to, and obligations imposed on, Mr. Palm. Gulfport's former Chairman, Mr. Liddell, resigned effective June 2013 at which date his employment agreement with Gulfport terminated. At that same date, the Company entered into a consulting agreement with Mr. Liddell. The minimum commitment under Mr. Liddell's consulting agreement at June 30, 2014 was approximately $0.7 million and the minimum commitment under Mr. Palm's separation agreement at June 30, 2014 was approximately $0.6 million.

On April 22, 2014, the Board of Directors appointed Michael G. Moore as Chief Executive Officer of the Company. The Company and Mr. Moore entered into an amended and restated employment agreement. The agreement has a three-year term commencing effective April 22, 2014. This agreement provides, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits. The aggregate minimum commitment for future salary at June 30, 2014 under the April 22, 2014 amended and restated employment agreement was approximately $1.1 million.

Operating Leases

The Company leases office facilities under non-cancellable operating leases exceeding one year. Future minimum lease commitments under these leases at June 30, 2014 are as follows:

	(In thousands)
Remaining 2014	$268
2015	494
2016	426
2017	398
2018	—
Total	$1,586

Litigation

Gulfport has previously provided disclosure regarding three separate lawsuits filed by the Louisiana Department of Revenue ("LDR") disputing Gulfport's severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2010. In June 2014, Gulfport and LDR entered into a settlement agreement under which Gulfport paid $6.0 million, which is included in litigation settlement in the accompanying consolidated statements of

18

operations, and LDR released all claims for severance taxes for tax years 2005 to 2010 and dismissed all three lawsuits with prejudice.

Gulfport has previously provided disclosure regarding a lawsuit filed entitled Reeds et al. v. BP American Production Company et al., in the 38th Judicial District Court of Louisiana, Case No. 10-18714, filed against 15 oil and gas defendants on July 30, 2010 by six individuals and one limited liability company in Cameron Parish Louisiana for surface contamination in areas where Gulfport and other defendants operated. In 2014, Gulfport and the plaintiffs have had settlement discussions focused on Gulfport's payment of approximately $18.0 million plus the cost of a plan of remediation to be approved by the Court and the Louisiana Department of Natural Resources. The settlement has not yet been finalized and there can be no assurance that a settlement will be reached on these or any other terms. The Company has accrued the $18.0 million proposed settlement as of June 30, 2014, which is included in litigation settlement in the accompanying consolidated statements of operations. The case was set for trial in July 2014, but plaintiffs’ counsel filed a motion to continue the trial, which was granted, so the parties could work on settlement of the matter. There is no new trial date set at this time, and the lawsuit is not being actively litigated.

Due to the current stage of the Reeds lawsuit and settlement discussions, the outcome is uncertain and management cannot determine the amount of loss that may result. An adverse decision in the matter 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 lawsuits related to its business. The resolution of these matters is not expected to have a material adverse effect on the Company's financial condition or results of operations in future periods.

9. HEDGING ACTIVITIES

Oil Price Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in oil and natural gas prices, which are subject to significant and often volatile fluctuation, by entering into fixed price swaps. These contracts allow the Company to predict with greater certainty the effective oil and natural gas 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 and natural gas derivative instruments as cash flow hedges for accounting purposes under FASB ASC 815 and related pronouncements. All derivative contracts are marked to market each quarter end and are included in the accompanying consolidated balance sheets as derivative assets and liabilities.

During 2013 and 2014, the Company entered into fixed price swap and swaption contracts for 2013 through 2016 with four financial institutions. The Company’s fixed price swap contracts are tied to the commodity prices on the International Petroleum Exchange (“IPE”) and NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on the IPE for Brent Crude for oil and on the NYMEX Henry Hub for natural gas. At June 30, 2014, the Company had the following fixed price swaps in place:

	Daily Volume (Bbls/day)	Weighted Average Price
July - December 2014	2,000	$101.50
	Daily Volume (MMBtu/day)	Weighted Average Price
July - December 2014	155,000	$4.07
January - December 2015	175,000	$4.08
January - March 2016	105,000	$4.04
April 2016	95,000	$4.04

At June 30, 2014 the fair value of derivative assets and liabilities related to the fixed price swaps and swaptions was as follows:

	(In thousands)
Long-term derivative instruments - asset	$784
Short-term derivative instruments - liability	$24,532
Long-term derivative instruments - liability	$5,487

All fixed price swaps and swaptions have been executed in connection with the Company's oil and natural gas 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 and gas sales in the period for which the underlying production was hedged.

Table of Contents

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 (loss) until the hedged item is recognized in earnings. The Company had no cash flow hedges in place for the six months ending June 30, 2014, as all fixed price swaps and swaptions were deemed ineffective at their inception. Amounts reclassified out of accumulated other comprehensive income (loss) into earnings as a component of oil and condensate sales for the three and six months ended June 30, 2014 and 2013 are presented below.

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(In thousands)		(In thousands)	
Reduction to oil and condensate sales	$—	$(1,404)	$—	$(3,201)

At June 30, 2014, no amounts related to fixed price swaps remain in accumulated other comprehensive income (loss). 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 $2.2 million and a loss of $6.4 million related to hedge ineffectiveness for the three and six months ended June 30, 2014, respectively, which is included in oil and condensate and gas sales in the consolidated statements of operations. The Company recognized a gain of $5.5 million and $5.4 million related to hedge ineffectiveness for the three and six months ended June 30, 2013, respectively, which is included in oil and condensate sales in the consolidated statements of operations.

10. FAIR VALUE MEASUREMENTS

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

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

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

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

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

The following tables summarize the Company’s financial and non-financial liabilities by FASB ASC 820 valuation level as of June 30, 2014:

	June 30, 2014		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Fixed price swaps	$—	$784	$—
Equity investment in Diamondback	211,300	—	—
Liabilities:			
Fixed price swaps and swaptions	$—	$30,019	$—

The estimated fair value of the Company’s fixed price swap contracts and swaptions were based upon forward commodity prices based on quoted market prices, adjusted for differentials, and for the Company's swaptions, market implied

20

volatilities of the underlying commodity were also evaluated. See Note 9 for further discussion of the Company's hedging activities. The estimated fair value of the Company's equity investment in Diamondback was based upon the public closing share price of Diamondback's common stock as of June 30, 2014.

The estimated fair values of proved oil and gas properties assumed in business combinations are based on a discounted cash flow model and market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk-adjusted discount rates. The estimated fair values of unevaluated oil and gas properties was based on geological studies, historical well performance, location and applicable mineral lease terms. Based on the unobservable nature of certain of the inputs the estimated fair value of the oil and gas properties assumed is deemed to use Level 3 inputs. See Note 1 for further discussion of the Company's acquisitions.

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 2 for further discussion of the Company’s asset retirement obligations. Asset retirement obligations incurred during the six months ended June 30, 2014 were approximately $3.6 million.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the building loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities.

At June 30, 2014, the carrying value of the outstanding debt represented by the Notes was $297.4 million, including the remaining unamortized discount of approximately $3.0 million related to the October Notes and the remaining unamortized premium of approximately $0.4 million related to the December Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $325.7 million at June 30, 2014.

