Sanchez Production Partners LP
Form 10-Q
November 13, 2015
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2015

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to .

Commission File Number 001-33147

Sanchez Production Partners LP

(Exact Name of Registrant as Specified in Its Charter)

Delaware	11-3742489
(State of organization)	(I.R.S. Employer Identification No.)

1000 Main Street, Suite 3000	
Houston, Texas	77002
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: (713) 783-8000

none

(Former name, former address and former fiscal year, if changed since last report)

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 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 pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

Large accelerated filer		Accelerated filer
Non-accelerated filer	(Do not check if a smaller reporting company)	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

Common units outstanding as of November 13, 2015: Approximately 3,048,283 units.

Table of Contents

TABLE OF CONTENTS

		Page
PART I—Financial Information		3
Item 1.	Financial Statements	3
	Condensed Consolidated Statements of Operations	3
	Condensed Consolidated Balance Sheets	4
	Condensed Consolidated Statements of Cash Flows	5
	Condensed Consolidated Statements of Changes in Members' Equity/Partners' Capital	6
	Notes to Condensed Consolidated Financial Statements	7
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	24
	Results of Operations	27
	Liquidity and Capital Resources	34
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	37
Item 4.	Controls and Procedures	37
PART II—Other Information		38
Item 1.	Legal Proceedings	38
Item1A.	Risk Factors	38
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	40
Item 3.	Defaults Upon Senior Securities	41
Item 4.	Mine Safety Disclosures	41
Item 5.	Other Information	41
Item 6.	Exhibits	41
Signatures		43

Table of Contents

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Operations

(In thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Revenues				
Natural gas sales	$ 5,730	$ 9,153	$ 15,946	$ 21,752
Oil sales	19,501	11,402	25,104	21,784
Natural gas liquids sales	394	841	1,280	1,690
Total revenues	25,625	21,396	42,330	45,226
Expenses:				
Operating expenses:				
Lease operating expenses	5,194	5,296	15,452	15,598
Cost of sales	139	404	469	1,198
Production taxes	443	796	1,396	2,563
General and administrative	7,376	3,780	20,669	12,942
(Gain) loss on sale of assets	2	—	(111)	(23)
Depreciation, depletion and amortization	2,851	4,836	9,050	13,206
Asset impairments	937	43	84,664	237
Accretion expense	265	151	782	451
Total operating expenses	17,207	15,306	132,371	46,172
Other expense (income)				
Interest expense	672	511	2,440	1,569
Other expense (income)	(52)	(76)	48	(220)
Total other expenses	620	435	2,488	1,349
Total expenses	17,827	15,741	134,859	47,521
Income (loss) before income taxes	7,798	5,655	(92,529)	(2,295)
Income tax expense	3	—	3	—
Net income (loss)	7,795	5,655	(92,532)	(2,295)
Less:				
Preferred unit paid-in-kind distributions	(445)	—	(969)	—
Net income (loss) attributable to common unitholders	$ 7,350	$ 5,655	$ (93,501)	$ (2,295)
Income (loss) per unit				
Net income (loss) per unit prior to conversion (1)				
Class A units - Basic	$ —	$ 2.33	$ (0.38)	$ (0.54)
Class B units - Basic	$ —	$ 1.94	$ (0.31)	$ (0.79)
Class A units - Diluted	$ —	$ 2.33	$ (0.38)	$ (0.54)
Class B units - Diluted	$ —	$ 1.93	$ (0.31)	$ (0.79)

Weighted Average Units Outstanding prior to conversion (1)				
Class A units - Basic	—	48,451	48,451	85,720
Class B units - Basic	—	2,855,257	2,879,163	2,835,859
Class A units - Diluted	—	48,451	48,451	85,720
Class B units - Diluted	—	2,866,088	2,879,163	2,835,859
Net income (loss) per unit after conversion (1)				
Common units - Basic	$ 2.33	$ —	$ (29.83)	$ —
Common units - Diluted	$ 0.55	$ —	$ (29.83)	$ —
Weighted Average Units Outstanding after conversion (1)				
Common units - Basic	3,124,004	—	3,103,608	—
Common units - Diluted	14,074,856	—	3,103,608	—

(1) Amounts adjusted for 1-for-10 reverse split completed August 3, 2015. See Note 13.

See accompanying notes to condensed consolidated financial statements.

Table of Contents

SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except per unit data)

ASSETS	September 30, 2015 (unaudited)	December 31, 2014
Current assets		
Cash and cash equivalents	$ 8,963	$ 4,238
Restricted cash	600	1,748
Accounts receivable	3,103	3,901
Accounts receivable - related entities	681	959
Prepaid expenses	1,108	1,783
Fair value of derivative instruments	17,784	14,671
Total current assets	32,239	27,300
Oil and natural gas properties and related equipment (successful efforts method)		
Oil and natural gas properties, equipment and facilities	732,766	651,493
Material and supplies	1,056	1,056
Less accumulated depreciation, depletion, amortization, accretion and impairments	(610,279)	(517,239)
Oil and natural gas properties and equipment, net	123,543	135,310
Other assets		
Debt issuance costs	1,571	689
Fair value of derivative instruments	10,124	8,158
Other non-current assets	2,302	1,790
Total assets	$ 169,779	$ 173,247
LIABILITIES AND MEMBERS' EQUITY/PARTNERS' CAPITAL		
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 9,663	$ 5,759
Royalties payable	680	1,134
Total current liabilities	10,343	6,893
Other liabilities		
Asset retirement obligation	18,593	17,031
Long-term debt	106,000	42,500
Total other liabilities	124,593	59,531
Total liabilities	134,936	66,424
Commitments and contingencies (See Note 9)		
Members' equity / Partners' capital		
Class A units, Zero and 48,451(1) units issued and outstanding as of September 30, 2015 and December 31, 2014, respectively	—	1,930
	—	104,893

Class B units, Zero and 2,879,258(1) units issued and outstanding as of September 30, 2015 and December 31, 2014, respectively				
Class A preferred units, 11,130,855 and zero units issued and outstanding as of September 30, 2015 and December 31, 2014, respectively		15,826		—
Common units, 3,149,693(1) and zero units issued and outstanding as of September 30, 2015 and December 31, 2014, respectively		19,017		—
Total members' equity/partners' capital		34,843		106,823
Total liabilities and members' equity/partners' capital	$	169,779	$	173,247

(1) Amounts adjusted for 1-for-10 reverse split completed August 3, 2015. See Note 13.

See accompanying notes to condensed consolidated financial statements.

Table of Contents

SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(Unaudited)

	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities:		
Net loss	$ (92,532)	$ (2,295)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation, depletion and amortization	9,050	13,206
Asset impairments	84,664	237
Amortization of debt issuance costs	413	199
Accretion expense	782	451
Equity earnings in affiliate	(2)	(147)
Gain from disposition of property and equipment	(111)	(23)
Bad debt expense	122	80
Total mark-to-market gains (losses) on commodity derivative contracts	(16,256)	1,134
Cash mark-to-market settlements on commodity derivative contracts	13,441	4,184
Unit-based compensation programs	2,463	1,216
Changes in Operating Assets and Liabilities:		
(Increase) decrease in accounts receivable	1,820	(408)
Decrease in accounts receivable - related entities	278	49
Decrease in prepaid expenses	675	869
(Increase) decrease in other assets	(867)	3
Increase (decrease) in accounts payable/accrued liabilities	5,195	(4,603)
Decrease in royalties payable	(454)	(70)
Decrease in other liabilities	—	(1,398)
Net cash provided by operating activities	8,681	12,684
Cash flows from investing activities:		
Cash paid for acquisitions	(81,378)	(1,351)
Development of oil and natural gas properties	(1,313)	(5,025)
Proceeds from sale of assets	470	58
Distributions from equity affiliate	60	180
Net cash used in investing activities	(82,161)	(6,138)
Cash flows from financing activities:		
Proceeds from issuance of preferred units	17,375	—
Payments for offering costs	(810)	—
Proceeds from issuance of debt	106,000	5,750
Repayment of debt	(42,500)	(4,500)

Issuance of common units	52	—
Repurchase of Class A, Class C and Class D interests	—	(2,468)
Units tendered by employees for tax withholdings	(618)	(415)
Debt issuance costs	(1,294)	(136)
Net cash provided by (used in) financing activities	78,205	(1,769)
Net increase in cash and cash equivalents	4,725	4,777
Cash and cash equivalents, beginning of period	4,238	4,894
Cash and cash equivalents, end of period	$ 8,963	$ 9,671
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ (149)	$ (219)
Acquisition of oil and natural gas properties in exchange for common units	2,000	—
Cash paid during the period for interest	(1,973)	(1,379)

See accompanying notes to condensed consolidated financial statements.

5

Table of Contents

SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Members’ Equity/Partners’ Capital

(In thousands, except unit data)

(Unaudited)

	Class A Units		Class B Units		Class A Preferred Units		Common Units		Total
	Units(1)	Amount	Units(1)	Amount	Units	Amount	Units(1)	Amount	Equity/Cap
Members' Equity, December 31, 2014	48,451	$ 1,930	2,879,258	$ 104,893	—	$ —	—	$ —	$ 106,823
Units tendered by employees for tax withholding	—	—	(1,557)	(21)	—	—	—	—	(21)
Net loss (January 1st - March 5th)	—	(18)	—	(905)	—	—	—	—	(923)
Members' Equity, March 5, 2015	48,451	1,912	2,877,701	103,967	—	—	—	—	105,879
Class A Units converted to common units upon limited partnership conversion	(48,451)	(1,912)	—	—	—	—	58,729	1,912	—
Class B Units converted to common units upon limited partnership conversion	—	—	(2,877,701)	(103,967)	—	—	2,877,701	103,967	—
Units tendered by employees for tax withholding	—	—	—	—	—	—	(32,269)	(597)	(597)
	—	—	—	—	—	—	137,257	2,463	2,463

Unit-based compensation programs									
Private placement of Class A Preferred Units, net of offering costs of $810	—	—	—	—	10,859,375	16,550	—	—	16,550
Beneficial conversion feature of Class A preferred units	—	—	—	—	—	(1,693)	—	1,693	—
Common units issued for acquisition of properties	—	—	—	—	—	—	105,263	2,000	2,000
Issuance of common units	—	—	—	—	—	—	3,012	157	157
Preferred unit paid-in-kind distributions	—	—	—	—	271,480	969	—	(969)	—
Net loss (March 6th - September 30th)	—	—	—	—	—	—	—	(91,609)	(91,609)
Partners' Capital, September 30, 2015	—	$ —	—	$ —	11,130,855	$ 15,826	3,149,693	$ 19,017	$ 34,843

(1) Amounts adjusted for 1-for-10 reverse split completed August 3, 2015. See Note 13.

See accompanying notes to condensed consolidated financial statements.

