Mid-Con Energy Partners, LP
Form 10-Q
August 02, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File No.: 1-35374

Mid-Con Energy Partners, LP

(Exact name of registrant as specified in its charter)

Delaware	45-2842469
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

2431 East 61st Street, Suite 850

Tulsa, Oklahoma 74136

(Address of principal executive offices and zip code)

(918) 743-7575

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the 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 and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

As of August 2, 2017, the registrant had 30,091,463 common units.

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FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q ("Form 10-Q") contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (each a "forward-looking statement"). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- volatility or continued low or further declining commodity prices;
- revisions to oil and natural gas reserves estimates as a result of changes in commodity prices;
- effectiveness of risk management activities;
- business strategies;
- future financial and operating results;
- our ability to pay distributions;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- future capital requirements and availability of financing;
- technology;
- realized oil and natural gas prices;
- production volumes;
- lease operating expenses;
- general and administrative expenses;
- cash flow and liquidity;
- availability of production equipment;
- availability of oil field labor;
- capital expenditures;
- availability and terms of capital;
- marketing of oil and natural gas;
- general economic conditions;
- competition in the oil and natural gas industry;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation;
- developments in oil producing and natural gas producing countries; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 1. "Financial Statements," Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this 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," "predict," "potential," "pursue," "target," "c "forecast," "guidance," "might," "scheduled" and the negative of such terms or other comparable terminology.

The forward-looking statements contained in this 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. All readers are cautioned that the forward-looking statements contained in this Form 10-Q are not guarantees of future performance and we cannot assure any reader that such statements will be realized or that the forward-looking events will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in the "Risk Factors" section included in Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2016 ("Annual Report") and Part II, Item 1A. in this Form 10-Q. All forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to 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.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge on our website (www.midconenergypartners.com), copies of our Annual Reports, Form 10-Qs, Current Reports on Form 8-K, amendments to those reports filed or furnished to the Securities and Exchange Commission ("SEC") pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct and the written charter of our Audit Committee are also available on our website and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

PART I

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Balance Sheets

(in thousands, except number of units)

(Unaudited)

	Period Ended June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$486	$ 2,359
Accounts receivable:		
Oil and natural gas sales	4,254	5,302
Other	83	233
Derivative financial instruments	348	—
Prepaids and other	288	512
Total current assets	5,459	8,406
Property and Equipment:		
Oil and natural gas properties, successful efforts method:		
Proved properties	450,576	441,479
Other property and equipment	852	289
Accumulated depletion, depreciation, amortization and impairment	(203,723)	(176,551)
Total property and equipment, net	247,705	265,217
Derivative financial instruments	458	—
Other assets	1,983	2,663
Total Assets	$255,605	$ 276,286
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities		
Accounts payable:		
Trade	$257	$ 256
Related parties	1,364	3,431
Derivative financial instruments	580	5,314
Accrued liabilities	498	146
Total current liabilities	2,699	9,147
Derivative financial instruments	-	2,495
Long-term debt	121,000	122,000
Other long term liabilities	81	93
Asset retirement obligations	12,119	11,331
Commitments and contingencies		

Class A convertible preferred units - 11,627,906 issued and outstanding, respectively	19,970	19,570
EQUITY, per accompanying statements:		
Partnership equity		
General partner interest	(376)	(248)
Limited partners- 29,944,796 and 29,912,230 units issued and outstanding, respectively	100,112	111,898
Total equity	99,736	111,650
Total liabilities, convertible preferred units and equity	$255,605	$ 276,286