The fair value of the derivative instruments is computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis differentials, and for the Company's swaptions, market implied volatilities of the underlying commodity are also evaluated. Forward market prices for oil and natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility.

12. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012 and December 21, 2012, the Company issued an aggregate of $300.0 million of its 7.75% Senior Notes (the "Notes"). The Notes are guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt (the "Guarantors"). The Notes are not guaranteed by Grizzly Holdings, Inc., (the "Non-Guarantor"). The Guarantors are 100% owned by Gulfport (the "Parent"), and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive income (loss) and statements of cash flows are provided for the Parent, the Guarantors and the Non-Guarantor and include the consolidating adjustments and eliminations necessary to arrive at the information for the Company on a condensed consolidated basis. The information has been presented using the equity method of accounting for the Parent's ownership of the Guarantors and the Non-Guarantor.

21

Table of Contents

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$72,921	$2,371	$ 1	$—	$75,293
Accounts receivable - oil and gas	102,136	5,319	—	—	107,455
Accounts receivable - related parties	127	—	—	—	127
Accounts receivable - intercompany	24,774	27	—	(24,801)	—
Prepaid expenses and other current assets	3,575	—	—	—	3,575
Deferred tax asset	7,661	—	—	—	7,661
Note receivable - related party	875	—	—	—	875
Total current assets	212,069	7,717	1	(24,801)	194,986
Property and equipment:					
Oil and natural gas properties, full-cost accounting	3,191,073	11,029	—	(573)	3,201,529
Other property and equipment	12,575	30	—	—	12,605
Accumulated depletion, depreciation, amortization and impairment	(897,530)	(23)	—	—	(897,553)
Property and equipment, net	2,306,118	11,036	—	(573)	2,316,581
Other assets:					
Equity investments and investments in subsidiaries	494,342	—	203,351	(196,257)	501,436
Derivative instruments	784	—	—	—	784
Other assets	17,985	—	—	—	17,985
Total other assets	513,111	—	203,351	(196,257)	520,205
Total assets	$3,031,298	$18,753	$ 203,352	$(221,631)	$3,031,772
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$286,984	$474	$ —	$—	$287,458
Accounts payable - intercompany	—	24,696	105	(24,801)	—
Asset retirement obligation - current	795	—	—	—	795
Short-term derivative instruments	24,532	—	—	—	24,532
Current maturities of long-term debt	163	—	—	—	163
Total current liabilities	312,474	25,170	105	(24,801)	312,948
Long-term derivative instrument	5,487	—	—	—	5,487
Asset retirement obligation - long-term	15,181	—	—	—	15,181
Deferred tax liability	170,559	—	—	—	170,559
Long-term debt, net of current maturities	339,098	—	—	—	339,098
Total liabilities	842,799	25,170	105	(24,801)	843,273
Stockholders' equity:					
Common stock	854	—	—	—	854
Paid-in capital	1,821,368	322	224,849	(225,171)	1,821,368
	(10,243)	—	(10,243)	10,243	(10,243)

Accumulated other comprehensive income (loss)					
Retained earnings (accumulated deficit)	376,520	(6,739)	(11,359)	18,098	376,520
Total stockholders' equity	2,188,499	(6,417)	203,247	(196,830)	2,188,499
Total liabilities and stockholders' equity	$3,031,298	$18,753	$203,352	$(221,631)	$3,031,772

22

Table of Contents

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$451,431	$7,525	$—	$—	$458,956
Accounts receivable - oil and gas	58,662	162	—	—	58,824
Accounts receivable - related parties	2,617	—	—	—	2,617
Accounts receivable - intercompany	21,379	27	—	(21,406)	—
Prepaid expenses and other current assets	2,581	—	—	—	2,581
Deferred tax asset	6,927	—	—	—	6,927
Short-term derivative instruments	324	—	—	—	324
Note receivable - related party	875	—	—	—	875
Total current assets	544,796	7,714	—	(21,406)	531,104
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	2,470,411	7,340	—	(573)	2,477,178
Other property and equipment	11,102	29	—	—	11,131
Accumulated depletion, depreciation, amortization and impairment	(784,695)	(22)	—	—	(784,717)
Property and equipment, net	1,696,818	7,347	—	(573)	1,703,592
Other assets:					
Equity investments and investments in subsidiaries	432,727	—	191,473	(184,132)	440,068
Derivative instruments	521	—	—	—	521
Other assets	17,851	—	—	—	17,851
Total other assets	451,099	—	191,473	(184,132)	458,440
Total assets	$2,692,713	$15,061	$ 191,473	$(206,111)	$2,693,136
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$190,284	$423	$—	$—	$190,707
Accounts payable - intercompany	—	21,296	110	(21,406)	—
Asset retirement obligation - current	795	—	—	—	795
Short-term derivative instruments	12,280	—	—	—	12,280
Current maturities of long-term debt	159	—	—	—	159
Total current liabilities	203,518	21,719	110	(21,406)	203,941
Long-term derivative instrument	11,366	—	—	—	11,366
Asset retirement obligation - long-term	14,288	—	—	—	14,288
Deferred tax liability	114,275	—	—	—	114,275
Long-term debt, net of current maturities	299,028	—	—	—	299,028
Total liabilities	642,475	21,719	110	(21,406)	642,898
Stockholders' equity:					

Common stock	851	—	—	—	851
Paid-in capital	1,813,058	322	208,277	(208,599)	1,813,058
Accumulated other comprehensive income (loss)	(9,781)	—	(9,781)	9,781	(9,781)
Retained earnings (accumulated deficit)	246,110	(6,980)	(7,133)	14,113	246,110
Total stockholders' equity	2,050,238	(6,658)	191,363	(184,705)	2,050,238
Total liabilities and stockholders' equity	$2,692,713	$15,061	$ 191,473	$(206,111)	$2,693,136

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$114,014	$722	$ —	$—	$114,736
Costs and expenses:					
Lease operating expenses	12,457	223	—	—	12,680
Production taxes	6,529	72	—	—	6,601
Midstream processing and marketing	10,758	22	—	—	10,780
Depreciation, depletion, and amortization	55,993	1	—	—	55,994
General and administrative	10,346	35	1	—	10,382
Accretion expense	189	—	—	—	189
	96,272	353	1	—	96,626
INCOME (LOSS) FROM OPERATIONS	17,742	369	(1)	—	18,110
OTHER (INCOME) EXPENSE:					
Interest expense	2,402	—	—	—	2,402
Interest income	(36)	—	—	—	(36)
Litigation settlement	6,000	—	—	—	6,000
(Income) loss from equity method investments and investments in subsidiaries	(69,937)	—	2,228	(1,860)	(69,569)
	(61,571)	—	2,228	(1,860)	(61,203)
INCOME (LOSS) BEFORE INCOME TAXES	79,313	369	(2,229)	1,860	79,313
INCOME TAX EXPENSE	31,461	—	—	—	31,461
NET INCOME (LOSS)	$47,852	$369	$ (2,229)	$1,860	$47,852