Table of Contents

SANCHEZ PRODUCTION PARTNERS LP AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Sanchez Production Partners LP, a Delaware limited partnership ("SPP", "we", "us", "our" or the "Partnership"), is a publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy production assets. SPP completed its initial public offering on November 20, 2006, as Constellation Energy Partners LLC ("CEP" or the "Company"). We have entered into a shared services agreement (the "Services Agreement") with SP Holdings, LLC (the "Manager"), the sole member of our general partner, pursuant to which the Manager provides services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance and acquisition, disposition and financing services. On March 6, 2015, the Company's unitholders approved the conversion of Sanchez Production Partners LLC to a Delaware limited partnership and the name was changed to Sanchez Production Partners LP. The Manager owns the general partner of SPP and all of SPP's incentive distribution rights. Our common units are currently listed on the NYSE MKT under the symbol "SPP."

Historically, our operations have consisted of the exploration and production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale from Sanchez Energy Corporation ("SN") and entered into a 15-year gathering and processing agreement with SN. We have also commenced a process to sell our oil and gas properties in the Mid-Continent region.

As a result of the acquisition of midstream assets from SN and the proposed disposition of our oil and gas properties located in the Mid-Continent region, our historical financial statements (including those in this Form 10-Q) will differ substantially from our future financial statements beginning with the quarter ending December 31, 2015 principally because a significant portion of our revenues will come from the long-term, fee-based gathering and processing agreement with SN rather than from oil and natural gas production.

Basis of Presentation

These unaudited condensed consolidated financial statements include the accounts of SPP and our wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation. We operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. Our management evaluates performance based on one business segment as there are not different economic environments within the operation of our oil and natural gas properties.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules of the Securities and Exchange Commission ("SEC"). Certain information and footnote disclosures, normally included in annual financial statements prepared in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"), have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information presented not misleading. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, necessary to fairly state the financial position, results of operations and cash flows with respect to the interim condensed consolidated financial statements have been included. The results of operations for the interim periods are not necessarily indicative of the results for the entire year.

These unaudited condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto of the Company and our subsidiaries included in our Annual Report on Form 10-K for the year ended December 31, 2014, which was filed with the SEC on March 5, 2015.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and accompanying footnotes. These estimates and

Table of Contents

the underlying assumptions affect the amounts of assets and liabilities reported, disclosures about contingent assets and liabilities and reported amounts of revenues and expenses. The estimates that are particularly significant to our financial statements include estimates of our reserves of oil, natural gas and natural gas liquids (“NGLs”); future cash flows from oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; certain revenues and operating expenses; fair values of commodity derivatives and fair values of assets and liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management’s best estimates and judgment. Management evaluates its estimates and assumptions on an on-going basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from the estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Reclassifications

Certain reclassifications have been made to the prior period to conform to the current period presentation. These reclassifications had no effect on total unitholders’ equity, net income or net cash provided by or used in operating, investing or financing activities and an immaterial effect on total assets and total liabilities.

Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (“FASB”), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not effective, will not have a material impact on our condensed consolidated financial statements upon adoption.

In April 2015, FASB issued Accounting Standards Update (“ASU”) No. 2015-03, “Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs.” This guidance is intended to more closely align the presentation of debt issuance costs under U.S. GAAP with the presentation requirements under International Financial Reporting Standards. Under this new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as a separate asset as previously presented. This guidance is effective for fiscal years and interim periods beginning after December 15, 2015. The guidance is to be applied retrospectively to each prior period presented. Early adoption is permitted. The effects of this accounting standard on our financial position, results of operations and cash flows are not expected to be material.

In February 2015, the FASB issued an ASU No. 2015-02, “Consolidation (Topic 810): Amendments to the Consolidation Analysis” to improve consolidation guidance for certain types of legal entities. The guidance modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (“VIEs”) or voting interest entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for certain money market funds. These provisions are effective for annual reporting periods beginning after December 15, 2015, and interim periods within those annual periods, with early adoption permitted. These provisions may also be adopted using either a full retrospective or a modified retrospective approach. We are currently assessing the impact that adopting this new accounting guidance will have on our consolidated financial statements and footnote disclosures, but we do not expect the impact to be material.

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is not permitted. The guidance may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

Table of Contents

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Partnership's financial position, results of operations and cash flows.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2014.

Cash

All highly liquid investments with original maturities of three months or less are considered cash. Checks-in-transit are included in our consolidated balance sheets as accounts payable or as a reduction of cash, depending on the type of bank account the checks were drawn on. There were no checks-in-transit reported in accounts payable at September 30, 2015 and December 31, 2014.

Restricted Cash

Restricted cash, as of September 30, 2015 and December 31, 2014, of $0.6 million and $1.7 million, respectively, was being held in escrow. The balance as of September 30, 2015 is related to a vendor dispute, and will remain in the escrow account until the dispute has been resolved.

Accounts Receivable, Net

Our accounts receivable are primarily from purchasers of oil and natural gas and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserves until substantially all collection efforts have been exhausted. At September 30, 2015 and December 31, 2014, we had an allowance for doubtful accounts receivable of $0.4 million and $0.2 million, respectively.

3. ACQUISITIONS AND DIVESTITURES

Eagle Ford Acquisition

On March 31, 2015, we completed an acquisition of wellbore interests in certain producing oil and natural gas properties in Gonzales County, Texas (the "Eagle Ford properties," and such acquisition, the "Eagle Ford acquisition") located in the Eagle Ford Shale in Gonzales County, Texas from SN for a purchase price of $85 million, subject to normal and customary closing adjustments. The effective date of the transaction was January 1, 2015. The acquisition included initial conveyed working interests and net revenue interests for each property which escalate on January 1 for each year from 2016 through 2019, at which point, SPP's interests in the Eagle Ford properties will stay constant for the remainder of the respective lives of the assets.

The adjusted purchase price of $83.4 million was funded at closing with net proceeds from the private placement of 10,625,000 newly created Class A Preferred Units which were issued for a cash purchase price of $1.60 per unit, resulting in gross proceeds to SPP of $17.0 million, the issuance of 1,052,632 common units (approximately 105,263 common units after adjusting for reverse unit split) to SN, borrowings under the Partnership's Credit Agreement (as defined in Note 7, "Long-Term Debt"), and available cash. The total

9

Table of Contents

purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved developed reserves	$ 72,889
Facilities	8,002
Fair value of hedges assumed	3,408
Fair value of assets acquired	84,299
Asset retirement obligations	(877)
Ad valorem tax liability	(44)
Fair value of net assets acquired	$ 83,378

Western Catarina Midstream Acquisition

On October 14, 2015, we completed an acquisition of midstream assets located in Western Catarina, in the Eagle Ford Shale in South Texas from SN for a purchase price of $345.8 million, subject to normal and customary closing adjustments (the "Western Catarina Midstream acquisition"). The purchase price was funded at closing with net proceeds from the sale of Class B Preferred Units to Stonepeak Catarina Holdings LLC, an affiliate of Stonepeak Infrastructure Partners ("Stonepeak") and available cash. Additionally, as a result of the Western Catarina Midstream acquisition, we repurchased 105,263 common units previously held by a subsidiary of SN.

Pro Forma Operating Results

The following unaudited pro forma combined financial information for the three and nine months ended September 30, 2015 and 2014 reflect the consolidated results of operations of the Partnership as if the Western Catarina Midstream and Eagle Ford acquisitions and related financings had occurred on January 1, 2014. The pro forma information includes adjustments primarily for revenues and expenses from the acquired properties, depreciation, depletion, amortization and accretion, interest expense and debt issuance cost amortization for acquisition debt, amortization of customer contract intangible assets acquired and paid-in-kind units issued in connection with the Class A Preferred Units.

The unaudited pro forma combined financial statements give effect to the events set forth below:

- The Western Catarina Midstream acquisition completed on October 14, 2015.
- Issuance of Class B Preferred Units to finance the Western Catarina Midstream acquisition.
- Repurchase of common units issued to finance a portion of the Eagle Ford acquisition as a part of the Western Catarina Midstream acquisition, and the related effect on net income (loss) per common unit.
- The Eagle Ford acquisition completed on March 31, 2015.
- The increase in borrowings under the Credit Agreement to finance a portion of the Eagle Ford acquisition, and the related adjustments to interest expense.
- Issuance of Class A Preferred Units to finance a portion of the Eagle Ford acquisition, and the related adjustments to preferred paid-in-kind distributions.

Table of Contents

· Issuance of common units to finance a portion of the Eagle Ford acquisition and the related effect on net income (loss) per common unit (in thousands, except per unit amounts).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues	$ 36,219	$ 43,534	$ 77,341	$ 115,449
Net income (loss) attributable to common unitholders	$ 1,109	$ 5,522	$ (112,483)	$ 633
Net income (loss) per unit prior to conversion				
Class A units - Basic and diluted(1)	$ —	$ 6.40	$ (23.83)	$ 7.13
Class B units - Basic(1)	$ —	$ 5.43	$ (18.95)	$ 10.56
Class B units - Diluted(1)	$ —	$ 0.80	$ (18.95)	$ 1.88
Net income (loss) per unit after conversion				
Common units - Basic(1)	$ 3.38	$ —	$ (8.74)	$ —
Common units - Diluted(1)	$ 0.60	$ —	$ (8.74)	$ —

(1) Amounts adjusted for 1-for-10 reverse split completed August 3, 2015. See Note 13.

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Partnership would have reported had the Western Catarina Midstream and Eagle Ford acquisitions and related financings been completed as of the date set forth in this unaudited pro forma combined financial information and should not be taken as indicative of the Partnership's future combined results of operations. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

Post-Acquisition Operating Results

The amounts of revenue and excess of revenues over direct operating expenses included in the Partnership's condensed consolidated statements of operations for the three and nine months ended September 30, 2015, for the Eagle Ford acquisition are shown in the table that follows. Direct operating expenses include lease operating expenses and production and ad valorem taxes (in thousands):

	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
Revenues	$ 2,390	$ 5,718
Excess of revenues over direct operating expenses	$ 1,439	$ 3,742

4. FAIR VALUE MEASUREMENTS

Measurements of fair value of derivative instruments are classified according to the fair value hierarchy, which prioritizes the inputs to the valuation techniques used to measure fair value. Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that can be valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Table of Contents

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). The valuation models used to value derivatives associated with the Partnership's oil and natural gas production are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although third party quotes are utilized to assess the reasonableness of the prices and valuation techniques, there is not sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2015 (in thousands):

	Fair Value Measurements at September 30, 2015				
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at September 30, 2015
Derivative assets	$ —	$ 27,908	$ —	$ —	$ 27,908
Total net assets	$ —	$ 27,908	$ —	$ —	$ 27,908

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 (in thousands):

	Fair Value Measurements at December 31, 2014				
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2014
Derivative assets	$ —	$ 22,919	$ —	$ (90)	$ 22,829
Derivative liabilities	—	(90)	—	90	—
Total net assets	$ —	$ 22,829	$ —	$ —	$ 22,829

As of September 30, 2015 and December 31, 2014, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value on a Non-Recurring Basis

The Partnership follows the provisions of Accounting Standards Codification ("ASC") Topic 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change. Our purchase price allocation for the Eagle Ford acquisition is presented in Note 3, ''Acquisitions and Divestitures." A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 8, ''Asset Retirement Obligations.''

