Sanchez Production Partners LP
Form 10-Q
August 14, 2015

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 June 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	(I.R.S. Employer

organization)	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 August 13, 2015: Approximately 3,149,551 units (subject to finalization of reverse split rounding).

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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 June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Revenues				
Natural gas sales	$ 3,642	$ 6,575	$ 10,216	$ 12,599
Oil and liquids sales	1,139	5,514	6,489	11,231
Total revenues	4,781	12,089	16,705	23,830
Expenses:				
Operating expenses:				
Lease operating expenses	5,358	5,182	10,258	10,302
Cost of sales	125	434	330	794
Production taxes	583	995	953	1,767
General and administrative	3,746	5,591	13,293	9,162
Gain on sale of assets	(54)	(16)	(113)	(23)
Depreciation, depletion and amortization	3,079	4,320	6,199	8,370
Asset impairments	862	45	83,727	194
Accretion expense	264	150	517	300
Total operating expenses	13,963	16,701	115,164	30,866
Other expenses (income):				
Interest expense	1,122	533	1,768	1,058
Other expense (income)	37	(134)	100	(144)
Total other expenses	1,159	399	1,868	914
Total expenses	15,122	17,100	117,032	31,780
Net loss	(10,341)	(5,011)	(100,327)	(7,950)
Less:				
Preferred unit paid-in-kind distributions	(524)	-	(524)	-
Net loss attributable to common unitholders	$ (10,865)	$ (5,011)	$ (100,851)	$ (7,950)
Loss per unit				
Net loss per unit prior to conversion (1)				
Class A units - Basic and diluted	$ -	$ (2.07)	$ (0.38)	$ (1.52)
Class B units - Basic and diluted	$ -	$ (1.73)	$ (0.31)	$ (2.76)

Weighted Average Units Outstanding prior to conversion (1)				
Class A units - Basic and diluted	-	48,451	48,451	104,664
Class B units - Basic and diluted	-	2,830,538	2,879,163	2,825,999
Net loss per unit after conversion (1)				
Common units - Basic and diluted	$ (3.49)	$ -	$ (32.37)	$ -
Weighted Average Units Outstanding after conversion (1)				
Common units - Basic and diluted	3,113,428	-	3,087,431	-

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

See accompanying notes to condensed consolidated financial statements.

SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	June 30, 2015 (unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 5,224	$ 4,238
Restricted cash	600	1,748
Accounts receivable	2,735	3,901
Accounts receivable - related entities	2,541	959
Prepaid expenses	1,375	1,783
Fair value of derivative instruments	11,434	14,671
Total current assets	23,909	27,300
Oil and natural gas properties and related equipment (successful efforts method)		
Oil and natural gas properties, equipment and facilities	732,827	651,493
Material and supplies	1,056	1,056
Less accumulated depreciation, depletion, amortization, and impairments	(606,607)	(517,239)
Oil and natural gas properties and equipment, net	127,276	135,310
Other assets		
Debt issuance costs	1,660	689
Fair value of derivative instruments	4,426	8,158
Other non-current assets	2,521	1,790
Total assets	$ 159,792	$ 173,247
LIABILITIES AND MEMBERS' EQUITY/PARTNERS' CAPITAL		
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 7,522	$ 5,759
Royalties payable	735	1,134
Fair value of derivative instruments	257	-
Total current liabilities	8,514	6,893
Other liabilities		
Asset retirement obligation	18,395	17,031
Long-term debt	106,000	42,500
Total other liabilities	124,395	59,531
Total liabilities	132,909	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 June 30, 2015 and December 31, 2014, respectively	-	1,930
Class B units, Zero and 2,879,258(1) units issued and outstanding as of June 30, 2015 and December 31, 2014, respectively	-	104,893

Class A preferred units, 10,859,375 and zero units issued and outstanding as of June 30, 2015 and December 31, 2014, respectively	14,566	-
Common units, 3,145,060(1) and zero units issued and outstanding as of June 30, 2015 and December 31, 2014, respectively	12,317	-
Total members' equity/partners' capital	26,883	106,823
Total liabilities and members' equity/partners' capital	$ 159,792	$ 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.

SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(Unaudited)

	Six Months Ended June 30, 2015	2014
Cash flows from operating activities:		
Net loss	$ (100,327)	$ (7,950)
Adjustments to reconcile net loss to cash provided by operating activities		
Depreciation, depletion and amortization	6,199	8,370
Asset impairments	83,727	194
Amortization of debt issuance costs	324	127
Accretion expense	517	300
Equity earnings in affiliate	48	(70)
Gain from disposition of property and equipment	(113)	(23)
Bad debt expense	122	112
Total mark-to-market losses on commodity derivative contracts	1,066	8,805
Cash mark-to-market settlements on commodity derivative contracts	8,950	2,107
Unit-based compensation programs	2,388	1,130
Changes in Operating Assets and Liabilities:		
(Increase) decrease in accounts receivable	1,721	(3,489)
Increase in accounts receivable - related entities	(1,582)	-
Decrease in prepaid expenses	408	1,272
(Increase) decrease in other assets	(981)	2
Increase (decrease) in accounts payable/accrued liabilities	2,788	(4,957)
Increase (decrease) in royalties payable	(399)	96
Net cash provided by operating activities	4,856	6,026
Cash flows from investing activities:		
Cash paid for acquisitions	(81,378)	(1,351)
Development of oil and natural gas properties	(1,056)	(3,819)
Proceeds from sale of assets	344	58
Distributions from equity affiliate	15	140
Net cash used in investing activities	(82,075)	(4,972)
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)	(157)
Debt issuance costs	(1,294)	(136)
Net cash provided by (used in) financing activities	78,205	(1,511)
Net increase (decrease) in cash and cash equivalents	986	(457)
Cash and cash equivalents, beginning of period	4,238	4,894
Cash and cash equivalents, end of period	$ 5,224	$ 4,437
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ (149)	$ (542)
Accrual for cancellation of Class A units	-	818
Acquisition of oil and natural gas properties in exchange for common units	2,000	-
Cash paid during the period for interest	(1,154)	(950)
Cash paid during the period for income taxes	(2)	(2)