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Three months ended June 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$70,033	$401	$—	$—	$70,434
Costs and expenses:					
Lease operating expenses	5,714	164	—	—	5,878
Production taxes	6,419	21	—	—	6,440
Midstream processing and marketing	1,897	4	—	—	1,901
Depreciation, depletion, and amortization	28,539	1	—	—	28,540
General and administrative	4,859	38	3	—	4,900
Accretion expense	174	—	—	—	174
Loss on sale of assets	145	—	—	—	145
	47,747	228	3	—	47,978
INCOME (LOSS) FROM OPERATIONS	22,286	173	(3)	—	22,456
OTHER (INCOME) EXPENSE:					
Interest expense	3,284	—	—	—	3,284
Interest income	(62)	—	—	—	(62)
(Income) loss from equity method investments and investments in subsidiaries	(50,278)	—	730	(560)	(50,108)
	(47,056)	—	730	(560)	(46,886)
INCOME (LOSS) BEFORE INCOME TAXES	69,342	173	(733)	560	69,342
INCOME TAX EXPENSE	25,514	—	—	—	25,514
NET INCOME (LOSS)	$43,828	$173	$ (733)	$560	$43,828

25

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Six months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$231,864	$901	$ —	$—	$232,765
Costs and expenses:					
Lease operating expenses	23,838	471	—	—	24,309
Production taxes	13,466	92	—	—	13,558
Midstream processing and marketing	18,515	34	—	—	18,549
Depreciation, depletion, and amortization	112,870	1	—	—	112,871
General and administrative	19,834	62	(3)	—	19,893
Accretion expense	377	—	—	—	377
Gain on sale of assets	(11)	—	—	—	(11)
	188,889	660	(3)	—	189,546
INCOME FROM OPERATIONS	42,975	241	3	—	43,219
OTHER (INCOME) EXPENSE:					
Interest expense	6,287	—	—	—	6,287
Interest income	(142)	—	—	—	(142)
Litigation settlement	24,000	—	—	—	24,000
(Income) loss from equity method investments and investments in subsidiaries	(198,288)	—	4,229	(3,985)	(198,044)
	(168,143)	—	4,229	(3,985)	(167,899)
INCOME (LOSS) BEFORE INCOME TAXES	211,118	241	(4,226)	3,985	211,118
INCOME TAX EXPENSE	80,708	—	—	—	80,708
NET INCOME (LOSS)	$130,410	$241	$ (4,226)	$3,985	$130,410

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Six months ended June 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$124,695	$739	$—	$—	$125,434
Costs and expenses:					
Lease operating expenses	10,712	338	—	—	11,050
Production taxes	13,267	43	—	—	13,310
Midstream processing and marketing	2,310	8	—	—	2,318
Depreciation, depletion, and amortization	51,122	1	—	—	51,123
General and administrative	9,237	72	3	—	9,312
Accretion expense	349	—	—	—	349
Loss on sale of assets	572	—	—	—	572
	87,569	462	3	—	88,034
INCOME (LOSS) FROM OPERATIONS	37,126	277	(3)	—	37,400
OTHER (INCOME) EXPENSE:					
Interest expense	6,763	—	—	—	6,763
Interest income	(141)	—	—	—	(141)
(Income) loss from equity method investments and investments in subsidiaries	(111,592)	—	1,262	(988)	(111,318)
	(104,970)	—	1,262	(988)	(104,696)
INCOME (LOSS) BEFORE INCOME TAXES	142,096	277	(1,265)	988	142,096
INCOME TAX EXPENSE	53,709	—	—	—	53,709
NET INCOME (LOSS)	$88,387	$277	$(1,265)	$988	$88,387

27

Table of Contents

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Amounts in thousands)

	Three months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$47,852	$369	$ (2,229)	$1,860	$47,852
Foreign currency translation adjustment	6,816	—	6,816	(6,816)	6,816
Other comprehensive income (loss)	6,816	—	6,816	(6,816)	6,816
Comprehensive income (loss)	$54,668	$369	$ 4,587	$(4,956)	$54,668

	Three months ended June 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$43,828	$173	$ (733)	$560	$43,828
Foreign currency translation adjustment	(6,113)	—	(6,113)	6,113	(6,113)
Change in fair value of derivative instruments, net of taxes	356	—	—	—	356
Reclassification of settled contracts, net of taxes	1,404	—	—	—	1,404
Other comprehensive income (loss)	(4,353)	—	(6,113)	6,113	(4,353)
Comprehensive income (loss)	$39,475	$173	$ (6,846)	$6,673	$39,475

	Six months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$130,410	$241	$ (4,226)	$3,985	$130,410
Foreign currency translation adjustment	(462)	—	(462)	462	(462)
Other comprehensive income (loss)	(462)	—	(462)	462	(462)
Comprehensive income (loss)	$129,948	$241	$ (4,688)	$4,447	$129,948

	Six months ended June 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$88,387	$277	$ (1,265)	$988	$88,387
Foreign currency translation adjustment	(9,680)	—	(9,680)	9,680	(9,680)
Change in fair value of derivative instruments, net of taxes	(1,074)	—	—	—	(1,074)
Reclassification of settled contracts, net of taxes	3,201	—	—	—	3,201
Other comprehensive income (loss)	(7,553)	—	(9,680)	9,680	(7,553)
Comprehensive income (loss)	$80,834	$277	$ (10,945)	$10,668	$80,834

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Six months ended June 30, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$203,057	$(1,546)	$ (2)	$—	$201,509
Net cash provided by (used in) investing activities	(621,155)	(3,608)	(16,569)	16,572	(624,760)
Net cash provided by (used in) financing activities	39,588	—	16,572	(16,572)	39,588
Net iecrease in cash and cash equivalents	(378,510)	(5,154)	1	—	(383,663)
Cash and cash equivalents at beginning of period	451,431	7,525	—	—	458,956
Cash and cash equivalents at end of period	$72,921	$2,371	$ 1	$—	$75,293

	Six months ended June 30, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$73,633	$(88)	$ —	$—	$73,545
Net cash provided by (used in) investing activities	(383,817)	(712)	(15,055)	15,055	(384,529)
Net cash provided by (used in) financing activities	358,281	—	15,055	(15,055)	358,281
Net increase (decrease) in cash and cash equivalents	48,097	(800)	—	—	47,297
Cash and cash equivalents at beginning of period	165,293	1,795	—	—	167,088
Cash and cash equivalents at end of period	$213,390	$995	$ —	$—	$214,385

Table of Contents

13. RECENT ACCOUNTING PRONOUNCEMENTS

In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. ASU 2014-08 changes the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. The ASU is effective for annual and interim periods beginning after December 15, 2014, however, early adoption is permitted. The Company early adopted this ASU on a prospective basis beginning with the second quarter of 2014. The adoption did not have a material impact on the Company's consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. The Company is in the process of evaluating the impact on its consolidated financial statements.