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Table of Contents

Credit Agreement – We believe that the carrying value of long-term debt for our Credit Agreement approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms. The debt is classified as a Level 2 input in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. Our Credit Agreement is discussed further in Note 7, "Long-Term Debt."

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We did not have any interest rate derivatives as of September 30, 2015. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value.

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These transactions are normally price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, Derivatives and Hedging, all derivative instruments are recorded on the condensed consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have not elected to designate any of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included in natural gas sales and oil and liquids sales in the condensed consolidated statements of operations.

As of September 30, 2015, we had the following derivative contracts in place for the periods indicated, all of which are accounted for as mark-to-market activities:

Fixed Price Basis Swaps–West Texas Intermediate (WTI)

	For the Quarter Ended (in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2015							109,582	$ 75.64	109,582	$ 75.64
2016	121,005	$ 73.53	113,226	$ 73.77	106,483	$ 73.95	100,525	$ 74.10	441,239	$ 73.82
2017	57,953	$ 64.80	54,554	$ 64.80	51,570	$ 64.80	48,926	$ 64.80	213,003	$ 64.80
2018	56,798	$ 65.40	54,197	$ 65.40	51,851	$ 65.40	49,709	$ 65.40	212,555	$ 65.40

2019	52,760	$ 65.65	50,784	$ 65.65	48,960	$ 65.65	47,264	$ 65.65	199,768	$ 65.65
									1,176,147	

13

Table of Contents

Fixed Price Swaps—NYMEX (Henry Hub)

	For the Quarter Ended (in MMBtu)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2015							1,118,334	$ 4.17	1,118,334	$ 4.17
2016	1,098,689	$ 4.13	1,048,146	$ 4.14	998,394	$ 4.14	963,327	$ 4.14	4,108,556	$ 4.14
2017	80,563	$ 3.52	75,829	$ 3.52	71,672	$ 3.52	67,984	$ 3.52	296,048	$ 3.52
2018	79,042	$ 3.58	75,404	$ 3.58	72,115	$ 3.58	69,122	$ 3.58	295,683	$ 3.58
2019	73,432	$ 3.62	70,648	$ 3.62	68,088	$ 3.62	65,720	$ 3.62	277,888	$ 3.62
									6,096,509	

The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the nine months ended September 30, 2015 and the year ended December 31, 2014 (in thousands):

	September 30, 2015	December 31, 2014
Beginning fair value of commodity derivatives	$ 22,829	$ 10,601
Net gains on crude oil derivatives	15,321	13,983
Net gains on natural gas derivatives	4,343	5,871
Net settlements on derivative contracts:		
Crude oil	(9,532)	69
Natural gas	(5,053)	(7,695)
Ending fair value of commodity derivatives	$ 27,908	$ 22,829

The effect of derivative instruments on our condensed consolidated statements of operations was as follows (in thousands):

		Amount of Gain/(Loss) in Income			
	Location of Gain/(Loss)	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Derivative Type	in Income	2015	2014	2015	2014
Commodity – Mark-to-Market	Oil sales	$ 14,970	$ 4,904	$ 12,058	$ (98)
Commodity – Mark-to-Market	Natural gas sales	2,352	2,767	4,200	(1,036)
		$ 17,322	$ 7,671	$ 16,258	$ (1,134)

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with four counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. We include a measure of counterparty credit risk in our estimates of the fair values of derivative instruments. As of September 30, 2015 and December 31, 2014, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

Table of Contents

Hedges Novated in the Eagle Ford Acquisition

As a part of the Eagle Ford acquisition, we received by novation from the seller certain hedges covering approximately 95%, 90%, 85%, 85% and 80% of estimated 2015, 2016, 2017, 2018 and 2019 oil and natural gas production from the acquired assets, respectively. The counterparty for the hedges is a lender in the Partnership's Credit Agreement. The Partnership is responsible for all future periodic settlements of these transactions. As of September 30, 2015, the fair value of the hedges assumed resulted in a $10.4 million asset in our condensed consolidated balance sheet.

6. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consisted of the following (in thousands):

	September 30, 2015	December 31, 2014
Oil and natural gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 730,678	$ 649,432
Unproved property	1,587	1,560
Land	501	501
Total property costs	732,766	651,493
Materials and supplies	1,056	1,056
Total	733,822	652,549
Less: Accumulated depreciation, depletion, amortization and impairments	(610,279)	(517,239)
Oil and natural gas properties and equipment, net	$ 123,543	$ 135,310

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets

The Partnership evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows of proved and risk-adjusted probable and possible reserves are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change.

For the three and nine months ended September 30, 2015, we recorded non-cash charges of $0.9 million and $84.7 million, respectively, to impair the value of our Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties acquired prior to the Eagle Ford acquisition. For the nine months ended September 30, 2014, we recorded non-cash impairment charges of $0.2 million to impair the value of our oil and natural gas fields in Texas and Louisiana, with an immaterial amount being recorded during the three months ended September 30, 2014. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement.

Exploration and Dry Hole Costs

Exploration and dry hole costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs and the impairment, amortization and abandonment associated with leases on our unproved properties. We recorded no exploration and dry hole costs for the nine months ended September 30, 2015 and 2014.

7. LONG-TERM DEBT

Credit Agreement

On March 31, 2015, the Partnership, as borrower, entered into a Third Amended and Restated Credit Agreement with Royal Bank of Canada, as administrative agent and collateral agent and the lenders party thereto, providing for a reserve-based credit facility with a

Table of Contents

borrowing base of $110 million, a maximum commitment of $500 million and a maturity date of March 31, 2020 (the "Credit Agreement"). The Partnership used $106.0 million in borrowings under the Credit Agreement on March 31, 2015 to finance the Eagle Ford acquisition, in part, and to repay $42.5 million due under the Second Amended and Restated Credit Agreement, with Societe Generale as administrative and collateral agent and a syndicate of five lenders, which had a maximum commitment of $350 million and a borrowing base of $70.0 million immediately prior to its retirement.

Borrowings under the Credit Agreement are secured by various mortgages of oil and natural gas properties that the Partnership and certain of its subsidiaries own as well as various security and pledge agreements among the Partnership and certain of its subsidiaries and the administrative agent.

The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for the Partnership's oil and natural gas properties. Borrowings under the Credit Agreement are available for acquisition, exploration, operation, maintenance and development of oil and natural gas properties, payment of expenses incurred in connection with the Credit Agreement, working capital and general business purposes. The Credit Agreement has a sub-limit of $15 million which may be used for the issuance of letters of credit. The borrowing base as of September 30, 2015 was $110 million, of which we had $106 million outstanding. The borrowing base is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

At the Partnership's election, interest for borrowings under the Credit Agreement are determined by reference to (i) the London interbank rate, or LIBOR, plus an applicable margin between 1.75% and 2.75% per annum based on utilization or (ii) a domestic bank rate ("ABR") plus an applicable margin between 0.75% and 1.75% per annum based on utilization plus (iii) a commitment fee between 0.375% and 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, the Partnership's ability and certain of its subsidiaries' ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of the Partnership's assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions. Furthermore, the Credit Agreement contains financial covenants that require the Partnership to satisfy certain specified financial ratios, including (i) current assets to current liabilities of at least 1.0 to 1.0 at all times and (ii) total net debt to consolidated Adjusted EBITDA for the last twelve months of not greater than 4.5 to 1.0 as of the last day of any fiscal quarter.

The Credit Agreement also includes customary events of default, including events of default related to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) the Partnership's existing general partner (the "General Partner") ceases to be the sole general partner of the Partnership or (ii) certain specified persons shall cease to own more than 50% of the equity interests of the General Partner or shall cease to control, directly or indirectly, such General Partner. If an event of default occurs, the lenders may accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

The Credit Agreement limits the Partnership's ability to pay distributions to unitholders. The Partnership has the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Credit Agreement, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Credit Agreement exceed 90% of the borrowing base determined with respect to the Partnership's oil and natural gas properties, after giving effect to the proposed distribution. The Partnership's available cash is reduced by any cash reserves established by the board of directors of the General Partner for the proper conduct of the Partnership's business and the payment of fees and expenses.

The Credit Agreement permits us to hedge our projected monthly production from oil and natural gas properties, provided that (a) for the immediately ensuing twenty four-month period, the volumes of production hedged in any month may not exceed our projected monthly production from proved developed and producing reserves (or 90% of our projected monthly production from proved reserves, if greater); (b) for the immediately following twenty-four month period, volumes of production hedged in any month may not exceed

Table of Contents

90% of our projected monthly production from proved developed and producing reserves (or 85% of our projected monthly production from proved reserves, if greater); (c) for the immediately following twelve month period, volumes of production hedged in any month may not exceed 85% our projected monthly production from proved developed and producing reserves (or 80% of our projected monthly production from proved reserves, if greater); and (d) no hedges may have a tenor beyond five years. The Credit Agreement also permits us to hedge the interest rate on up to 75% of the then-outstanding principal amounts of our indebtedness for borrowed money.

On October 14, 2015, in conjunction with the closing of the Western Catarina Midstream acquisition, the Partnership entered into the Joinder, Assignment and Second Amendment to the Credit Agreement with a syndicate of nine lenders (the "Amended Credit Agreement"). Pursuant to the amendment, the borrowing base under the Credit Facility increased from $110 million to $200 million, excluding the value of the Partnership's Oklahoma and Kansas assets. Debt outstanding as of the date of the amendments was unchanged at $106 million. As a result of the amendment, which resulted in lower utilization of the borrowing base, the interest rate paid by the Partnership on the debt outstanding decreased by 0.50%.

The borrowing base under the Amended Credit Agreement is re-determined semi-annually in the second and fourth quarters of the year with respect to our oil and gas properties and quarterly with respect to our midstream properties based on, among other things, reserve reports as prepared by petroleum engineers, prevailing oil and natural gas prices, and our operating results. The borrowing base may be re-determined at our request more frequently and by the lenders, at any time, in their sole discretion. The next regularly scheduled borrowing base redetermination is expected to occur in the second quarter 2016.