See accompanying notes to condensed consolidated financial statements.

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/Ca
Members' Equity, December 31, 2013	161,502	$ 2,591	2,846,218	$ 96,314	-	$ -	-	$ -	$ 98,905
Units tendered by employees for tax withholding	-	-	(16,018)	(415)	-	-	-	-	(415)
Unit-based compensation programs	-	-	49,058	1,298	-	-	-	-	1,298
Cancellation of units	(113,051)	(851)	-	(1,617)	-	-	-	-	(2,468)
Net income	-	190	-	9,313	-	-	-	-	9,503
Members' Equity, December 31, 2014	48,451	$ 1,930	2,879,258	$ 104,893	-	$ -	-	$ -	$ 106,82
Units tendered by employees for tax withholding	-	-	(1,557)	(21)	-	-	-	-	(21)
Unit-based compensation programs	-	-	-	-	-	-	-	-	-
Net loss (January 1st - March 5th)	-	(18)	-	(905)	-	-	-	-	(923)
Members' Equity, March 5, 2015	48,451	$ 1,912	2,877,701	$ 103,967	-	$ -	-	$ -	$ 105,87

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)
Unit-based compensation programs	-	-	-	-	-	-	132,766	2,388	2,388
Private placement of Class A Preferred Units, net of offering costs of $810	-	-	-	-	10,859,375	16,565	-	-	16,565
Beneficial conversion feature of Class A preferred units	-	-	-	-	-	(2,523)	-	2,523	-
Common units issued for acquisition of properties	-	-	-	-	-	-	105,263	2,000	2,000
Issuance of common units	-	-	-	-			2,870	52	52
Preferred unit paid-in-kind distributions	-	-	-	-	-	524	-	(524)	-
Net loss (March 6th - June 30th)	-	-	-	-	-	-	-	(99,404)	(99,404)
Partners' Capital, June 30, 2015	-	$ -	-	$ -	10,859,375	$ 14,566	3,145,060	$ 12,317	$ 26,883

(1) Amounts adjusted for 1-for-10 reverse split completed August 3, 2015. See Note 13.
See accompanying notes to condensed consolidated financial statements.

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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 an oil a gas exploration and production limited partnership focused on the acquisition, development and production of oil and natural gas properties and other integrated assets. SPP completed its initial public offering on November 20, 2006, as Constellation Energy Partners LLC ("CEP" or the "Company"). In August 2013, Sanchez Energy Partners I, LP ("SEP I"), an affiliate of Sanchez Oil & Gas Corporation ("SOG"), contributed certain oil and natural gas properties in Texas and Louisiana to CEP in exchange for equity interests in CEP. On May 8, 2014, the Company and SP Holdings, LLC (the "Manager"), the sole member of our general partner, entered into a Shared Services Agreement (the "Services Agreement") pursuant to which the Manager agreed to provide 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. The Services Agreement became effective as of July 1, 2014. CEP's name was subsequently changed to Sanchez Production Partners LLC and 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."

SOG is a private company engaged in the management of oil and natural gas properties on behalf of its related companies, with whom it has various service agreements encompassing a wide range of activities, including, but not limited to, management, administrative and operational services. SEP I and SP Holdings, LLC are related to SOG through services agreements, and SOG owns a 0.5% general partner interest in SEP I. Our proved reserves are currently 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.

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 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 assets, total liabilities, total unitholders' equity, net income or net cash provided by or used in operating, investing or financing activities.

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.

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 June 30, 2015 and December 31, 2014.

Restricted Cash

Restricted cash, as of June 30, 2015 and December 31, 2014, of $0.6 million and $1.7 million, respectively, was being held in escrow. The balance as of June 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 June 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 Sanchez Energy Corporation (“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 (the “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 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	$ 73,024
Facilities	8,017
Fair value of hedges assumed	3,408

Fair value of assets acquired		84,449
Asset retirement obligations		(877)
Ad valorem tax liability		(194)
Fair value of net assets acquired	$	83,378

Pro Forma Operating Results

The following pro forma combined results for the three and six months ended June 30, 2015 and 2014 reflect the consolidated results of operations of the Partnership as if the Eagle Ford acquisition and related financing 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, and paid-in-kind units issued in connection with the preferred units.

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

• 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.