Table of Contents

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

The following discussion and analysis should be read in conjunction with the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section and audited consolidated financial statements and related notes 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 natural 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; adverse weather conditions and natural disasters such as hurricanes and other factors, including those listed in the "Risk Factors" section of our most recent Annual Report on Form 10-K, Quarterly Reports on Form 10-Q or any other filings we make with the SEC, 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 focused on the exploration, exploitation, acquisition and production of crude oil, natural gas liquids and natural gas in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale in Eastern Ohio and along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. In addition, we have producing properties in the Niobrara Formation of Northwestern Colorado and the Bakken Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, an equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and natural gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO, and 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.

2014 Operational Highlights

- Oil and natural gas revenues increased 63% to $114.5 million for the three months ended June 30, 2014 from $70.2 million for the three months ended June 30, 2013.
- Production increased 198% to 2,431,955 barrels of oil equivalent ("BOE") for the three months ended June 30, 2014 from 815,300 BOE for the three months ended June 30, 2013.
- During the three months ended June 30, 2014, we spud 37 gross (29 net) wells, participated in an additional 19 gross (2.4 net) wells that were drilled by other operators on our Utica Shale acreage and recompleted 46 gross and net wells. Of our 37 new wells spud at June 30, 2014, nine were completed as producing wells, one was non-productive, 22 were waiting on completion and five were being drilled.

Table of Contents

In March 2014, we acquired approximately 8,000 net acres in the Utica Shale of Eastern Ohio from Rhino Exploration LLC, or Rhino, as well as its interest in producing wells, for a total purchase price of $179.0 million ($177.4 million net of purchase price adjustments). We are the operator of substantially all of this acreage.

2014 Production and Drilling Activity

During the three months ended June 30, 2014, our total net production was 709,484 barrels of oil, 8,972,137 thousand cubic feet, or Mcf, of natural gas, and 9,538,843 gallons of natural gas liquids, or NGLs, for a total of 2,431,955 BOE as compared to 535,182 barrels of oil, 1,414,797 Mcf of natural gas and 1,861,360 gallons of NGLs, or 815,300 BOE, for the three months ended June 30, 2013. Our total net production averaged approximately 26,725 BOE per day during the three months ended June 30, 2014 as compared to 8,959 BOE per day during the same period in 2013. The 198% increase in production is largely the result of the development of our Utica Shale acreage.

Utica Shale. As of August 1, 2014, we had acquired leasehold interests in approximately 184,500 gross (183,500 net) acres in the Utica Shale in Eastern Ohio, including the approximately 8,000 net acres acquired from Rhino during the first quarter of 2014. We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of June 30, 2014, had spud 99 wells, 60 of which had been completed and, as of August 1, 2014 were producing. From January 1, 2014 through August 1, 2014, we spud 47 gross (34 net) wells, of which six were producing, four were waiting on a horizontal rig, 30 were waiting on completion and seven were still being drilled at August 1, 2014. In addition, 19 gross (2.4 net) wells were drilled by other operators on our Utica Shale acreage during the three months ended June 30, 2014.

We have seven rigs under contract on our Utica Shale acreage. We currently intend to drill 85 to 95 gross (68 to 76 net) wells on our Utica Shale acreage in 2014.

Aggregate net production from our Utica Shale acreage during the three months ended June 30, 2014 was approximately 1,930,139 net BOE, or 21,210 BOE per day, 77% of which was from natural gas and 23% of which was from oil and natural gas liquids, or NGLs. During July 2014, our average daily net production from the Utica Shale was approximately 29,088 BOE, 76% of which was from natural gas and 24% of which was from oil and NGLs. The increase in July production was due to increased production as a result of our drilling activity on our Utica Shale acreage.

WCBB. From January 1, 2014 through August 1, 2014, we recompleted 60 wells and spud 17 wells. Of the 17 new wells spud at WCBB, 11 were completed as producing wells, four were non-productive, one was waiting on completion and one was being drilled at August 1, 2014. During 2014, we currently anticipate drilling 22 to 24 wells at our WCBB field.

Aggregate net production from the WCBB field during the three months ended June 30, 2014 was approximately 315,860 BOE, or an average of 3,471 BOE per day, 100% of which was from oil. During July 2014, our average net daily production at WCBB was approximately 3,278 BOE, 100% of which was from oil. The slight decrease in July production is primarily the result of timing of bringing our 2014 drilling program wells online and natural production declines.

East Hackberry Field. From January 1, 2014 through August 1, 2014, we recompleted 33 wells and spud nine wells. Of the nine new wells drilled at East Hackberry, eight were completed as producing wells and one was waiting on completion at August 1, 2014. During 2014, we currently anticipate drilling ten to twelve wells.

Aggregate net production from the East Hackberry field during the three months ended June 30, 2014 was approximately 152,284 BOE, or an average of 1,673 BOE per day, 89% of which was from oil and 11% of which was from natural gas. During July 2014, our average net daily production at East Hackberry was approximately 1,300 BOE, 93% of which was from oil and 7% of which was from natural gas. The decrease in July production is primarily the result of natural production declines.

West Hackberry Field. From January 1, 2014 through August 1, 2014, we recompleted two wells. No new wells were drilled at West Hackberry from January 1, 2014 to August 1, 2014.

Aggregate net production from the West Hackberry field was approximately 15,766 BOE, or an average of 173 BOE per day, 100% of which was from oil. During July 2014, our average net daily production at West Hackberry was

approximately 137 BOE, 92% of which was from oil and 8% of which was from natural gas.
Niobrara Formation. Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Northwestern Colorado and, as of June 30, 2014, we held leases for approximately 6,549 net acres. From January 1, 2014

Table of Contents

through August 1, 2014, there were no wells spud on our Niobrara Formation acreage. Aggregate net production from our Niobrara Formation acreage during the three months ended June 30, 2014 was approximately 4,774 BOE, or an average of 52 BOE per day, 100% of which was from oil. During July 2014, our average net daily production from our Niobrara Formation acreage was approximately 48 BOE, 100% of which was from oil. During 2014, we currently do not anticipate drilling any wells in the Niobrara Formation.

Bakken. As of June 30, 2014, we held approximately 864 net acres in the Bakken Formation of Western North Dakota and Eastern Montana with interests in 18 wells and overriding royalty interests in certain existing and future wells. Aggregate net production from this acreage during the three months ended June 30, 2014 was approximately 12,675 BOE, or an average of 139 BOE per day, of which 91% was from oil, 7% was from natural gas and 2% was from NGLs. During July 2014, our average daily net production from our Bakken Formation acreage was approximately 102 BOE, of which 89% was from oil and 11% was from natural gas.

2014 Updates Regarding Our Equity Investments

Permian Basin. On October 11, 2012, we contributed to Diamondback, prior to the closing of the Diamondback IPO, all of our oil and natural gas interests in the Permian Basin. At the closing of this contribution, Diamondback issued to us (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to us at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of a Diamondback subsidiary as of the date of this contribution. In January 2013, we received an additional payment from Diamondback of $18.6 million as a result of this post-closing adjustment. In June and November of 2013, we sold 2,234,536 and 2,300,000 shares of our Diamondback common stock, respectively, and received aggregate net proceeds of approximately $192.7 million. In June 2014, we sold 1,000,000 shares of our Diamondback common stock and received net proceeds of approximately $89.1 million. As of June 30, 2014, we owned approximately 2,379,500 shares representing approximately 4.7% of Diamondback's outstanding common stock. Our investment in Diamondback is accounted for as an equity method investment.