The Amended Credit Agreement contains various covenants that limit, among other things, the Partnership's ability and certain of its subsidiaries' ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of the Partnership's assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions. In addition, the Partnership is required to maintain the following financial covenants: (i) current assets to current liabilities of at least 1.0 to 1.0 at all times; (ii) senior secured net debt to consolidated Adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 4.5 to 1.0 if the Adjusted EBITDA of the Partnership's midstream operations equals or exceeds one-third of total Adjusted EBITDA or 4.0 to 1.0 if the Adjusted EBITDA of the Partnership's midstream operations is less than one-third of total Adjusted EBITDA; and (iii) minimum interest coverage ratio of at least 2.5 to 1.0 if the Adjusted EBITDA of the Partnership's midstream operations is greater than one-third of the Partnership's total Adjusted EBITDA.

The Partnership has the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Amended Credit Agreement, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Amended Credit Agreement exceed 90% of the borrowing base attributable to the Partnership's oil and gas properties, after giving effect to the proposed distribution. The Partnership's available cash is reduced by any cash reserves established by the board of directors of the General Partner for the proper conduct of the Partnership's business and the payment of fees and expenses.

We monitor compliance with the covenants of the Credit Agreement on an ongoing basis. As of September 30, 2015, the Partnership's ratio of total net debt to Adjusted EBITDA, calculated in accordance with the terms of the Credit Agreement in effect as of September 30, 2015, exceeded 4.5 to 1.0. However, as a result of the Amended Credit Agreement, we are not required to provide a compliance certificate for the quarter ended September 30, 2015 as part of the normal quarterly compliance materials submitted to our lenders. As a result, the Partnership was deemed to be in compliance with its covenants as of September 30, 2015 and currently forecasts that its ratio of total net debt to Adjusted EBITDA will not exceed 4.5 to 1.0 for the next twelve months.

Debt Issuance Costs

As of September 30, 2015, our unamortized debt issuance costs were $1.6 million. These costs are amortized to interest expense in our consolidated statement of operations over the life of our Credit Agreement. At December 31, 2014, our unamortized debt issuance costs were $0.7 million.

8. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation (“ARO”) in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost (“ARC”) is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities. Subsequently,

Table of Contents

the ARC is depreciated using a systematic and rational method over the asset's useful life. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells, and decommissioning of oil and natural gas gathering and other facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas property balance.

The changes in the ARO for the nine months ended September 30, 2015 and the year ended December 31, 2014 were as follows (in thousands):

	September 30, 2015	December 31, 2014
Asset retirement obligation, beginning balance	$ 17,031	$ 9,513
Liabilities added from acquisitions	877	80
Liabilities added from drilling	—	59
Sold	(59)	—
Revisions to cost estimates	—	6,780
Settlements	(38)	(5)
Accretion expense	782	604
Asset retirement obligation, ending balance	$ 18,593	$ 17,031

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for AROs. As of September 30, 2015 and December 31, 2014, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs.

9. COMMITMENTS AND CONTINGENCIES

We did not have any material commitments and contingencies as of September 30, 2015.

10. RELATED PARTY TRANSACTIONS

Unit Ownership

As of September 30, 2015, a subsidiary of SN owned 105,263 common units, or 3.3% of our common units. As a result of the Western Catarina Midstream acquisition in October 2015, we repurchased all of the common units previously held by a subsidiary of SN.

Sanchez-Related Agreements

The Partnership and the Manager are parties to the Services Agreement pursuant to which the Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. Compensation for services provided under the Services Agreement consists of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) a

$1,000,000 administrative fee, which was paid during 2014, (iii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iv) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Each of these fees, not including the reimbursement of costs, will be paid in cash unless the Manager elects for such fee to be paid in our equity.

The Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless both the Manager and the Company provide notice to terminate the agreement. During the nine months ended September 30, 2015, we paid $5.3 million to the Manager under the Services Agreement.

Table of Contents

Additionally, as of September 30, 2015 and December 31, 2014, the Partnership had a net receivable from related parties of $0.7 million and $1.0 million, respectively, which are included in “Accounts receivable – related entities” in the condensed consolidated balance sheets. The net receivables as of September 30, 2015 and December 31, 2014 consist primarily of revenues receivable from oil and natural gas production, offset by costs associated with that production and obligations for general and administrative costs.

On May 8, 2014, the Company and SOG entered into a Contract Operating Agreement, the Company, the Manager and SOG entered into a Transition Agreement, and the Company, SOG and certain subsidiaries of the Company entered into a Geophysical Seismic Data Use License Agreement (the “License Agreement”). For further discussion of these agreements, refer to our Annual Report on Form 10-K for the year ended December 31, 2014.

On March 31, 2015, the Partnership and SN entered into a Purchase and Sale Agreement for the acquisition of the Eagle Ford properties for a purchase price of $85 million. See further discussion of the transaction in Note 3, “Acquisitions and Divestitures.”

11. UNIT-BASED COMPENSATION

Prior to our conversion to a Delaware limited partnership on March 6, 2015, we granted restricted common unit awards to certain employees in Texas under the 2009 Omnibus Incentive Compensation Plan (the “Omnibus Plan”). The Omnibus Plan provided for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Additionally, prior to March 6, 2015, we granted restricted common unit awards to certain field employees in Kansas and Oklahoma and to certain employees in Texas under our previous Long-Term Incentive Plan (the “Previous LTIP”).

After the conversion to a limited partnership, both the Omnibus Plan and the Previous LTIP had no outstanding units remaining. Effective March 6, 2015, the Omnibus Plan was amended and restated and renamed the Sanchez Production Partners LP Long-Term Incentive Plan (the “LTIP”). Restricted unit activity under the Omnibus Plan, the Previous LTIP, and the LTIP during the period, after adjusting for the reverse split, is presented in the following table:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2014	10,082	$ 31.10
Granted	137,257	17.07
Vested	(87,872)	18.68
Returned/Cancelled	(33,826)	17.33
Outstanding at September 30, 2015	25,641	$ 16.50

During the nine months ended September 30, 2015, the Partnership issued 346,925 restricted common units (34,693 restricted common units after adjusting for reverse unit split) pursuant to the LTIP to the directors of the Partnership’s general partner that vested immediately on the date of the grant. The unit based compensation expense for the awards were based on their grant date fair values. In March 2015, officers were granted a total of 1,025,641 restricted common units (102,564 restricted common units after adjusting for the reverse unit split) that were due upon request, of which 769,231 restricted common units (76,923 restricted common units after adjusting for reverse unit split) were vested and delivered at the request of the officers, net of 322,692 restricted common units (32,269 restricted common units after adjusting for reverse unit split) that were returned to the plan for settlement of taxes associated with the vesting.

The remaining unvested units as of September 30, 2015 belong to one employee of a subsidiary of the Partnership and are due upon request. As such, we have accelerated the recognition of the expense associated with these awards into the nine months ended September 30, 2015.

Table of Contents

12. DISTRIBUTIONS TO UNITHOLDERS

Beginning in June 2009, we suspended our quarterly distributions to unitholders. For each of the quarterly periods since June 2009, we were restricted from paying distributions to unitholders as we had no available cash (taking into account the cash reserves set by our board for the proper conduct of our business) from which to pay distributions.

13. MEMBERS' EQUITY/PARTNERS' CAPITAL

Outstanding Units

As of September 30, 2015, we had 11,130,855 Class A Preferred Units outstanding and 3,149,693 common units outstanding, which included 25,641 unvested restricted common units issued under the LTIP.

Conversion

The Company's board of managers approved a Plan of Conversion (the "Conversion") providing for the Conversion of the Company from a limited liability company formed under the laws of the State of Delaware into Sanchez LP, a limited partnership formed under the laws of the State of Delaware. This plan was approved by the vote of the unitholders of the Company on March 6, 2015. After the Conversion, all of the rights, privileges and obligations of the Company prior to the Conversion were transferred and are now held by the Partnership. The Conversion converted each outstanding common unit of the Company into one common unit of the Partnership. The outstanding Class A units of the Company were converted into common units of the Partnership in a number equal to 2% of the Partnership's common units outstanding immediately after the Conversion (after taking into account the conversion of such Class A units), and the outstanding Class Z unit of the Company was cancelled. In addition, a non-economic general partner interest in the Partnership was issued to our general partner, and the incentive distribution rights of the Partnership were issued to the Manager.

Common Unit Issuances

On August 3, 2015, the Partnership effected a 1-for-10 reverse split on its common units, pursuant to which common unitholders received one common unit for every ten common units held at the close of trading on August 3, 2015. All fractional units created by the reverse split were rounded to the nearest whole unit. Each unitholder received at least one unit. Post-split units of the Partnership began trading on August 4, 2015. Immediately prior to the reverse unit split, there were 31,495,506 common units of the Partnership issued and outstanding, with a per unit closing trading price on the NYSE MKT on August 3, 2015 of $1.55. Immediately after the reverse unit split, the number of issued and outstanding common units of the Partnership decreased to 3,149,551, not inclusive of shares required by DTCC due to the rounding up of fractional shares at the beneficial level, and the per unit opening trading price on the NYSE MKT.

Preferred Unit Issuance

Class A Preferred Unit Offerings: On March 31, 2015, the Partnership entered into a Class A Preferred Unit Purchase Agreement (the "Preferred Unit Purchase Agreement") with the purchasers named on Schedule A thereto (collectively, the "Purchasers"), pursuant to which the Partnership sold, and the Purchasers purchased, 10,625,000 of the Partnership's newly created Class A Preferred Units (the "Class A Preferred Units") in a privately negotiated transaction (the "Private Placement") for an aggregate cash purchase price of $1.60 per Class A Preferred Unit resulting in gross proceeds to the Partnership of $17 million. The Partnership used the net proceeds from this transaction, together with common units issued to SN, borrowings under the Credit Agreement, and available cash on hand, to pay the consideration in the Eagle Ford acquisition.

Additionally, on April 15, 2015, the Partnership entered into a Class A Preferred Unit Purchase Agreement (the "April Preferred Unit Purchase Agreement") with the purchasers named on Schedule A thereto (collectively, the "April Purchasers"), pursuant to which the Partnership sold, and the April Purchasers purchased, 234,375 of the Partnership's Class A Preferred Units in a privately negotiated transaction for an aggregate cash purchase price of $1.60 per Class A Preferred Unit resulting in gross proceeds to the Partnership of $375,000. The Partnership used the proceeds for general working capital purposes.

Commencing with the three months ended June 30, 2015 and through the date on which the Class A Preferred Units are converted into common units, the holders of the Class A Preferred Units shall be entitled to receive distributions. For the three months ended June 30, 2015, through and including the three months ending June 30, 2016, the distributions will be paid in kind with additional Class A

Table of Contents

Preferred Units; thereafter, distributions will be paid in-kind or in cash at the discretion of the board of directors of our general partner. For the first year after the issuance date, the distribution rate will be 10% per annum, or 2.5% per quarter; for the second year after the issuance date, the distribution rate will be 11.5% per annum, or 2.875% per quarter; and thereafter, the distribution rate will be 12.5% per annum, or 3.125% per quarter. Distributions will be made on or about the last day of each of February, May, August and November following the end of each quarter commencing with the three months ended June 30, 2015.