• 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues	$ 4,781	$ 25,715	$ 19,933	$ 50,728
Net income (loss) attributable to common unitholders	$ (10,865)	$ 2,818	$ (101,316)	$ 7,307
Net income (loss) per unit prior to conversion				
Class A units - Basic and diluted(1)	$ -	$ 1.16	$ (24.89)	$ 1.40
Class B units - Basic and diluted(1)	$ -	$ 0.94	$ (19.80)	$ 2.44
Net loss per unit after conversion				
Common units - Basic and diluted(1)	$ (3.61)	$ -	$ (13.65)	$ -

(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 Eagle Ford acquisition 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 six months ended June 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 and Six Months Ended

	June 30, 2015
Revenues	$ 3,328
Excess of revenues over direct operating expenses	$ 1,025

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.

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 tables summarize the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014 (in thousands):

	Fair Value Measurements at June 30, 2015				
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at June 30, 2015
Derivative assets	$ -	$ 16,121	$ -	$ (261)	$ 15,860
Derivative liabilities	-	(518)	-	261	(257)
Total net assets	$ -	$ 15,603	$ -	$ -	$ 15,603

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)	Significant 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 June 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.

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 June 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 June 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					118,097	$ 75.10	109,582	$ 75.64	227,679	$ 75.37
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
									1,294,244	

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					1,171,767	$ 4.16	1,118,334	$ 4.17	2,290,101	$ 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
									7,268,276	

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

	June 30, 2015	December 31, 2014
Beginning fair value of commodity derivatives	$ 22,829	$ 10,601
Net gains on crude oil derivatives	351	13,983
Net gains on natural gas derivatives	1,992	5,871
Net settlements on derivative contracts:		
Crude oil	(6,151)	69
Natural gas	(3,418)	(7,695)
Ending fair value of commodity derivatives	$ 15,603	$ 22,829

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

		Amount of Loss in Income			
	Location of Gain/(Loss)	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Derivative Type	in Income	2015	2014	2015	2014
Commodity – Mark-to-Market	Oil and natural gas sales	$ (5,897)	$ (4,730)	$ (1,064)	$ (8,805)

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with three 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 June 30, 2015 and December 31, 2014, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

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 June 30, 2015, the fair value of the hedges assumed resulted in a less than $0.1 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):

	June 30, 2015	December 31, 2014
Oil and natural gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 730,743	$ 649,432
Unproved property	1,583	1,560
Land	501	501
Total property costs	732,827	651,493
Materials and supplies	1,056	1,056
Total	733,883	652,549
Less: Accumulated depreciation, depletion, amortization and impairments	(606,607)	(517,239)
Oil and natural gas properties and equipment, net	$ 127,276	$ 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 six months ended June 30, 2015, we recorded non-cash charges of $0.9 million and $83.7 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 three and six months ended June 30, 2014, we recorded non-cash charges of $0.1 million and $0.2 million, respectively, to impair the value of our Texas and Louisiana properties. The current impairment was primarily the result of a decline in commodity prices. 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 six months ended June 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 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 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 June 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 4.0 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, 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, 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); (b) for the immediately following twenty-four month period, volumes of production hedged in any month may not exceed 90% of our projected monthly production from proved developed and producing reserves (or 85% of our projected monthly production from proved reserves); (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); 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.

We monitor compliance with the covenants of the Credit Agreement on an ongoing basis. As of June 30, 2015, the Partnership's ratio of total net debt to Adjusted EBITDA, calculated in accordance with the terms of the Credit Agreement, exceeded 4.0 to 1.0. On August 12, 2015, the Partnership and its lenders executed a waiver and amendment that allows for the exclusion of approximately $1.4 million in non-recurring general and administrative expenses recorded in the second quarter 2015 for purposes of calculating the ratio of total net debt to Adjusted EBITDA for the quarter ended June 30, 2015 and each subsequent compliance period in which June 30, 2015 results would factor into the calculation of total net debt to Adjusted EBITDA. As a result of the waiver and amendment, the Partnership was deemed to be in compliance with the total net debt to Adjusted EBITDA covenant as of June 30, 2015 and currently forecasts that its ratio of total net debt to Adjusted EBITDA will not exceed 4.0 to 1.0 for the next twelve months.

Debt Issuance Costs

As of June 30, 2015, our unamortized debt issuance costs were $1.7 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, 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 six months ended June 30, 2015 and the year ended December 31, 2014 were as follows (in thousands):

	June 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	(11)	-
Revisions to cost estimates	-	6,780
Settlements	(19)	(5)
Accretion expense	517	604
Asset retirement obligation, ending balance	$ 18,395	$ 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 June 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 June 30, 2015.

10. RELATED PARTY TRANSACTIONS

Unit Ownership

As of June 30, 2015, SEP I, an indirect subsidiary of SOG, owned 5,951,482 (approximately 595,148 common units after adjusting for reverse unit split), or 18.9% of our common units, and a subsidiary of SN owned 1,052,632 (approximately 105,263 common units after adjusting for reverse unit split), or 3.3% of our common units.

Sanchez-Related Agreements

On May 8, 2014, the Company and the Manager, an affiliate of SOG, entered into 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 six months ended June 30, 2015, we paid $2.4 million to the Manager under the Services Agreement, which included a prepayment of $0.5 million to be applied in the third quarter of 2015.

Additionally, as of June 30, 2015 and December 31, 2014, the Partnership had a net receivable from related parties of $2.5 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 June 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.