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. As of June 30, 2014, Grizzly had over 800,000 net acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada and had three oil sands projects in various stages of development. Initiation of steam injection at its first project, Algar Lake Phase 1, commenced in January 2014 and first bitumen production was achieved during the second quarter of 2014. Bitumen production averaged 510 barrels per day in May and June and exited the quarter at approximately 1,200 barrels per day. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. An initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. Grizzly is preparing responses to the first round of supplemental information requests, or SIRs, and expects to deliver replies to the Alberta Energy Regulator, or AER, by mid-August. In the first quarter of 2014, a 2D seismic program covering approximately 83 kilometers, was completed to more fully define the development area over the remaining lease beyond the development application area. At the Thickwood thermal project, a development application for a 12,000 barrel per day oil sands project was filed in the fourth quarter of 2012. Since then, the AER announced it is implementing a policy for future regulatory requirements for reservoir containment in shallow SAGD areas, which impacts the Thickwood application. Further work on advancing the Thickwood application will be delayed pending regulatory resolution of the shallow SAGD issue. Grizzly completed construction of the Windell truck-to-rail terminal, proximate to its May River lease, and began crude oil shipments to the U.S. Gulf Coast in the second quarter of 2014. All of Grizzly’s oil is now being sold into the U.S. Gulf Coast heavy oil market at Natchez, Mississippi, where Grizzly receives Mars based pricing. Grizzly is in discussion with third parties to expand its transloading business. On the U.S. Gulf Coast, Grizzly has completed the design engineering for the Paulina rail-to-barge terminal and filed development permits. Grizzly is working through the permitting process to gain approval to construct the facility. Both of these terminals will be located on the Canadian National Railway’s Company, or CN, main line. Grizzly has entered into a contract with CN that fixes the rate structure for a ten-year period for transportation of bitumen loaded at Windell and shipped to the U.S. Gulf Coast via CN’s rail network.

Thailand. We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field. Our investment is accounted for on the equity method. Tatex II accounts for its investment in APICO using the cost method. Hess Corporation, or Hess, operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTT Exploration and Production Public Company Limited (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

Table of Contents

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 own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Tatex III owns a concession covering approximately 245,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. In October 2013, Tatex III spud the TEW-K well, located to the south of the TEW-E well. The well tested gas at non-commercial rates. During drilling, the well flowed gas with rates as high as 20 MMcf per day of gas; however, no acceptable sustainable rate was established.
Other Investments. In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the first quarter of 2013, we participated in the formation of Stingray Energy Services LLC, or Stingray Energy, with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure Pumping LLC, or Stingray Pressure, Stingray Cementing LLC, or Stingray Cementing, and Stingray Logistics LLC, or Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk Midstream LLC, or Blackhawk, and Timber Wolf Terminals LLC, or Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie Proppant LLC, or Muskie, which is engaged in the processing and sale of hydraulic fracturing grade sand. See Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.
Critical Accounting Policies and Estimates
Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:
Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. 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 prior twelve months, 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 $1.2 billion at June 30, 2014 and $950.6 million at December 31, 2013. 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 prior twelve months of the applicable year beginning with 2009, 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, 2014.

Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.
We account for abandonment and restoration liabilities under FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.
The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.
Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Ryder Scott Company, L.P. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2013 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 the guidelines of the Securities and Exchange Commission, or SEC. 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, 2014, a valuation allowance of $2.6 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized.

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.

Investments—Equity Method. Investments in entities greater than 20% and less than 50% and/or investments in which we have significant influence are accounted for under the equity method. Under the equity method, our share of investees' earnings or loss is recognized in the statement of operations. In accordance with FASB ASC 825, "Financial Instruments," we have elected the fair value option of accounting for our equity method investment in Diamondback's stock. At the end of each reporting period, the quoted closing market price of Diamondback's stock is multiplied by the total shares owned by us and the resulting gain or loss is recognized in (income) loss from equity method investments in the consolidated statements of operations.

We review our investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, we recognize an impairment provision. There was no impairment of equity method investments at June 30, 2014 and December 31, 2013.

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 and natural gas prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of FASB ASC 815, "Derivatives and 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. There were no hedges designated as cash flow hedges during the three months ended June 30, 2014 as all of our current hedges were deemed ineffective at inception.

RESULTS OF OPERATIONS

Comparison of the Three Months Ended June 30, 2014 and 2013

We reported net income of $47.9 million for the three months ended June 30, 2014 as compared to $43.8 million for the three months ended June 30, 2013. This 9% increase in period-to-period net income was due primarily to $72.9 million of income recognized from our equity method investment in Diamondback and a 198% increase in net production to 2,431,955 BOE from 815,300 BOE, partially offset by a 45% decrease in realized BOE prices to $47.08 from $86.10, a $6.8 million increase in lease operating expenses, an $8.9 million increase in midstream transportation, processing and marketing expenses, a $5.5 million increase in general and administrative expenses, an expense of $6.0 million for litigation settlement and a $5.9 million increase in income tax expense for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013.

Oil and Gas Revenues. For the three months ended June 30, 2014, we reported oil and natural gas revenues of $114.5 million as compared to oil and natural gas revenues of $70.2 million during the same period in 2013. This $44.3 million, or 63%, increase in revenues was primarily attributable to a 198% increase in net production to 2,431,955 BOE from 815,300 BOE, partially offset by a 45% decrease in realized BOE prices to $47.08 from $86.10 due to a shift in our production mix toward natural gas and NGLs for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013.

The following table summarizes our oil and natural gas production and related pricing for the three months ended June 30, 2014, as compared to such data for the three months ended June 30, 2013:

	Three months ended June 30,	
	2014	2013
Oil production volumes (MBbls)	709	535
Gas production volumes (MMcf)	8,972	1,415
Natural gas liquids production volumes (MGal)	9,539	1,861
Oil equivalents (MBOE)	2,432	815
Average oil price (per Bbl)	$95.95	$113.98
Average gas price (per Mcf)	$3.96	$4.80
Average natural gas liquids (per Gal)	$1.14	$1.29
Oil equivalents (per BOE)	$47.08	$86.10

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $12.7 million for the three months ended June 30, 2014 from $5.9 million for the three months ended June 30, 2013. This increase was mainly the result of an increase in expenses related to compressor repairs and maintenance, contract pumpers, contract labor and field supervision, environmental services, insurance, location repairs, rentals and salt water disposal.

Production Taxes. Production taxes increased slightly to $6.6 million for the three months ended June 30, 2014 from $6.4 million for the same period in 2013. This slight increase was primarily related to a 198% increase in production and changes in our product mix and production location.