On August 10, 2015, the board of directors of our general partner declared a distribution to holders of Class A Preferred Units as of August 14, 2015 to be paid in kind for the three months ended June 30, 2015. This distribution to the holders was made on August 31, 2015.

Earnings per Unit

For the period prior to our conversion, the basic net income per unit was computed from the two-class method by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocated net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) was allocated to each class in proportion to the class weighted average number of units outstanding for the period, as compared to the weighted average number of units for all classes for the period.

Post conversion, net income (loss) per common unit for the period is based on any distributions that are made to the unitholders (common units) plus an allocation of undistributed net income based on provisions of the partnership agreement, divided by the weighted average number of common units outstanding. The two-class method dictates that net income for a period be reduced by the amount of distributions and that any residual amount representing undistributed net income be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income as if all of the net income for the period had been distributed in accordance with the partnership agreement. Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of determining net income per unit. Undistributed income is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units based on provisions of the partnership agreement. Undistributed losses are not allocated to unvested restricted unit awards as they do not participate in net losses. Distributions declared and paid in the period are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

Our general partner does not have an economic interest in the Partnership and, therefore, does not participate in the Partnership's net income.

Table of Contents

The following table presents the weighted average basic and diluted units outstanding for the periods indicated:

	March 6 - September 30 2015	January 1 - March 6 2015	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014
Class A units - Basic	—	484,505	—	484,505
Class B Common units - Basic	—	28,791,626	—	28,552,568
Common units - Basic	31,036,075	—	31,240,038	—
Weighted Average basic units prior to reverse split	31,036,075	29,276,131	31,240,038	29,037,073
Adjustment for reverse split	(27,932,467)	(26,348,518)	(28,116,034)	(26,133,366)
Weighted Average basic units after reverse split	3,103,608	2,927,613	3,124,004	2,903,707
Class A units - Diluted	—	484,505	—	484,505
Class B Common units - Diluted	—	28,791,626	—	28,660,878
Common units - Diluted	31,036,075	—	140,748,557	—
Weighted Average diluted units prior to reverse split	31,036,075	29,276,131	140,748,557	29,145,383
Adjustment for reverse split	(27,932,467)	(26,348,518)	(126,673,701)	(26,230,846)
Weighted Average diluted units after reverse split	3,103,608	2,927,613	14,074,856	2,914,537

At September 30, 2015, we had 25,641 common units that were restricted unvested common units granted and outstanding. No losses were allocated to participating restricted unvested units because such securities do not have a contractual obligation to share in the Partnership's losses.

The following table presents our basic and diluted loss per unit for the period from January 1, 2015 to March 6, 2015 (the date of conversion to a limited partnership) (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Assumed net loss to be allocated January 1 - March 6	$ (923)	$ (18)	$ (905)
Basic and diluted loss per unit prior to reverse split		$ (0.04)	$ (0.03)
Basic and diluted loss per unit after reverse split		$ (0.38)	$ (0.31)

The following table presents our basic and diluted loss per unit for the period from March 6, 2015 through September 30, 2015 (the period after conversion to a limited partnership) (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss attributable to common unitholders to be allocated March 6 - September 30	$ (92,578)	$ (92,578)
Basic and diluted loss per unit prior to reverse split		$ (2.98)
Basic and diluted loss per unit after reverse split		$ (29.83)

Net loss per unit increased significantly for the period from March 6, 2015 through September 30, 2015 as compared to the period from January 1, 2015 through March 5, 2015 as it included non-cash impairment charges of $84.7 million. There was no impairment charge recorded for the period from January 1, 2015 through March 5, 2015.

Table of Contents

The following table presents our basic and diluted income per unit for the three months ended September 30, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Assumed net income to be allocated	$ 5,655	$ 113	$ 5,542
Basic and diluted income per unit prior to reverse split		$ 0.23	$ 0.19
Basic and diluted income per unit after reverse split		$ 2.33	$ 1.93

The following table presents our basic and diluted loss per unit for the nine months ended September 30, 2014 (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Assumed net loss to be allocated	$ (2,295)	$ (46)	$ (2,249)
Basic and diluted loss per unit prior to reverse split		$ (0.05)	$ (0.08)
Basic and diluted loss per unit after reverse split		$ (0.54)	$ (0.79)

14. SUBSEQUENT EVENTS

On October 14, 2015, we completed the Western Catarina Midstream acquisition for a purchase price of $345.8 million, subject to normal and customary closing adjustments. The purchase price was funded at closing with net proceeds from the sale of Class B Preferred Units to Stonepeak, a private equity firm that focuses on the infrastructure space, and available cash. In connection with the issuance of the Class B Preferred Units, Stonepeak has received two seats on the board of directors of SPP's general partner and has appointed Luke Taylor and Jack Howell, each an employee of Stonepeak, to fill those seats. Additionally, as a result of the Western Catarina Midstream acquisition, we repurchased all of the common units previously held by a subsidiary of SN.

On October 14, 2015, in conjunction with the closing of the Western Catarina Midstream acquisition, the Partnership entered into the Amended Credit Agreement. Pursuant to the amendment, the borrowing base under the Credit Facility increased from $110 million to $200 million, excluding the value of the Partnership's Oklahoma and Kansas assets. Debt outstanding as of the date of the amendments was unchanged at $106 million. As a result of the amendment, which resulted in lower utilization of the borrowing base, the interest rate paid by the Partnership on the debt outstanding decreased by 0.50%. See further discussion in Note 7, "Long-Term Debt."

On November 10, 2015, the board of directors of our general partner declared a distribution to holders of Class A Preferred Units as of November 16, 2015 to be paid in kind and distributed to the holders on November 30, 2015.

On November 10, 2015, the board of directors of our general partner declared a distribution of $0.40 per unit to holders of common units as of November 16, 2015 to be paid on November 30, 2015.

On November 10, 2015, the board of directors of the Partnership's general partner approved a $10 million common unit repurchase plan (the "Unit Repurchase Plan"). The repurchases will be funded from cash on hand or available borrowings. The Unit Repurchase Plan may be suspended or discontinued at any time without prior notice.

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 financial statements and the summary of significant accounting policies and notes included herein and in our most recent Annual Report on Form 10-K.

Overview

Sanchez Production Partners LP, a Delaware limited partnership ("SPP", "we", "us", "our" or the "Partnership"), is a publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy production assets. We have entered into a shared services agreement (the "Services Agreement") with the sole member of our general partner (the "Manager") pursuant to which the Manager provides services that the we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. Our common units are currently listed on the NYSE MKT under the symbol "SPP."

Historically, our operations have consisted of the exploration and production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale from Sanchez Energy Corporation ("SN") and entered into a 15-year gathering and processing agreement with SN. We have also commenced a process to sell our oil and gas properties in the Mid-Continent region.

As a result of the acquisition of midstream assets from SN and the proposed disposition of our oil and gas properties located in the Mid-Continent region, our historical financial statements (including those in this Form 10-Q) will differ substantially from our future financial statements beginning with the quarter ending December 31, 2015 principally because a significant portion of our revenues will come from the long-term, fee-based gathering and processing agreement with SN rather than from oil and natural gas production.

Our primary business objective is to create long-term value and to generate stable cash flows that allow us to make and grow distributions over time. We plan to achieve our objective by executing our business strategy, which is to:

- Conduct a sales process to evaluate and pursue the possible divestiture of our Mid-Continent assets in 2015;
- Align our asset base, interests and operations with our sponsor, Sanchez Oil & Gas Corporation;
- Grow our business by acquiring cash producing assets involved in production, gathering and processing activities with minimal maintenance capital requirements and low overhead; and
- Reduce the volatility in our cash flows resulting from changes in oil and natural gas commodity prices and interest rates through efficient hedging programs.

Unless the context requires otherwise, any reference in this Quarterly Report on Form 10-Q to "Sanchez Production Partners," "we," "our," "us," "SPP," or the "Partnership" means Sanchez Production Partners LP and its subsidiaries, while references to the "Company" are to Sanchez Production Partners LLC.

How We Evaluate our Operations

We evaluate our business on the basis of the following key measures:

- our throughput volumes on the gathering system upon acquiring those assets;
- our operating expenses; and
- our Adjusted EBITDA.

24

Table of Contents

Throughput Volumes

Upon acquisition of the midstream assets from SN, our management began to analyze our performance based on the aggregate amount of throughput volumes on the gathering system. We must connect additional wells or well pads within the dedicated areas in order to maintain or increase throughput volumes on the gathering system. Our success in connecting additional wells is impacted by successful drilling activity by SN on the acreage dedicated to the gathering system, our ability to secure volumes from SN from new wells drilled on non-dedicated acreage, our ability to attract hydrocarbon volumes currently gathered by our competitors and our ability to cost-effectively construct or acquire new infrastructure.

Operating Expenses

Our management seeks to maximize the Adjusted EBITDA in part by minimizing operating expenses. These expenses are or will be comprised primarily of field operating costs (which lease operating expenses, labor, vehicle, supervision, transportation, minor maintenance, tools and supplies expenses, among other items), compression expense, ad valorem taxes and other operating costs, some of which will be independent of our oil and gas production or the throughput volumes on the gathering system but fluctuate depending on the scale of our operations during a specific period.

Non-GAAP Financial Measures—Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) adjusted by:

- interest (income) expense, net which includes:
- interest expense
- interest expense net (gain) loss on interest rate derivative contracts
- interest (income)
- income tax expense (benefit);
- depreciation, depletion and amortization;
- asset impairments;
- accretion expense;
- (gain) loss on sale of assets;
- (gain) loss from equity investment;
- unit-based compensation programs; and
- (gain) loss on mark-to-market activities.

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any cash reserves by the board of directors of our general partner) the distributions we would expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support a quarterly distribution or any increase in our quarterly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts, our lenders and others to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

We believe that the presentation of Adjusted EBITDA provides useful information to investors in assessing our financial condition and results of operations. The GAAP measures most directly comparable to Adjusted EBITDA is net income and net cash provided by operating activities. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income or net cash provided by operating activities. Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income and net cash provided by operating activities. Adjusted EBITDA should be

Table of Contents

considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

The following table presents a reconciliation of net income (loss) to Adjusted EBITDA, our most directly comparable U.S. GAAP performance measure, for each of the periods presented (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$ 7,795	$ 5,655	$ (92,532)	$ (2,295)
Adjusted by:				
Interest expense, net	672	511	2,440	1,569
Income tax expense	3	—	3	—
Depreciation, depletion and amortization	2,851	4,836	9,050	13,206
Asset impairments	937	43	84,664	237
Accretion expense	265	151	782	451
(Gain) loss on sale of assets	2	—	(111)	(23)
Unit-based compensation programs	75	86	2,463	1,216
(Gain) loss on mark-to-market activities	(12,305)	(5,594)	(1,671)	5,318
Adjusted EBITDA	$ 295	$ 5,688	$ 5,088	$ 19,679

Significant Operational Factors

- Production. Our production for the nine months ended September 30, 2015, was 1,093 MBOE, or an average of 4,002 BOE per day, compared with approximately 1,135 MBOE, or an average of 4,157 BOE per day, for the nine months ended September 30, 2014.
- Capital Expenditures. For the nine months ended September 30, 2015, we incurred approximately $84.2 million in capital expenditures, consisting of $83.4 million for the purchase of oil and natural gas properties in the Palmetto Field in Gonzales County, Texas (the "Eagle Ford properties" and such acquisition, the "Eagle Ford acquisition"), $1.3 million in development expenditures focused on properties in Texas and Louisiana and oil completions in the Cherokee Basin, offset primarily by proceeds from the sale of assets. These expenditures were funded with cash on hand, borrowings under our Credit Agreement and the issuance of common units as part of our consideration given in the Eagle Ford acquisition.
- Hedging Activities. All of our commodity derivatives are accounted for as mark-to-market activities. For the nine months ended September 30, 2015, the non-cash mark-to-market gain for our commodity derivatives was approximately $1.7 million, compared to a loss of $5.3 million for the same period in 2014.