In August 2013, the Company entered into a Registration Rights Agreement with SEP I and 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 6, 2015, amendments to the Services Agreement and License Agreement were executed in order to replace the Company with the Partnership as counterparty to the agreements. No other material amendments have been made to the agreements mentioned herein. The amendments are attached as exhibits to this Quarterly Report on Form 10-Q.

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	132,766	17.08
Vested	(83,381)	18.79
Returned/Cancelled	(33,826)	17.30
Outstanding at June 30, 2015	25,641	$ 16.50

During the three months ended June 30, 2015, the Partnership issued 38,860 restricted common units (3,886 common units after adjusting for reverse unit split) pursuant to the LTIP to one director of the Partnership’s general partner that vested immediately on the date of the grant. The unit based compensation expense for the award was based on its grant date fair value of $1.93 per unit ($19.30 per unit after adjusting for reverse unit split) (the closing price of the Partnership’s common units on the grant date).

The remaining unvested units as of June 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 six months ended June 30, 2015.

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 June 30, 2015, we had 10,859,375 Class A preferred units outstanding and 31,450,596 common units outstanding (approximately 3,145,060 common units after adjusting for reverse unit split), which included 256,410 unvested restricted common units (25,641 common units after adjusting for reverse unit split) 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

The Partnership issued a total of 28,700 common units (2,870 common units after adjusting for reverse unit split) under its at-the-market facility during the three months ended June 30, 2015, for total net proceeds of less than $0.1 million.

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 plans to use 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 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 and distributed to the holders 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.

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

	March 6 - June 30 2015	January 1 - March 6 2015	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014
Class A units - Basic and diluted	-	484,505	-	484,505
Class B Common units - Basic and diluted	-	28,791,626	-	28,305,380
Common units - Basic and diluted	30,874,312	-	31,134,285	-
Weighted Average basic and diluted units prior to reverse split	30,874,312	29,276,131	31,134,285	28,789,885
Adjustment for reverse split	(27,786,881)	(26,348,518)	(28,020,857)	(25,910,896)
Weighted Average basic and diluted units after reverse split	3,087,431	2,927,613	3,113,428	2,878,989

At June 30, 2015, we had 256,410 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 June 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 - June 30	$ (99,928)	$ (99,928)
Basic and diluted loss per unit prior to reverse split		$ (3.23)
Basic and diluted loss per unit after reverse split		$ (32.37)

Net loss per unit increased significantly for the period from March 6, 2015 through June 30, 2015 as compared to the period from January 1, 2015 through March 5, 2015 as it included non-cash impairment charges of $83.7 million. There was no impairment charge recorded for the period from January 1, 2015 through March 5, 2015.

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

	Total	Class A Units	Class B Units
Assumed net loss to be allocated	$ (5,011)	$ (100)	$ (4,911)
Basic and diluted loss per unit prior to reverse split		$ (0.21)	$ (0.17)
Basic and diluted loss per unit after reverse split		$ (2.07)	$ (1.73)

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

	Total	Class A Units	Class B Units
Assumed net loss to be allocated	$ (7,950)	$ (159)	$ (7,791)
Basic and diluted loss per unit prior to reverse split		$ (0.15)	$ (0.28)
Basic and diluted loss per unit after reverse split		$ (1.52)	$ (2.76)

14. SUBSEQUENT EVENTS

On August 3, 2015, the Partnership completed 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.

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 an oil and gas exploration and production limited partnership focused on the acquisition, development and production of oil and natural gas properties and other integrated assets. SPP completed its initial public offering on November 20, 2006, as Constellation Energy Partners LLC (“CEP” or the “Company”), a master limited partnership. In August 2013, Sanchez Energy Partners I, LP (“SEP I”), an affiliate of Sanchez Oil & Gas Corporation (“SOG”), contributed certain oil and natural gas properties in Texas and Louisiana to CEP in exchange for equity interests in CEP. On May 8, 2014, the Company and SP Holdings, LLC (the “Manager”) entered into a Shared Services Agreement (the “Services Agreement”) pursuant to which the Manager agreed to provide services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. The Services Agreement became effective as of July 1, 2014. CEP’s name was subsequently changed to Sanchez Production Partners LLC, and on March 6, 2015, the Company’s unitholders approved the conversion of Sanchez Production Partners LLC to a Delaware limited partnership. As of the March 6, 2015 conversion date, 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.”

Our proved reserves are currently 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, although we have engaged a financial advisor related to the possible sale of our Oklahoma and Kansas assets. Our primary business objective is to create long-term value and to generate stable cash flows that allow us to resume and grow our distribution over time. We plan to achieve our objective by executing our business strategy, which is to:

- Pursue the possible sale of our Oklahoma and Kansas assets in 2015;

- Align our asset base, interests and operations with our sponsor, SOG;
- 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. References in this Quarterly Report on Form 10-Q to “SOG” and “SEP I” are to Sanchez Oil & Gas Corporation and Sanchez Energy Partners I, LP, respectively.

How We Evaluate our Operations

Non-GAAP Financial Measure—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)

•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.