Midstream Transportation, Processing and Marketing Expenses. Midstream transportation, processing and marketing expenses increased by $8.9 million to $10.8 million for the three months ended June 30, 2014 from $1.9 million for the same period in 2013. This increase was primarily attributable to midstream expenses related to our production volumes in the Utica Shale resulting from our 2013 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $56.0 million for the three months ended June 30, 2014, and consisted of $55.7 million in depletion of oil and natural gas properties and $0.3 million in depreciation of other property and equipment, as compared to total DD&A expense of $28.5 million for the three months ended June 30, 2013. This increase was due to an increase in our full cost pool as a result of our capital activities as well as an increase in our production, partially offset by an increase 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 $10.4 million for the three months ended June 30, 2014 from $4.9 million for the three months ended June 30, 2013. This $5.5 million increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in corporate fees, computer support, consulting fees and franchise taxes, partially offset by an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense remained relatively flat at $0.2 million for the three months ended June 30, 2014 and 2013.

Interest Expense. Interest expense decreased to $2.4 million for the three months ended June 30, 2014 from $3.3 million for the three months ended June 30, 2013 due primarily to an increase in the amount of interest capitalized in the three months ended June 30, 2014 as compared to June 30, 2013. We capitalized approximately $3.9 million and $2.9 million in interest expense to undeveloped oil and natural gas properties during the three months ended June 30, 2014 and June 30, 2013, respectively. This increase in capitalized interest in the 2014 period was the result of an increase in our undeveloped oil and natural gas properties. As of June 30, 2014, we had $40.0 million of total debt outstanding under our revolving credit facility and, as of June 30, 2013, we had no debt outstanding under our revolving credit facility. Total weighted debt outstanding under our facility was $14.5 million for the three months ended June 30, 2014. As of June 30, 2014, amounts borrowed under our revolving credit facility bore interest at the eurodollar rate of 1.66%.

Income Taxes. As of June 30, 2014, we had a net operating loss carry forward of approximately $4.2 million, in addition to numerous temporary differences, which gave rise to a net deferred tax liability. 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, 2014, a valuation allowance of $2.6 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized. We recognized an income tax expense of $31.5 million for the three months ended June 30, 2014.

Comparison of the Six Months Ended June 30, 2014 and 2013

We reported net income of $130.4 million for the six months ended June 30, 2014 as compared to $88.4 million for the six months ended June 30, 2013. This 48% increase in period-to-period net income was due primarily to $84.8 million of income recognized from our equity method investment in Blackhawk, $121.7 million of income recognized from our equity method investment in Diamondback and a 250% increase in net production to 4,869,806 BOE from 1,390,842 BOE, partially offset by a 47% decrease in realized BOE prices to $47.71 from $89.92, a $13.3 million increase in lease operating expenses, a $16.2 million increase in midstream transportation, processing and marketing expenses, a $10.6 million increase in general and administrative expenses, an expense of $24.0 million for litigation settlements and a $27.0 million increase in income tax expense for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013.

Oil and Gas Revenues. For the six months ended June 30, 2014, we reported oil and natural gas revenues of $232.4 million as compared to oil and natural gas revenues of $125.1 million during the same period in 2013. This $107.3 million, or 86%, increase in revenues was primarily attributable to a 250% increase in net production to 4,869,806 BOE from 1,390,842 BOE, partially offset by a 47% decrease in realized BOE prices to $47.71 from $89.92 due to a shift in our production mix toward natural gas and NGLs and a 32% decrease in average natural gas prices for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013.

The following table summarizes our oil and natural gas production and related pricing for the six months ended June 30, 2014, as compared to such data for the six months ended June 30, 2013:

Table of Contents

	Six months ended June 30,	
	2014	2013
Oil production volumes (MBbls)	1,436	1,052
Gas production volumes (MMcf)	16,634	1,734
Natural gas liquids production volumes (MGal)	27,774	2,084
Oil equivalents (MBOE)	4,870	1,391
Average oil price (per Bbl)	$98.49	$108.43
Average gas price (per Mcf)	$3.24	$4.76
Average natural gas liquids (per Gal)	$1.33	$1.31
Oil equivalents (per BOE)	$47.71	$89.92

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $24.3 million for the six months ended June 30, 2014 from $11.1 million for the six months ended June 30, 2013. This increase was mainly the result of an increase in expenses related to contract pumpers, contract labor and field supervision, insurance, environmental services, location repairs, rentals and salt water disposal.

Production Taxes. Production taxes increased slightly to $13.6 million for the six months ended June 30, 2014 from $13.3 million for the same period in 2013. This slight increase was primarily related to a 250% increase in production and changes in our product mix and production location.

Midstream Transportation, Processing and Marketing Expenses. Midstream transportation, processing and marketing expenses increased by $16.2 million to $18.5 million for the six months ended June 30, 2014 from $2.3 million for the same period in 2013. This increase was primarily attributable to midstream expenses related to our production volumes in the Utica Shale resulting from our 2013 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $112.9 million for the six months ended June 30, 2014, and consisted of $112.3 million in depletion of oil and natural gas properties and $0.6 million in depreciation of other property and equipment, as compared to total DD&A expense of $51.1 million for the six months ended June 30, 2013. This increase was due to an increase in our full cost pool as a result of our capital activities as well as an increase in our production, partially offset by an increase 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 $19.9 million for the six months ended June 30, 2014 from $9.3 million for the six months ended June 30, 2013. This $10.6 million increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in corporate fees, computer support, travel expense, consulting fees and franchise tax expense, partially offset by 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 $0.4 million for the six months ended June 30, 2014 from $0.3 million for the same period in 2013.

Interest Expense. Interest expense decreased to $6.3 million for the six months ended June 30, 2014 from $6.8 million for the six months ended June 30, 2013 due primarily to an increase in the amount of interest capitalized in the six months ended June 30, 2014 as compared to the same period in 2013. We capitalized approximately $6.2 million and $5.5 million in interest expense to undeveloped oil and natural gas properties during the six months ended June 30, 2014 and June 30, 2013, respectively. This increase in capitalized interest during the 2014 period was the result of an increase in our undeveloped oil and natural gas properties. As of June 30, 2014, we had $40.0 million of total debt outstanding under our revolving credit facility and, as of June 30, 2013, we had no debt outstanding under our revolving credit facility. Total weighted debt outstanding under our facility was $7.3 million for the six months ended June 30, 2014. As of June 30, 2014, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 1.66%.

Income Taxes. As of June 30, 2014, we had a net operating loss carry forward of approximately $4.2 million, in addition to numerous temporary differences, which gave rise to a net deferred tax liability. 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, 2014, a valuation allowance of $2.6 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized. We recognized an income tax expense of $80.7 million for the six months ended June 30, 2014.

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 credit facility and the issuances of equity and debt 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 2013, we received an aggregate of $733.8 million from the sale of shares of our common stock. In addition, we received an aggregate of $192.7 million in net proceeds from the sale of shares of our Diamondback common stock in 2013.

On June 24, 2014, we sold 1,000,000 shares of our Diamondback common stock in an underwritten public offering. The shares were sold to the public at $90.04 per share. We received an approximately $89.1 million in net proceeds from the sale of our shares of Diamondback common stock in this offering.