Table of Contents

Results of Operations

Three months ended September 30, 2015 compared to three months ended September 30, 2014

The following table sets forth the selected financial and operating data for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		Variance	
	2015	2014		
Revenues:				
Natural gas sales at market price	$ 2,988	$ 5,590	$ (2,602)	(47) %
Natural gas hedge settlements	1,636	2,485	(849)	(34) %
Natural gas mark-to-market activities	716	282	434	154 %
Natural gas total	5,340	8,357	(3,017)	(36) %
Oil sales	4,531	6,498	(1,967)	(30) %
Oil hedge settlements	3,381	(408)	3,789	*
Oil mark-to-market activities	11,589	5,312	6,277	118 %
Oil total	19,501	11,402	8,099	71 %
Natural gas liquids sales	394	841	(447)	(53) %
Miscellaneous income	390	796	(406)	(51) %
Total revenues	25,625	21,396	4,229	20 %
Operating expenses:				
Lease operating expenses	5,194	5,296	(102)	(2) %
Cost of sales	139	404	(265)	(66) %
Production taxes	443	796	(353)	(44) %
General and administrative	7,376	3,780	3,596	95 %
Loss on sale of assets	2	—	2	*
Depreciation, depletion and amortization	2,851	4,836	(1,985)	(41) %
Asset impairments	937	43	894	*
Accretion expenses	265	151	114	75 %
Total operating expenses	17,207	15,306	1,901	12 %
Other expenses (income):				
Interest expense	672	511	161	32 %
Other expense (income)	(52)	(76)	24	(32) %
Total other expenses	620	435	185	43 %
Total expenses	17,827	15,741	2,086	13 %
Income before income taxes	7,798	5,655	2,143	38 %
Income tax expense	3	—	3	*
Net income	$ 7,795	$ 5,655	$ 2,140	38 %

* Not Meaningful

Table of Contents

	For the Three Months Ended September 30, 2015	2014	Variance	
Net production:				
Natural gas production (MMcf)	1,481	1,671	(190)	(11) %
Oil production (MBbl)	94	62	32	52 %
Natural gas liquids production (MBbl)	27	39	(12)	(31) %
Total production (BOE)	367	380	(13)	(3) %
Average daily production (BOE/d)	3,991	4,129	(138)	(3) %
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.12	$ 4.83	$ (1.71)	(35) %
Natural gas price per Mcf without hedge settlements	$ 2.02	$ 3.35	$ (1.33)	(40) %
Oil price per Bbl with hedge settlements	$ 84.56	$ 98.06	$ (13.50)	(14) %
Oil price per Bbl without hedge settlements	$ 48.43	$ 104.63	$ (56.20)	(54) %
Liquid price per Bbl without hedge settlements	$ 14.73	$ 21.40	$ (6.67)	(31) %
Total price per BOE with hedge settlements	$ 35.21	$ 39.50	$ (4.29)	(11) %
Total price per BOE without hedge settlements	$ 21.55	$ 34.03	$ (12.48)	(37) %
Average unit costs per BOE:				
Field operating expenses(a)	$ 15.35	$ 16.04	$ (0.69)	(4) %
Lease operating expenses	$ 14.15	$ 13.94	$ 0.21	1 %
Production taxes	$ 1.21	$ 2.10	$ (0.89)	(42) %
General and administrative expenses	$ 20.09	$ 9.95	$ 10.14	102 %
General and administrative expenses without unit-based compensation	$ 19.88	$ 9.72	$ 10.16	104 %
Depreciation, depletion and amortization	$ 7.76	$ 12.73	$ (4.97)	(39) %

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Production. For the three months ended September 30, 2015, 26% of our production was oil, 7% was NGLs and 67% was natural gas as compared to the three months ended September 30, 2014, where 17% of our production was oil, 10% was NGLs and 73% was natural gas. The amount of oil as a percentage of total production has increased during the three months ended September 30, 2015 due to the addition of production from the Eagle Ford properties acquired on March 31, 2015, which are significantly more weighted towards oil than our previous asset base. We expect this product mix to remain relatively consistent for the remainder of 2015.

Oil, NGL and natural gas sales. Unhedged oil sales decreased $2.0 million, or 30%, to $4.5 million for the three months ended September 30, 2015, compared to $6.5 million for the same period in 2014. NGL sales decreased $0.4 million, or 53%, to $0.4 million for the three months ended September 30, 2015, compared to $0.8 million for the same period in 2014. Unhedged natural gas sales decreased $2.6 million, or 47%, to $3.0 million for the three months ended September 30, 2015, compared to $5.6 million for the same period in 2014.

Including hedges and mark-to-market activities, our total revenue increased $4.2 million compared to the same period in 2014. This increase was the result of a $6.7 million increase in gains on mark-to-market activities, a $2.4 million increase related to higher sales volumes and a $2.9 million increase in settlements on our commodity derivatives, offset by a $7.4 million decrease attributable to lower market prices for all products. The remainder of the change between periods is related to a decrease of $0.4 million in miscellaneous income.

28

Table of Contents

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the three months ended September 30, 2014 to the three months ended September 30, 2015 (dollars in thousands):

	Q3 2015 Production Volume	Q3 2014 Production Volume	Production Volume Difference	Q3 2014 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (MMcf)	1,481	1,671	(190)	$ 3.35	$ (635)
Oil (MBbl)	94	62	32	$ 104.63	$ 3,292
Natural gas liquids (MBbl)	27	39	(12)	$ 21.40	$ (269)
Total oil equivalent (BOE)	367	380	(13)	$ 34.03	$ 2,388

	Q3 2015 Average Sales Price	Q3 2014 Average Sales Price	Average Sales Price Difference	Q3 2015 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 2.02	$ 3.35	$ (1.33)	1,481	$ (1,967)
Oil (MBbl)	$ 48.43	$ 104.63	$ (56.20)	94	$ (5,259)
Natural gas liquids (MBbl)	$ 14.73	$ 21.40	$ (6.67)	27	$ (178)
Total oil equivalent (BOE)	$ 21.55	$ 34.03	$ (12.48)	367	$ (7,404)

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the three months ended September 30, 2015 by $0.8 million.

Hedging activities. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and gas revenues. For the three months ended September 30, 2015, the non-cash mark-to-market gain was $12.3 million, compared to a gain of $5.6 million for the same period in 2014. The 2015 and 2014 non-cash gains were the result of the impact of higher future expected oil and natural gas prices on these derivative transactions. Cash settlements, including settlements receivable, for our commodity derivatives were $5.0 million for the three months ended September 30, 2015, compared to $2.1 million for the three months ended September 30, 2014.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expenses decreased $0.1 million, or 2%, to $5.2 million for the three months ended September 30, 2015, compared to $5.3 million for the same period in 2014.

For the three months ended September 30, 2015, per unit lease operating expenses were $14.15 per BOE compared to $13.94 per BOE for the same period in 2014. This increase is due to decreased production volumes combined with a consistent amount of lease operating expenses between the periods.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by the Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses increased $3.6 million, or 95%, to $7.4 million for the three months ended September 30, 2015, compared to $3.8 million for the same period in 2014. Our general and administrative expenses were higher in 2015 due to a $2.2 million increase in salaries and wages, $0.8 million in fees incurred for acquisitions, and $0.5 million in asset management fees paid to the Manager during the three months ended September 30, 2015 as compared to the same period in 2014. The remaining increase of $0.1 million is de minimis.

Our general and administrative expenses were $20.09 per BOE for the three months ended September 30, 2015, compared to $9.95 per BOE for the same period in 2014. Excluding unit-based compensation, our general and administrative costs were $19.88 per BOE for the three months ended September 30, 2015, compared to $9.72 per BOE for the same period in 2014. These increases resulted from the increased costs noted above as well as the decreased production between the periods.

Table of Contents

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as oil, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the three months ended September 30, 2015 was $2.8 million, or $7.76 per BOE, compared to $4.8 million, or $12.73 per BOE, for the same period in 2014. This overall decrease is the result of lower property values due to non-cash impairment charges previously recorded as well as increases to total proved reserves between the periods impacting the depletion rate. The overall expense decrease, combined with the decreased production between periods, resulted in the decrease in the per BOE expense. Our non-oil and gas properties are depreciated using the straight-line basis.

Impairment expense. For the three months ended September 30, 2015, we recorded non-cash charges of $0.9 million to impair the value of our oil and natural gas fields located in the Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties. During the same period in 2014, our non-cash impairment charges were less than $0.1 million to impair the value of our oil and natural gas fields in Texas and Louisiana. The impairment expense recorded during the three months ended September 30, 2015 resulted from decreases in expectations for oil and natural gas prices in the future as well as changes to our expected future production estimates in certain areas.

Interest expense. Interest expense for the three months ended September 30, 2015 increased $0.2 million, or 32%, to $0.7 million, compared to $0.5 million for the same period in 2014. This increase was due to the increase in borrowings under our Credit Agreement to finance a portion of the Eagle Ford acquisition on March 31, 2015.