Our Adjusted EBITDA should not be considered as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

The following table presents a reconciliation of net 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 June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Net loss	$ (10,341)	$ (5,011)	$ (100,327)	$ (7,950)
Adjusted by:				
Interest expense, net	1,122	533	1,768	1,058
Depreciation, depletion and amortization	3,079	4,320	6,199	8,370
Asset impairments	862	45	83,727	194
Accretion expense	264	150	517	300
Gain on sale of assets	(54)	(16)	(113)	(23)
Unit-based compensation programs	396	1,029	2,388	1,130
Loss on mark-to-market activities	9,902	5,915	10,634	10,912
Adjusted EBITDA	$ 5,230	$ 6,965	$ 4,793	$ 13,991

Significant Operational Factors

• Production. Our production for the six months ended June 30, 2015, was 725 MBOE, or an average of 4,007BOE per day, compared with approximately 755 MBOE, or an average of 4,173 BOE per day, for the six months ended June 30, 2014. We expect this production to increase during the remainder of 2015 with the addition of production from the Eagle Ford properties on March 31, 2015.

- Capital Expenditures. For the six months ended June 30, 2015, we spent 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”), $0.5 million in development expenditures focused on properties in Texas and Louisiana and $0.3 million in development expenditures focused on oil completions in the Cherokee Basin. 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 six months ended June 30, 2015, the non-cash mark-to-market loss for our commodity derivatives was approximately $10.6 million, compared to a loss of $10.9 million for the same period in 2014.

Results of Operations

Three months ended June 30, 2015 compared to three months ended June 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			
	June 30,		Variance	
	2015	2014	$	%
Revenues:				
Natural gas sales at market price	$ 3,618	$ 6,346	$ (2,728)	(43.0%)
Natural gas hedge settlements	1,877	1,596	281	17.6%
Natural gas mark-to-market activities	(2,219)	(2,232)	13	(0.6%)
Natural gas total	3,276	5,710	(2,434)	(42.6%)
Oil sales	6,194	9,028	(2,834)	(31.4%)
Oil hedge settlements	2,128	(412)	2,540	*
Oil mark-to-market activities	(7,683)	(3,683)	(4,000)	108.6%
Oil total	639	4,933	(4,294)	(87.0%)
Natural gas liquids sales	500	581	(81)	(13.9%)
Miscellaneous income	366	865	(499)	(57.7%)
Total revenues	4,781	12,089	(7,308)	(60.5%)
Operating expenses:				
Lease operating expenses	5,358	5,182	176	3.4%
Cost of sales	125	434	(309)	(71.2%)
Production taxes	583	995	(412)	(41.4%)
General and administrative	3,746	5,591	(1,845)	(33.0%)
Gain on sale of assets	(54)	(16)	(38)	237.5%
Depreciation, depletion and amortization	3,079	4,320	(1,241)	(28.7%)
Asset impairments	862	45	817	*
Accretion expenses	264	150	114	76.0%
Total operating expenses	13,963	16,701	(2,738)	(16.4%)
Other expenses (income):				
Interest expense	1,122	533	589	110.5%
Other (income) expense	37	(134)	171	(127.6%)
Total other expenses	1,159	399	760	190.5%
Total expenses	15,122	17,100	(1,978)	(11.6%)
Net loss	$ (10,341)	$ (5,011)	$ (5,330)	106.4%

* Not Meaningful

	For the Three Months Ended June 30, 2015	2014	Variance	
Net production:				
Natural gas production (MMcf)	1,553	1,675	(122)	(7.3%)
Oil production (MBbl)	112	89	22	25.1%
Natural gas liquids production (MBbl)	31	15	16	107.5%
Total production (BOE)	402	383	18	4.7%
Average daily production (BOE/d)	4,414	4,212	202	4.8%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.54	$ 4.74	$ (1.20)	(25.4%)
Natural gas price per Mcf without hedge settlements	$ 2.33	$ 3.79	$ (1.46)	(38.5%)
Oil price per Bbl with hedge settlements	$ 74.43	$ 96.42	$ (21.98)	(22.8%)
Oil price per Bbl without hedge settlements	$ 55.40	$ 101.03	$ (45.63)	(45.2%)
Liquid price per Bbl without hedge settlements	$ 16.18	$ 38.99	$ (22.82)	(58.5%)
Total price per BOE with hedge settlements	$ 35.65	$ 44.69	$ (9.04)	(20.2%)
Total price per BOE without hedge settlements	$ 25.68	$ 41.60	$ (15.93)	(38.3%)
Average unit costs per BOE:				
Field operating expenses	$ 14.79	$ 16.11	$ (1.31)	(8.2%)
Lease operating expenses	$ 13.34	$ 13.51	$ (0.17)	(1.3%)
Production taxes	$ 1.45	$ 2.59	$ (1.14)	(44.1%)
General and administrative expenses	$ 9.33	$ 14.58	$ (5.25)	(36.0%)
General and administrative expenses without unit-based compensation	$ 8.34	$ 11.90	$ (3.56)	(29.9%)
Depreciation, depletion and amortization	$ 7.67	$ 11.26	$ (3.59)	(31.9%)

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

Production. For the three months ended June 30, 2015, 28% of our production was oil, 8% was NGLs and 64% was natural gas as compared to the three months ended June 30, 2014, where 23% of our production was oil, 4% was NGLs and 73% was natural gas. The production mix between the periods has remained fairly consistent. The amount of oil as a percentage of total production has increased during the three months ended June 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 $2.8 million, or 31%, to $6.2 million for the three months ended June 30, 2015, compared to $9.0 million for the same period in 2014. NGL sales decreased $0.1 million, or 14%, to $0.5 million for the three months ended June 30, 2015, compared to $0.6 million for the same period in 2014. Unhedged natural gas sales decreased $2.7 million, or 43%, to $3.6 million for the three months ended June 30, 2015, compared to $6.3 million for the same period in 2014.