Net cash flow provided by operating activities was $201.5 million for the six months ended June 30, 2014 as compared to net cash flow provided by operating activities of $73.5 million for the same period in 2013. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 250% increase in our net BOE production and proceeds of $84.8 million from the sale of Blackhawk's equity interest in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC, partially offset by a 47% decrease in net realized BOE prices.

Net cash used in investing activities for the six months ended June 30, 2014 was $624.8 million as compared to $384.5 million for the same period in 2013. During the six months ended June 30, 2014, we spent $673.0 million in additions to oil and natural gas properties, of which $98.8 million was spent on our 2014 drilling and recompletion programs, $260.2 million was spent on expenses attributable to the wells drilled and recompleted during 2013, $3.2 million was spent on compressors and other facility enhancements, $4.2 million was spent on plugging costs, $101.1 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale and $176.2 million was spent on the acquisition of producing properties and non-producing leasehold interests in the Rhino acquisition, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $16.6 million was invested in Grizzly and $22.6 million was invested in our other equity investments during the six months ended June 30, 2014. We also received approximately $89.1 million from the sale of shares of our Diamondback common stock during the six months ended June 30, 2014. During the six months ended June 30, 2014, we used cash from operations and proceeds from our 2013 equity offerings for our investing activities.

Net cash provided by financing activities for the six months ended June 30, 2014 was $39.6 million as compared to net cash provided by financing activities of $358.3 million for the same period in 2013. The 2014 amount provided by financing activities is primarily attributable to borrowings under our revolving credit facility.

Credit Facility. On December 27, 2013, we entered into an Amended and Restated Credit Agreement with The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders, which we refer to as the amended and restated credit agreement. The amended and restated credit agreement provides for a maximum facility amount of $1.5 billion and matures on June 6, 2018.

On April 23, 2014, we entered into a first amendment to the amended and restated credit agreement. The first amendment increased the letter of credit sublimit from $20.0 million to $70.0 million and provided for an increase in the borrowing base availability from $150.0 million to $275.0 million. The first amendment also made certain changes to the lenders and their respective lending commitments thereunder. As of June 30, 2014, approximately $40.0 million of indebtedness was outstanding under our revolving credit facility.

As of June 30, 2014, total funds available under our amended and restated credit agreement, after giving effect to an aggregate of $36.7 million of letters of credit, was $198.3 million. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Table of Contents

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 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (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 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars. At June 30, 2014, amounts borrowed under the revolving credit facility bore interest at the eurodollar rate (1.66%).

Our amended and restated credit agreement contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries' ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in our revolving credit facility. Our revolving 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 offerings, 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 these financial covenants at June 30, 2014.

Senior Notes. On October 17, 2012, we issued $250.0 million in aggregate principal amount of our 7.75% Senior Notes due 2020, or the October Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee.

On December 21, 2012, we issued an additional $50.0 million in aggregate principal amount of our 7.75% Senior Notes due 2020, or the December Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. The December Notes were issued as additional securities under the existing senior note indenture. The December Notes and the October Notes are treated as a single class of debt securities under the senior note indenture and are referred to collectively herein as the "Notes". We used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under our revolving credit facility. We used the remaining net proceeds of the October Notes Offering and the net proceeds of the December Notes Offering for general corporate purposes, which includes funding a portion of our 2013 capital development plan. In October 2013, as required by the terms of the senior note indenture, we exchanged the October Notes and the December Notes for $300.0 million aggregate principal amount of 7.75% senior notes due 2020 having substantially identical terms except that the exchange notes were registered under the Securities Act of 1933, as amended. We did not receive any proceeds from the issuance of the exchange note.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.75% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The Notes are senior unsecured obligations and rank equally in the right of payment with all of our other senior indebtedness and senior in right of payment to any of our future subordinated indebtedness. All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the Notes, provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of our future unrestricted subsidiaries. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our amended and restated credit agreement) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the Notes.

We may redeem some or all of the Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, we may redeem the Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Notes initially issued remains outstanding immediately after such redemption.

If we experience a change of control (as defined in the senior note indenture), we will be required to make an offer to repurchase the Notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. If we sell certain assets and fail to use the proceeds in a manner specified in the senior note indenture, we will be required to use the remaining proceeds to make an offer to repurchase the Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

The senior note indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions (primarily in the Utica Shale), to fund Grizzly's delineation drilling program and initial preparation of the Algar Lake facility and for investments in entities that may provide services to facilitate the development of our acreage. 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, (2) pursue acquisition and disposition opportunities and (3) pursue business integration opportunities.

Of our net reserves at December 31, 2013, 35.2% 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.

From January 1, 2014 through August 1, 2014, we spud 47 gross (34 net) wells in the Utica Shale. We currently expect our 2014 capital expenditures to be \$634.0 million to \$676.0 million to drill 85 to 95 gross (68 to 76 net) wells on our Utica Shale acreage. In addition, we currently expect to spend \$375.0 million to \$425.0 million in 2014 to acquire additional acreage in the Utica Shale.

From January 1, 2014 through August 1, 2014, we recompleted 60 existing wells and spud 17 new wells at our WCBB field. We currently intend to drill 22 to 24 new wells during 2014 at our WCBB field for aggregate estimated drilling and recompletion expenditures during 2014 of \$42.0 million to \$45.0 million.

In our Hackberry fields, from January 1, 2014 through August 1, 2014, we recompleted 35 existing wells and spud nine new wells. We currently intend to drill ten to twelve wells in our Hackberry fields in 2014. Total capital expenditures for our Hackberry fields during 2014 are estimated to be approximately \$24.0 million to \$26.0 million.

From January 1, 2014 through August 1, 2014, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2014.

As of June 30, 2014, our net investment in Grizzly was approximately \$203.4 million. Our capital requirements in 2014 related to Grizzly's activities are currently estimated to be approximately \$15.0 million to \$20.0 million.

We had capital expenditures of $1.6 million during the six months ended June 30, 2014 related to our interests in Thailand. We do not currently anticipate any additional capital expenditures in Thailand in 2014.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the first quarter of 2013, we participated in the formation of

Stingray Energy with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure, Stingray Cementing and Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk and Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Midstream which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie, which is engaged in the processing and sale of hydraulic fracturing grade sand. See Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments. In the year ended December 31, 2013, we invested approximately $10.0 million in these entities. In the six months ended June 30, 2014, we invested approximately $21.0 million in these entities, and we expect to invest approximately $20.0 million to $23.0 million in these entities in 2014. We are currently evaluating the possibility of contributing our interests in Stingray Energy, Stingray Pressure Pumping, Stingray Cementing, Stingray Logistics, Bison and Muskie to a newly formed limited partnership. The holders of the other interests in these entities would also contribute their interests in these and other entities to the limited partnership which would undertake an initial public offering. A registration statement on Form S-1 has been submitted to the SEC on a confidential basis in connection with these entities, and we may choose to pursue an initial public offering of some or all of these entities later this year subject to market conditions. In January 2014, Blackhawk completed the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of $190.0 million, of which we received $84.8 million in net proceeds.