Table of Contents

Nine months ended September 30, 2015 compared to nine months ended September 30, 2014

The following table sets forth the selected financial and operating data for the periods indicated (dollars in thousands):

	For the Nine Months Ended September 30,		Variance	
	2015	2014		
Revenues:				
Natural gas sales at market price	$ 9,825	$ 20,359	$ (10,534)	(52) %
Natural gas hedge settlements	5,054	5,088	(34)	(1) %
Natural gas mark-to-market activities	(854)	(6,124)	5,270	(86) %
Natural gas total	14,025	19,323	(5,298)	(27) %
Oil sales	13,046	21,882	(8,836)	(40) %
Oil hedge settlements	9,533	(904)	10,437	*
Oil mark-to-market activities	2,525	806	1,719	213 %
Oil total	25,104	21,784	3,320	15 %
Natural gas liquids sales	1,280	1,690	(410)	(24) %
Miscellaneous income	1,921	2,429	(508)	(21) %
Total revenues	42,330	45,226	(2,896)	(6) %
Operating expenses:				
Lease operating expenses	15,452	15,598	(146)	(1) %
Cost of sales	469	1,198	(729)	(61) %
Production taxes	1,396	2,563	(1,167)	(46) %
General and administrative	20,669	12,942	7,727	60 %
Gain on sale of assets	(111)	(23)	(88)	*
Depreciation, depletion and amortization	9,050	13,206	(4,156)	(31) %
Asset impairments	84,664	237	84,427	*
Accretion expenses	782	451	331	73 %
Total operating expenses	132,371	46,172	86,199	187 %
Other expenses (income):				
Interest expense	2,440	1,569	871	56 %
Other (income) expense	48	(220)	268	(122) %
Total other expenses	2,488	1,349	1,139	84 %
Total expenses	134,859	47,521	87,338	184 %
Loss before income taxes	(92,529)	(2,295)	(90,234)	*
Income tax expense	3	—	3	*
Net loss	$ (92,532)	$ (2,295)	$ (90,237)	*

* Not Meaningful

Table of Contents

	For the Nine Months Ended September 30, 2015	2014	Variance	
Net production:				
Natural gas production (MMcf)	4,605	5,087	(482)	(9) %
Oil production (MBbl)	250	216	34	16 %
Natural gas liquids production (MBbl)	75	71	4	6 %
Total production (BOE)	1,093	1,135	(42)	(4) %
Average daily production (BOE/d)	4,002	4,157	(155)	(4) %
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.23	$ 5.00	$ (1.77)	(35)%
Natural gas price per Mcf without hedge settlements	$ 2.13	$ 4.00	$ (1.87)	(47)%
Oil price per Bbl with hedge settlements	$ 90.43	$ 97.01	$ (6.58)	(7) %
Oil price per Bbl without hedge settlements	$ 52.25	$ 101.19	$ (48.94)	(48)%
Liquid price per Bbl without hedge settlements	$ 17.03	$ 23.86	$ (6.83)	(29)%
Total price per BOE with hedge settlements	$ 35.46	$ 42.40	$ (6.94)	(16)%
Total price per BOE without hedge settlements	$ 22.11	$ 38.71	$ (16.60)	(43)%
Average unit costs per BOE:				
Field operating expenses(a)	$ 15.42	$ 16.00	$ (0.58)	(4) %
Lease operating expenses	$ 14.14	$ 13.74	$ 0.40	3 %
Production taxes	$ 1.28	$ 2.26	$ (0.98)	(43)%
General and administrative expenses	$ 18.92	$ 11.40	$ 7.52	66 %
General and administrative expenses without unit-based compensation	$ 16.67	$ 10.33	$ 6.34	61 %
Depreciation, depletion and amortization	$ 8.28	$ 11.64	$ (3.36)	(29)%

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Production: For the nine months ended September 30, 2015, 23% of our production was oil, 7% was NGLs and 70% was natural gas as compared to the nine months ended September 30, 2014, where 19% of our production was oil, 6% was NGLs and 75% was natural gas. The amount of oil as a percentage of total production has increased during the nine months ended September 30, 2015 due to the addition of production from the Eagle Ford properties acquired on March 31, 2015, which are significantly more weighted towards oil than our previous asset base. We expect this product mix to remain relatively consistent for the remainder of 2015.

Oil, NGL and natural gas sales. Unhedged oil sales decreased $8.8 million, or 40%, to $13.1 million for the nine months ended September 30, 2015, compared to $21.9 million for the same period in 2014. NGL sales decreased $0.4 million, or 24%, to $1.3 million for the nine months ended September 30, 2015, compared to $1.7 million for the same period in 2014. Unhedged natural gas sales decreased approximately $10.5 million, or 52%, to $9.8 million for the nine months ended September 30, 2015, compared to $20.3 million for the same period in 2014.

Including hedges and mark-to-market activities, our total revenue decreased $2.9 million, compared to the same period in 2014. This decrease was the result of a $21.3 million decrease attributable to lower market prices for all products offset by $1.5 million increase related to higher sales volumes, a $7.0 million increase in gains on mark-to-market activities and a $10.4 million increase in settlements on our commodity derivatives. The remainder of the decrease is related to a decrease between the periods of $0.5 million in miscellaneous income.

32

Table of Contents

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the nine months ended September 30, 2014 to the nine months ended September 30, 2015 (dollars in thousands):

	YTD 2015 Production Volume	YTD 2014 Production Volume	Production Volume Difference	YTD 2014 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (MMcf)	4,605	5,087	(482)	$ 4.00	$ (1,929)
Oil (MBbl)	250	216	34	$ 101.19	$ 3,385
Natural gas liquids (MBbl)	75	71	4	$ 23.86	$ 103
Total oil equivalent (BOE)	1,093	1,135	(42)	$ 38.71	$ 1,559

	YTD 2015 Average Sales Price	YTD 2014 Average Sales Price	Average Sales Price Difference	YTD 2015 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 2.13	$ 4.00	$ (1.87)	4,605	$ (8,605)
Oil (MBbl)	$ 52.25	$ 101.19	$ (48.94)	250	$ (12,221)
Natural gas liquids (MBbl)	$ 17.03	$ 23.86	$ (6.82)	75	$ (513)
Total oil equivalent (BOE)	$ 22.11	$ 38.71	$ (16.60)	1,093	$ (21,339)

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the nine months ended September 30, 2015 by $2.4 million.

Hedging activities. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and gas revenues. For the nine months ended September 30, 2015, the non-cash mark-to-market gains were $1.7 million, compared to a loss of $5.3 million for the same period in 2014. Cash settlements, including settlements receivable, for our commodity derivatives were $14.6 million for the nine months ended September 30, 2015, compared to $4.2 million for the nine months ended September 30, 2014.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expenses decreased $0.1 million, or 1%, to $15.5 million for the nine months ended September 30, 2015, compared to $15.6 million for the same period in 2014.

On a per unit basis, lease operating expenses were $14.14 per BOE compared to $13.74 per BOE for the same period in 2014. This increase is due to relatively consistent expense as noted above with a decrease in production volumes between the periods.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by the Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses increased $7.7 million, or 60%, to $20.7 million for the nine months ended September 30, 2015, compared to $13.0

million for the same period in 2014. Our general and administrative expenses were higher in 2015 due to a $2.5 million increase in labor and incentive compensation costs relating to severance costs associated with the departure of our former Chief Executive Officer, a $2.2 million increase in salaries and wages , a $1.2 million increase in unit-based compensation, $1.2 million in fees incurred for acquisitions, and $1.0 million increase in legal and professional services, mostly resulting from the conversion to a limited partnership during 2015. These increases were offset by a reduction in costs for the board of directors of our general partner of $0.4 million between the periods.

Our general and administrative expenses were $18.92 per BOE for the nine months ended September 30, 2015, compared to $11.40 per BOE for the same period in 2014. Excluding unit-based compensation, our general and administrative costs were $16.67 per BOE for the nine months ended September 30, 2015, compared to $10.33 per BOE for the same period in 2014.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the

Table of Contents

successful efforts method of accounting. Assuming other variables remain constant, as oil, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the nine months ended September 30, 2015 was $9.0 million, or $8.28 per BOE, compared to $13.2 million, or $11.64 per BOE, for the same period in 2014. This overall decrease is the result of lower property values due to non-cash impairment charges previously recorded as well as increases to total proved reserves between the periods impacting the depletion rate. Our non-oil and gas properties are depreciated using the straight-line basis.

Impairment expense. For the nine months ended September 30, 2015, we recorded non-cash charges of $84.7 million to impair the value of our Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties. During the same period in 2014 our non-cash impairment charges were approximately $0.2 million to impair the value of our oil and natural gas fields in Texas and Louisiana. The impairment expense recorded during the nine months ended September 30, 2015 resulted from decreases in expectations for oil and natural gas prices in the future as well as changes to our expected future production estimates in certain areas.

Interest expense. Interest expense for the nine months ended September 30, 2015 increased $0.9 million, or 56%, to $2.5 million, compared to $1.6 million for the same period in 2014. This increase was due in part to the write off of debt issuance costs which resulted from the modification of our Credit Agreement in March 2015, and the removal of one of the banks from our lending syndicate. The remainder of the increase is the result of increased borrowings under our Credit Agreement to finance a portion of the Eagle Ford acquisition on March 31, 2015.

The interest rate on our outstanding debt was approximately 3.0% and 3.2% as of September 30, 2015 and 2014, respectively.

Liquidity and Capital Resources

As of September 30, 2015, we had approximately $9.0 million in cash and cash equivalents, $0.6 million in restricted cash, and $4 million available under the $110 million borrowing base of our Credit Agreement in effect on such date.

On October 14, 2015, in conjunction with the Western Catarina Midstream acquisition, the Partnership entered into the Joinder, Assignment and Second Amendment to the Credit Agreement with a syndicate of nine lenders (the “Amended Credit Agreement”). Pursuant to the Amended Credit Agreement, the borrowing base under the credit facility increased from $110 million to $200 million, excluding the value of the Partnership’s Oklahoma and Kansas assets. As a result, the amount available for borrowing under the Credit Agreement increased from $4 million to $94 million on October 14, 2015.

Our capital expenditures during the nine months ended September 30, 2015 were funded with cash on hand, borrowings under our Credit Agreement, a private placement of Class A Preferred Units and the issuance of common units as part of our consideration given in the Eagle Ford acquisition. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our Credit Agreement and proceeds from the issuance of additional limited partner units. We expect that the combination of these capital resources will be adequate to meet our short-term working capital requirements, long-term capital expenditures program and expected quarterly cash distributions.

We intend to distribute at least the quarterly distribution of $0.40 per unit ($1.60 per unit on an annualized basis) on all of our common units to the extent we have sufficient cash after the establishment of cash reserves and the payment of our expenses. We expect that our future cash requirements relating to working capital, maintenance capital expenditures and quarterly cash distributions to our partners will be funded from cash flows internally generated from our operations. Our expansion capital expenditures will be funded by borrowings under our Credit Agreement or from potential capital market transactions. However, there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our current debt level, planned levels of capital expenditures, operating expenses or any cash distributions that we may make to unitholders.

As previously disclosed, we have engaged a financial advisor related to the possible sale of our Oklahoma and Kansas assets. As a result of this proposed sale, we anticipate minimal drilling activities in the Mid-Continent region during the remainder of 2015, which will reduce our capital expenditures for 2015 and result in a continued decline of our production during the remainder of 2015.