Including hedges and mark-to-market activities, our total revenue decreased $7.3 million, compared to the same period in 2014. This decrease was the result of a $4.0 million increase in losses on mark-to-market activities and $8.0 million attributable to lower market prices for our natural gas, offset by a $2.4 million increase related to higher sales volumes and a $2.8 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.

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 June 30, 2014 to the three months ended June 30, 2015 (dollars in thousands):

	Q2 2015 Production Volume	Q2 2014 Production Volume	Production Volume Difference	Q2 2014 Average Sales Price	Revenue Increase/(Decrease) due to Production
Oil (MBbl)	112	89	22	$ 101.03	$ 2,267
Natural gas liquids (MBbl)	31	15	16	$ 38.99	$ 624
Natural gas (MMcf)	1,553	1,675	(122)	$ 3.79	$ (462)
Total oil equivalent (BOE)	402	383	18	$ 41.60	$ 754

	Q2 2015 Average Sales Price	Q2 2014 Average Sales Price	Average Sales Price Difference	Q2 2015 Volume	Revenue Decrease due to Price
Oil (MBbl)	$ 55.40	$ 101.03	$ (45.63)	112	$ (5,101)
Natural gas liquids (MBbl)	$ 16.18	$ 38.99	$ (22.82)	31	$ (705)
Natural gas (MMcf)	$ 2.33	$ 3.79	$ (1.46)	1,553	$ (2,266)
Total oil equivalent (BOE)	$ 25.68	$ 41.60	$ (15.93)	402	$ (6,397)

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 June 30, 2015 by $1.0 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 June 30, 2015, the non-cash mark-to-market loss was $9.9 million, compared to a loss of $5.9 million for the same period in 2014. The 2015 and 2014 non-cash losses 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 $4.0 million for the three months ended June 30, 2015, compared to $1.2 million for the three months ended June 30, 2014. This difference was primarily due to changes in market prices for oil and natural gas during 2015 and 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.

For the three months ended June 30, 2015, lease operating expenses increased $0.2 million, or 3.4%, to $5.4 million, compared to expenses of $5.2 million for the same period in 2014. This increase in lease operating expenses was related to an increase of $0.2 million in ad valorem taxes relating to the Palmetto properties.

For the three months ended June 30, 2015, per unit lease operating expenses were $13.34 per BOE compared to $13.51 per BOE for the same period in 2014. This decrease is due to increased 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 decreased $1.8 million, or 33%, to 3.8 million for the three months ended June 30, 2015, compared to $5.6 million for the same period in 2014. Our general and administrative expenses were lower in 2015 due to a $1.0 million decrease in labor and incentive compensation costs relating to severance costs and a $1.0 million decrease in unit-based compensation. These decreases were offset by a $0.2 million increase in legal and professional services.

Our general and administrative expenses were $9.33 per BOE for the three months ended June 30, 2015, compared to $14.58 per BOE for the same period in 2014. Excluding unit-based compensation, our general and administrative costs were $8.34 per BOE for the three months ended June 30, 2015, compared to $11.90 per BOE for the same period in 2014. These decreases resulted from the decreased costs noted above as well as the increased production between the periods.

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 June 30, 2015 was $3.1 million, or $7.67 per BOE, compared to $4.3 million, or $11.26 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 increased 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 June 30, 2015, we recorded non-cash charges of $0.9 million to impair the value of our oil and natural gas fields in Texas and Louisiana. 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 June 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 June 30, 2015 increased $0.6 million, or 110%, to $1.1 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.

Six months ended June 30, 2015 compared to six months ended June 30, 2014

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

	For the Six Months Ended		Variance	
	2015	2014	$	%
Revenues:				
Natural gas sales at market price	$ 6,837	$ 14,769	$ (7,932)	(53.7%)
Natural gas hedge settlements	3,418	2,603	815	31.3%
Natural gas mark-to-market activities	(1,570)	(6,406)	4,836	(75.5%)
Natural gas total	8,685	10,966	(2,281)	(20.8%)
Oil sales	8,515	15,383	(6,868)	(44.6%)
Oil hedge settlements	6,152	(496)	6,648	*
Oil mark-to-market activities	(9,064)	(4,506)	(4,558)	101.2%
Oil total	5,603	10,381	(4,778)	(46.0%)
Natural gas liquids sales	886	850	36	4.2%
Miscellaneous income	1,531	1,633	(102)	(6.2%)
Total revenues	16,705	23,830	(7,125)	(29.9%)
Operating expenses:				

Lease operating expenses	10,258	10,302	(44)	(0.4%)
Cost of sales	330	794	(464)	(58.4%)
Production taxes	953	1,767	(814)	(46.1%)
General and administrative	13,293	9,162	4,131	45.1%
Gain on sale of assets	(113)	(23)	(90)	*
Depreciation, depletion and amortization	6,199	8,370	(2,171)	(25.9%)
Asset impairments	83,727	194	83,533	*
Accretion expenses	517	300	217	72.3%
Total operating expenses	115,164	30,866	84,298	*
Other expenses (income):				
Interest expense	1,768	1,058	710	67.1%
Other (income) expense	100	(144)	244	*
Total other expenses	1,868	914	954	104.4%
Total expenses	117,032	31,780	85,252	*
Net loss	$ (100,327)	$ (7,950)	$ (92,377)	*