Our total capital expenditures for 2014 are currently estimated to be in the range of $715.0 million to $767.0 million. In addition, we currently expect to spend $375.0 million to $425.0 million in 2014 to acquire additional Utica Shale acreage, which includes the $184.0 million acquisition of approximately 8,000 net acres from Rhino in March 2014. Our total capital expenditures for the six months ended June 30, 2014 were approximately $230.4 million, excluding our Utica shale acreage acquisition. Approximately 88% of our 2014 estimated capital expenditures are currently expected to be spent in the Utica Shale. This range is up from the $513.5 million spent on 2013 activities, excluding Utica leasehold acquisitions, primarily due to the significant increase in our acreage position in the Utica Shale and our contemplated Utica development plans. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We believe that our cash on hand, cash flow from operations, sales of our Diamondback common stock, and borrowings under our amended and restated credit agreement 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 program or pursue additional acquisitions, or Grizzly's oil sands projects are accelerated, 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

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past six years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel 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 $13.31 per MMBtu in July 2008. On August 1, 2014, the West Texas Intermediate posted price for crude oil was $97.88 per barrel and the Henry Hub spot market price of natural gas was $3.80 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 on our oil and natural gas production, we had the following open fixed price swaps and swaptions at June 30, 2014:

Table of Contents

	Volume (barrels per day)	Weighted Average Price ($ per Bbl)
Fixed Price Swaps:		
July 2014 - December 2014	2,000	$101.50
	Volume (MMBtu per day)	Weighted Average Price ($ per MMBtu)
Fixed Price Swaps and Swaptions:		
July 2014 - December 2014	155,000	$4.07
January 2015 - December 2015	175,000	$4.08
January 2016 - March 2016	105,000	$4.04
April 2016	95,000	$4.04

Under the 2014 contracts, we have hedged approximately 59% to 67% of our expected 2014 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 fixed price swaps are recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Commitments

In connection with our 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 our abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we could access the trust for use in plugging and abandonment charges associated with the property, but have not yet done so. As of June 30, 2014, the plugging and abandonment trust totaled approximately $3.1 million. At June 30, 2014, we have plugged 378 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2013.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of June 30, 2014.

New Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. ASU 2014-08 changes the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. The ASU is effective for annual and interim periods beginning after December 15, 2014,

43

however, early adoption is permitted. We early adopted this ASU on a prospective basis beginning with the second quarter of 2014. The adoption did not have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. We are in the process of evaluating the impact on our consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE 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 six 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 Bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per MMBtu in September 2009 to a high of $13.31 per MMBtu in July 2008. On May 1, 2014, the West Texas Intermediate posted price for crude oil was $97.88 per barrel and the Henry Hub spot market price of natural gas was $3.80 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 on our oil and natural gas production, we had the following open fixed price swaps and swaptions at June 30, 2014:

	Volume (barrels per day)	Weighted Average Price ($ per Bbl)
Fixed Price Swaps:		
July 2014 - December 2014	2,000	$101.50

Table of Contents

	Volume (MMBtu per day)	Weighted Average Price ($ per MMBtu)
Fixed Price Swaps and Swaptions:		
July 2014 - December 2014	155,000	$4.07
January 2015 - December 2015	175,000	$4.08
January 2016 - March 2016	105,000	$4.04
April 2016	95,000	$4.04

Under our 2014 contracts, we have hedged approximately 59% to 67% of our estimated 2014 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 fixed price swaps are recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At June 30, 2014, we had a net liability derivative position of $29.2 million as compared to a net liability derivative position of $1.0 million as of June 30, 2013, 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 $43.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $43.8 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 amended and restated credit agreement 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, 2014, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 1.66%. A 1% increase in interest rates would increase interest expense by approximately $0.4 million per year, based on $40.0 million outstanding under our revolving credit facility as of June 30, 2014. As of June 30, 2014, 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, President and Interim 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 Exchange Act 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, President and Interim Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of June 30, 2014, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer, President and Interim 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 Exchange Act. Based upon our evaluation, our Chief Executive Officer, President and Interim Chief Financial Officer has concluded that, as of June 30, 2014, 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.

Table of Contents

PART II

ITEM 1. LEGAL PROCEEDINGS

We have previously provided disclosure regarding three separate lawsuits filed by the Louisiana Department of Revenue (“LDR”) disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2010. In June 2014, we entered into a settlement agreement with LDR under which we paid $6.0 million, which is included in litigation settlement in the accompanying consolidated statements of operations, and LDR released all claims for severance taxes for tax years 2005 to 2010 and dismissed all three lawsuits with prejudice.

We have previously provided disclosure regarding a lawsuit filed entitled Reeds et al. v. BP American Production Company et al., in the 38th Judicial District Court of Louisiana, Case No. 10-18714, filed against 15 oil and gas defendants on July 30, 2010 by six individuals and one limited liability company in Cameron Parish Louisiana for surface contamination in areas where we and other defendants operated. In 2014, we have had settlement discussions with the plaintiffs focused on our payment of approximately $18.0 million plus the cost of a plan of remediation to be approved by the Court and the Louisiana Department of Natural Resources. The settlement has not yet been finalized and there can be no assurance that a settlement will be reached on these or any other terms. We have accrued the $18.0 million proposed settlement as of June 30, 2014, which is included in litigation settlement in the accompanying consolidated statements of operations. The case was set for trial in July 2014, but plaintiffs’ counsel filed a motion to continue the trial, which was granted, so the parties could work on settlement of the matter. There is no new trial date set at this time, and the lawsuit is not being actively litigated.

Due to the current stage of the Reeds lawsuit and settlement discussions, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. An adverse decision in the matter could have a material adverse effect on our financial condition or results of operations.

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

ITEM 1A. RISK FACTORS

See risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2013.

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, 2014, 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.

Table of Contents

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Contribution Agreement, dated May 7, 2012, by and between the Company and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 8, 2012).
2.2	Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 18, 2012).
2.3	Amendment, dated December 19, 2012, to the Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 20, 2012).
2.4	Purchase and Sale Agreement, dated February 11, 2013, by and between Windsor Ohio, LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 15, 2013).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
3.5	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company on May 2, 2014).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).

4.2	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.3	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.4	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).

Table of Contents

4.5	Indenture, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Gulfport Energy Corporation's 7.750% Senior Note Due November 1, 2020) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.6	Registration Rights Agreement, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.7	First Supplemental Indenture, dated December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
4.8	Registration Rights Agreement, dated as of December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
4.9	Investor Rights Agreement, dated as of October 11, 2012, between Gulfport Energy Corporation and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 17, 2012).
10.1+	2014 Executive annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 7, 2014).
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2014, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 28, 2014).
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.

101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

\+ Management contract, compensatory plan or arrangement.

Table of Contents

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: August 7, 2014

GULFPORT ENERGY CORPORATION

By:	/s/ MICHAEL G. MOORE
	Michael G. Moore
	Chief Executive Officer, President and Interim Chief Financial Officer