Table of Contents

Sources of Debt and Equity Financing

As of September 30, 2015, the borrowing base under our Credit Agreement was $110 million and we had $106 million of debt outstanding under the facility, leaving us with $4 million in unused borrowing capacity. As of October 14, 2015, the borrowing base under our Amended Credit Agreement was set at $200 million and we had $106 million of debt outstanding under the facility, leaving us with $94 million in unused borrowing capacity. Our Credit Agreement matures on March 31, 2020.

In May 2015, we executed an at-the-market facility that allows us to sell up to $18.6 million of common units, with any proceeds from such sales to be used for general limited partnership purposes. As of September 30, 2015, we had sold 28,700 common units (2,870 common units after adjusting for reverse unit split) for total net proceeds of less than $0.1 million. During 2015 we paid de minimis commissions to the sales agent in connection with the at-the-market facility.

Open Commodity Hedge Position

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. As of September 30, 2015, each of the financial institutions with whom we have entered into derivative contracts had an investment grade credit rating. All of our derivatives are currently collateralized by the assets securing our Credit Agreement and, therefore, we are not currently required to post cash collateral in connection with our hedging activities.

Net Cash Provided by Operations

We had net cash flows provided by operating activities for the nine months ended September 30, 2015 of $8.7 million, compared to net cash flow provided by operating activities of $12.7 million for the same period in 2014. This decrease was primarily related to lower average commodity prices between the periods.

One of the primary sources of variability in our cash flows from operating activities is fluctuations in commodity prices, the impact of which we mitigate by entering into commodity derivatives. Sales volumes also impact cash flow. Our cash flows from operating activities are also dependent on the costs related to continued operations and debt service. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program, acquisitions and successful execution of our hedging program. For additional information on our business plan, refer to "Outlook."

Net Cash Used in Investing Activities

We had net cash flows used in investing activities for the nine months ended September 30, 2015 of $82.2 million, which included $81.4 million provided as cash consideration paid in the Eagle Ford acquisition, as well as $0.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.0 million in development expenditures focused on properties in Texas and Louisiana, offset by $0.5 million in proceeds from the sale of assets during the period.

During the nine months ended September 30, 2014, our cash capital expenditures were $6.4 million, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $3.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.7 million in development expenditures focused on properties in Texas and Louisiana. We completed eight net wells and six net recompletions during the nine months ended September 30, 2014 and had no net well and net recompletion in progress at September 30, 2014.

Table of Contents

Net Cash Provided by (Used in) Financing Activities

Net cash flows provided by financing activities was $78.2 million for the nine months ended September 30, 2015, compared to $1.8 million used in financing activities for the same period in 2014. During the nine months ended September 30, 2015, we had borrowings under our Credit Agreement of $106.0 million, $42.5 million of which was paid to satisfy amounts due under the Second Amended and Restated Credit Agreement, which was refinanced on March 31, 2015. We received $17.4 million from the private placement of Class A Preferred Units during the period, while incurring $0.8 million in offering expenses. We also incurred $1.3 million in debt issuance costs associated with the modification of our Credit Agreement on March 31, 2015. We used $0.6 million to fund the cost of units tendered by employees for tax withholdings related to the vesting of units during the period.

Our net cash used by financing activities was $1.8 million for the nine months ended September 30, 2014. We had borrowings under our Credit Agreement of $5.8 million for working capital purposes and repayments of $4.5 million. We used $1.65 million to purchase the Class C and Class D interests from the owner thereof to settle litigation. We used $0.8 million for the payment of another litigation settlement of $6.5 million, which had been accrued at December 30, 2013, but was not paid until the second quarter of 2014. We used $0.4 million during the nine months ended September 30, 2014 to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

Off-Balance Sheet Arrangements

As of September 30, 2015, we had no off-balance sheet arrangements with third parties, and we maintained no debt obligations that contained provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through September 30, 2015, we have not suffered any significant losses with our counterparties as a result of non-performance.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions. The results of these estimates and assumptions form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements.

As of September 30, 2015, there were no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014, which was filed with the SEC on March 5, 2015. The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, revenue recognition and hedging activities. Please read Note 1 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

See Note 1 to our condensed consolidated financial statements included in this report for information on new accounting pronouncements.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

This section is not applicable to smaller reporting companies.

Item 4. Controls and Procedures

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, with SPP have been detected. These inherent limitations include error by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures

The Interim Chief Executive Officer and the Chief Financial Officer of the general partner of SPP have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of September 30, 2015 (the Evaluation Date). Based on such evaluation, the Interim Chief Executive Officer and the Chief Financial Officer have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed 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 and is accumulated and communicated to our management, including the Interim Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the three months ended September 30, 2015, there were no changes in SPP’s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, SPP’s internal control over financial reporting.

Table of Contents

Part II—Other Information

Item 1. Legal Proceedings

We did not have any material legal proceedings as of September 30, 2015.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in our Current Reports on Form 8-K that were filed with the SEC on October 14, 2015 and March 6, 2015, with the exception of those described below. An investment in our common units involves various risks. When considering an investment in us, careful consideration should be given to the risk factors described in such Form 8-K. These risks and uncertainties are not the only ones facing us, and there may be additional matters that are not known to us or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition or future results and, thus, the value of an investment in us.

Our common unitholders' share of our income will be taxable to them even if they do not receive any cash distributions from us.

Common unitholders are required to pay U.S. federal income and other taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income. We did not make any cash distributions to our common unitholders with respect to the year ended December 31, 2014 or the first two quarters of 2015.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by states and localities. If the Internal Revenue Service ("IRS") were to treat us as a corporation for U.S. federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state or local tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for U.S. federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for U.S. federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on our current operations, we believe that we satisfy the qualifying income requirement and will continue to be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate income tax rates, which is currently at a maximum marginal rate of 35%, and would likely pay state and local income tax at varying rates. Distributions to unitholders would generally be taxed as corporate distributions, and no income, gains, losses, deductions or credits would flow through to the unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders likely causing a substantial reduction in the value of our common units. In addition, recently enacted legislation applicable to partnership tax years beginning after 2017 would permit the IRS to assess and collect taxes resulting from partnership-level audits directly from us in the year in which the audit is completed.

At the state level, changes in current state law may subject us to additional entity-level taxation by individual states. Due to widespread state budget deficits and for other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may materially reduce the cash available for distribution to our unitholders.

Table of Contents

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution and the target distributions may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our limited partner interests may be modified by administrative, legislative or judicial interpretation at any time. For example, the Department of the Treasury and IRS have issued proposed regulations that, if finalized in their current form, would restrict the types of natural resource activities that generate qualifying income for publicly traded partnerships. We believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the proposed regulations. However, the proposed regulations could be changed before they are finalized and could take a position that is contrary to our interpretation of Section 7704 of the Internal Revenue Code of 1986, as amended. In addition, from time to time the Obama Administration and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would adversely affect publicly traded partnerships. One such Obama Administration budget proposal for fiscal year 2016 would, if enacted, tax publicly traded partnerships with "fossil fuels" activities as corporations for U.S. federal income tax purposes beginning in 2021. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could adversely affect an investment in our common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates ourselves using a methodology based on the market value of our common units as a means to determine the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. The Department of the Treasury and the IRS recently adopted final Treasury regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted. Certain publicly traded partnerships, including us, may but are not required to apply the conventions provided by the Treasury regulations. If the IRS were to challenge our proration method, our items of income, gain, loss and deduction could be reallocated among our unitholders.

Table of Contents

Forward-Looking Statements

This Quarterly Report on Form 10-Q contains “forward-looking statements” as defined by the SEC that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements may include discussions about our:

- business strategy;
- acquisition strategy;
- financial strategy;
- ability to make, maintain and grow distributions;
- the ability of our customers to meet their drilling and development plans on a timely basis or at all and perform under gathering and processing agreements;
- future operating results;
- future capital expenditures; and
- plans, objectives, expectations, forecasts, outlook and intentions.

All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 2. and other items within this Quarterly Report on Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “potential,” “pursue,” “target,” “continue,” the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors listed in the “Risk Factors” section and elsewhere in this Quarterly Report on Form 10-Q. The forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

During the three and nine months ended September 30, 2015, in connection with the quarterly distribution for the Class A Preferred Units, the Partnership issued the following additional Class A preferred units (“PIK Class A Units”) to the holders of the Class A Preferred Units (in thousands, except unit amounts):

Period	PIK Class A Units	Implied Fair Value	Date of Distribution
July 1, 2015 - July 31, 2015	—	$ —	—
August 1, 2015 - August 31, 2015	—	$ —	—
September 1, 2015 - September 30, 2015 (1)	271,480	$ 969	August 31, 2015 (1)

(1) Distribution was made with respect to the three months ended June 30, 2015. The board of directors of the Partnership's general partner authorized the issuance of 278,276 PIK Class A Units in November 2015 with respect to the three months ended September 30, 2015.

No proceeds were received as consideration for the issuance of the PIK Class A Units. The PIK Class A Units were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended. The Partnership gave notice to the holders of the Class A Preferred Units that the Partnership will convert all outstanding Class A Preferred Units (including PIK

Table of Contents

Class A Units) on March 31, 2016. For additional information regarding the Class A Preferred Units, see Note 13, "Members' Equity/Partners' Capital" to unaudited condensed consolidated financial statements included under Part I, Item 1 of this report.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

(a) The following documents are filed as a part of this Quarterly Report on Form 10-Q:
1.Financial Statements:

Condensed Consolidated Statements of Operations– Sanchez Production Partners LP and subsidiaries for the three and nine months ended September 30, 2015 and September 30, 2014

Condensed Consolidated Balance Sheets – Sanchez Production Partners LP and subsidiaries at September 30, 2015 and December 31, 2014

Condensed Consolidated Statements of Cash Flows – Sanchez Production Partners LP and subsidiaries for the nine months ended September 30, 2015 and September 30, 2014

Condensed Consolidated Statements of Changes in Members' Equity/Partners' Capital – Sanchez Production Partners LP and subsidiaries for the year ended December 31, 2014 and the nine months ended September 30, 2015

Notes to Condensed Consolidated Financial Statements

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
*31.1 —	Certification of Interim Chief Executive Officer of Sanchez Production Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2 —	Certification of Chief Financial Officer of Sanchez Production Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1 —	Certification of Interim Chief Executive Officer of Sanchez Production Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2 —	Certification of Chief Financial Officer of Sanchez Production Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS —	XBRL Instance Document
*101.SCH —	XBRL Schema Document
*101.CAL —	XBRL Calculation Linkbase Document
*101.LAB —	XBRL Label Linkbase Document
*101.PRE —	XBRL Presentation Linkbase Document
*101.DEF —	XBRL Definition Linkbase Document

*	Filed herewith

Table of Contents

SIGNATURES

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

	SANCHEZ PRODUCTION PARTNERS LP
	(REGISTRANT)
	BY: Sanchez Production Partners GP LLC, its general partner
Date: November 13, 2015	By /s/ Charles C. Ward Charles C. Ward Chief Financial Officer and Secretary