* Not Meaningful

	For the Six Months Ended June 30, 2015	2014	Variance	
Net production:				
Natural gas production (MMcf)	3,124	3,416	(292)	(8.5%)
Oil production (MBbl)	156	154	2	1.3%
Natural gas liquids production (MBbl)	48	32	17	52.2%
Total production (BOE)	725	755	(30)	(4.0%)
Average daily production (BOE/d)	4,007	4,171	(164)	(3.9%)
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.28	$ 5.09	$ (1.80)	(35.5%)
Natural gas price per Mcf without hedge settlements	$ 2.19	$ 4.32	$ (2.14)	(49.4%)
Oil price per Bbl with hedge settlements	$ 93.94	$ 96.60	$ (2.65)	(2.7%)
Oil price per Bbl without hedge settlements	$ 54.54	$ 99.81	$ (45.28)	(45.4%)
Liquid price per Bbl without hedge settlements	$ 18.31	$ 26.74	$ (8.43)	(31.5%)
Total price per BOE with hedge settlements	$ 35.59	$ 43.84	$ (8.25)	(18.8%)
Total price per BOE without hedge settlements	$ 22.39	$ 41.05	$ (18.66)	(45.5%)
Average unit costs per BOE:				
Field operating expenses	$ 15.46	$ 15.98	$ (0.52)	(3.3%)
Lease operating expenses	$ 14.14	$ 13.64	$ 0.50	3.7%
Production taxes	$ 1.31	$ 2.34	$ (1.03)	(43.8%)
General and administrative expenses	$ 18.33	$ 12.13	$ 6.20	51.1%
General and administrative expenses without unit-based compensation	$ 15.04	$ 10.63	$ 4.40	41.4%
Depreciation, depletion and amortization	$ 8.55	$ 11.08	$ (2.53)	(22.8%)

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

Production: For the six months ended June 30, 2015, 22% of our production was oil, 7% was NGLs and 71% was natural gas as compared to the six months ended June 30, 2014, where 21% of our production was oil, 4% was NGLs and 75% was natural gas. The production mix between the periods has remained fairly consistent. We expect the amount of oil as a percentage of total production to increase during the remainder of 2015 as production from the newly acquired Eagle Ford properties, which are significantly more weighted towards oil than our previous asset base, are included in our reported production.

Oil, NGL and natural gas sales. Unhedged oil sales decreased $6.9 million, or 45%, to $8.5 million for the six months ended June 30, 2015, compared to $15.4 million for the same period in 2014. NGL sales remained flat at $0.9 million for the six months ended June 30, 2015, compared to $0.9 million for the same period in 2014. Unhedged natural gas sales decreased approximately $7.9 million, or 54%, to $6.8 million for the six months ended June 30, 2015, compared to $14.8 million for the same period in 2014.

Including hedges and mark-to-market activities, our total revenue decreased $7.1 million, compared to the same period in 2014. This decrease was the result of a $14.1 million decrease attributable to lower market prices for our natural gas and a $0.6 million decrease related to higher sales volumes, offset by a $0.3 million increase in gains on mark-to-market activities and a $7.4 million increase in settlements on our commodity derivatives. The remainder of the decrease is related to a decrease between the periods of $0.1 million in miscellaneous income.

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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 six months ended June 30, 2014 to the six months ended June 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
Oil (MBbl)	156	154	2	$ 99.81	$ 201
Natural gas liquids (MBbl)	48	32	17	$ 26.74	$ 444
Natural gas (MMcf)	3,124	3,416	(292)	$ 4.32	$ (1,261)
Total oil equivalent (BOE)	725	755	(30)	$ 41.05	$ (1,232)

	YTD 2015 Average Sales Price	YTD 2014 Average Sales Price	Average Sales Price Difference	YTD 2015 Volume	Revenue Decrease due to Price
Oil (MBbl)	$ 54.54	$ 99.81	$ (45.28)	156	$ (7,069)
Natural gas liquids (MBbl)	$ 18.31	$ 26.74	$ (8.43)	48	$ (408)
Natural gas (MMcf)	$ 2.19	$ 4.32	$ (2.14)	3,124	$ (6,671)
Total oil equivalent (BOE)	$ 22.39	$ 41.05	$ (18.66)	725	$ (13,532)

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 six months ended June 30, 2015 by $1.6 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 six months ended June 30, 2015, the non-cash mark-to-market loss was $10.6 million, compared to a loss of $10.9 million for the same period in 2014. The 2015 and 2014 non-cash losses 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 $9.6 million for the six months ended June 30, 2015, compared to $2.1 million for the six months ended June 30, 2014. This difference was primarily due to changes in market prices for oil and natural gas during 2015 and 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.

For the six months ended June 30, 2015, lease operating expenses remained flat when compared to the same period in 2014. On a per unit basis, lease operating expenses were $14.14 per BOE compared to $13.64 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 $4.1 million, or 45%, to $13.3 million for the six months ended June 30, 2015, compared to $9.2 million for the same period in 2014. Our general and administrative expenses were higher in 2015 due to $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 $0.9 million increase in unit-based compensation and a $0.7 million increase in legal and professional services.

Our general and administrative expenses were $18.33 per BOE for the six months ended June 30, 2015, compared to $12.13 per BOE for the same period in 2014. Excluding unit-based compensation, our general and administrative costs were $15.04 per BOE for the six months ended June 30, 2015, compared to $10.63 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 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 six months ended June 30, 2015 was $6.2 million, or $8.55 per BOE, compared to $8.4 million, or $11.08 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 six months ended June 30, 2015, we recorded non-cash charges of $83.7 million 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. 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 six months ended June 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 six months ended June 30, 2015 increased $0.7 million, or 67.1%, to $1.8 million, compared to $1.1 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 2.9% and 3.2% as of June 30, 2015 and 2014, respectively.

Liquidity and Capital Resources

As of June 30, 2015, we had approximately $5.2 million in cash and cash equivalents, $0.6 million in restricted cash, and $4.0 million available under the $110 million current borrowing base of our Credit Agreement.

Our capital expenditures during the six months ended June 30, 2015 were funded with cash on hand, borrowings under our Credit Agreement, a private placement of preferred units and the issuance of common units as part of our consideration given in the Eagle Ford acquisition. Our current expectation is that we will continue managing our business to operate within the cash flows that are generated. Our quarterly distributions to our unitholders currently remain suspended and we are restricted from paying distributions to unitholders as we have no available cash (taking into account the cash reserves set by the board of directors of our general partner for the proper conduct of our business) from which to pay distributions.

Our future success in growing our asset base will be highly dependent on the capital resources available to us and our success in acquiring additional reserves or other assets and managing the costs associated with our operations. We routinely monitor and adjust our capital expenditures and operating expenses in response to changes in oil and natural gas prices, production and acquisition costs, industry conditions, availability of funds under our Credit Agreement and internally generated cash flow. Based upon current oil and natural gas price expectations, our existing hedge position and expected production levels in 2015, we anticipate that our cash flow from operations can meet our planned capital expenditures and other cash requirements for the next twelve months without increasing our debt. If needed, or in connection with the acquisition of additional assets, we may issue additional debt or equity securities to raise additional capital. Future cash flow and our borrowing capacity are subject to a number of variables, including oil and natural gas production, the market prices for those products and our hedge position. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our 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.

Sources of Debt and Equity Financing

As of June 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. 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 June 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 the second quarter of 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 June 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 six months ended June 30, 2015 of $4.9 million, compared to net cash flow provided by operating activities of $6.0 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 six months ended June 30, 2015 of $82.1 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 $0.7 million in development expenditures focused on properties in Texas and Louisiana, offset by $0.3 million in proceeds from the sale of assets during the period.

During the six months ended June 30, 2014, our cash capital expenditures were $5.2 million, consisting of $1.4 million for the purchase of oil and natural gas properties in LaSalle Parish, Louisiana, $2.3 million in development expenditures focused on oil completions in the Cherokee Basin and $1.5 million in development expenditures focused on properties in Texas and Louisiana. We completed four net wells and four net recompletions during the six months ended June 30, 2014 and had one net well and net recompletion in progress at June 30, 2014.

Net Cash Provided by (Used in) Financing Activities

Net cash flows provided by financing activities was $78.2 million for the six months ended June 30, 2015, compared to $1.5 million used in financing activities for the same period in 2014. During the six months ended June 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 $1.5 million for the six months ended June 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 $0.2 million during the six months ended June 30, 2014 to fund the cost of units tendered by employees for tax withholdings for unit-based compensation.

Off-Balance Sheet Arrangements

As of June 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 June 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 June 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.

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 June 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 June 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.

Part II—Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in our Current Report on Form 8-K that was filed with the SEC on 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.

Common unitholders may be required to pay taxes on income from us, including their share of ordinary income and any capital gains on dispositions of properties by us, 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. Generally, should we generate taxable income for a particular tax year and not pay any cash distributions, our common unitholders will be required to pay the actual U.S. federal income tax liability that results from their share of such taxable income even though they received no cash distributions from us. We did not make any distributions to our common unitholders in 2014. If we do not make any distributions in 2015, our common unitholders will likely be required to pay U.S. federal income tax on their share of our taxable income for 2015, if any, without the benefit of any cash distributions from 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, 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.

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.

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

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.

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 resume, maintain and grow distributions;

•drilling locations;

•oil, natural gas and natural gas liquids reserves;

•realized oil, natural gas and natural gas liquids prices;

•production volumes;

•lease operating expenses, general and administrative expenses and developmental costs;

•future operating results; 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

None.

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 six months ended June 30, 2015 and June 30, 2014

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

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

Notes to Condensed Consolidated Financial Statements

EXHIBIT INDEX

Exhibit Number	Description
*10.1 —	Amendment and Waiver of Third Amended and Restated Credit Agreement, dated as of August 12, 2015, between Sanchez Production Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent.
*3.1 —	Amendment No. 1 to Limited Liability Company Agreement of Sanchez Production Partners GP LLC.
*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

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: August 14, 2015	By	/s/ Charles C. Ward Charles C. Ward Chief Financial Officer and Secretary