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Operations

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Revenues				
Oil sales	$13,657	$14,447	$28,612	$25,553
Natural gas sales	288	330	684	493
Gain (loss) on derivatives, net	2,533	(10,088)	5,665	(7,520)
Total revenues	16,478	4,689	34,961	18,526
Operating costs and expenses				
Lease operating expenses	5,581	5,777	10,573	11,842
Oil and natural gas production taxes	707	732	1,509	1,324
Impairment of proved oil and natural gas properties	17,672	895	17,672	895
Impairment of proved oil and natural gas properties sold	—	3,578	—	3,578
Depreciation, depletion and amortization	4,631	5,800	9,500	11,885
Accretion of discount on asset retirement obligations	136	159	244	316
General and administrative	1,471	1,478	3,297	3,566
Total operating costs and expenses	30,198	18,419	42,795	33,406
Gain on sale of oil and natural gas properties, net	—	13	—	13
Loss from operations	(13,720)	(13,717)	(7,834)	(14,867)
Other (expense) income				
Interest income	2	2	5	5
Interest expense	(1,539)	(2,054)	(2,989)	(4,253)
Other income	66	—	66	33
Loss on settlements of asset retirement obligations	(8)	—	(5)	—
Total other expense	(1,479)	(2,052)	(2,923)	(4,215)
Net loss	(15,199)	(15,769)	(10,757)	(19,082)
Less: Distributions to preferred unitholders	694	—	1,492	—
Less: General partner's interest in net loss	(181)	(188)	(128)	(227)
Limited partners' interest in net loss	$(15,712)	$(15,581)	$(12,121)	$(18,855)
Limited partners' interest in net loss per unit:				
Basic and diluted	$(0.52)	$(0.52)	$(0.40)	$(0.63)
Weighted average limited partner units outstanding:				
Limited partner units (basic and diluted)	29,945	29,785	29,936	29,777

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Cash Flows

(in thousands)

(Unaudited)

	Six Months Ended June 30, 2017	2016
Cash Flows from Operating Activities:		
Net loss	$(10,757)	$(19,082)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	9,500	11,885
Debt issuance costs amortization	680	674
Accretion of discount on asset retirement obligations	244	316
Impairment of proved oil and natural gas properties	17,672	895
Impairment of proved oil and natural gas properties sold	—	3,578
Loss on settlements of asset retirement obligations	5	—
Cash paid for settlements of asset retirement obligations	(21)	—
Mark to market on derivatives:		
(Gain) loss on derivatives, net	(5,665)	7,520
Cash settlements received for matured derivatives	201	17,285
Cash premiums paid for derivatives, net	(2,571)	(2,257)
Gain on sale of oil and natural gas properties	—	(13)
Non-cash equity-based compensation	335	650
Changes in operating assets and liabilities:		
Accounts receivable	1,048	(682)
Other receivables	150	3,822
Prepaids and other	224	146
Accounts payable - trade and accrued liabilities	308	1,032
Accounts payable - related parties	(2,027)	(870)
Net cash provided by operating activities	9,326	24,899
Cash Flows from Investing Activities:		
Acquisitions of oil and natural gas properties	(4,666)	—
Additions to oil and natural gas properties	(4,341)	(3,495)
Additions to other property and equipment	(133)	—
Proceeds from sale of oil and natural gas properties	—	7
Net cash used in investing activities	(9,140)	(3,488)
Cash Flows from Financing Activities:		
Proceeds from line of credit	4,000	—
Payments on line of credit	(5,000)	(17,982)
Offering costs	(59)	(16)
Debt issuance costs	—	(9)
Distributions to Class A convertible preferred units	(1,000)	—
Net cash used in financing activities	(2,059)	(18,007)
Net (decrease) increase in cash and cash equivalents	(1,873)	3,404
Beginning cash and cash equivalents	2,359	615

Ending cash and cash equivalents	$486	$4,019

See accompanying notes to condensed consolidated financial statements

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Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Changes in Equity

(in thousands)

(Unaudited)

	General Partner	Limited Partner Units	Limited Partner Amount	Total Equity
Balance, December 31, 2016	$ (248)	29,912	$111,898	$111,650
Equity-based compensation	—	33	335	335
Distributions to Class A convertible preferred units	—	—	(1,000)	(1,000)
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(492)	(492)
Net loss	(128)	—	(10,629)	(10,757)
Balance, June 30, 2017	$ (376)	29,945	$100,112	$99,736

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Operations

Nature of Operations

Mid-Con Energy Partners, LP (“we,” “our,” “us,” the “Partnership,” or the “Company”) is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on enhanced oil recovery (“EOR”). Our common units representing limited partner interests in us (“common units”) are listed on the National Association of Securities Dealers Automated Quotation System Global Select Market (“NASDAQ”) under the symbol “MCEP.” Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company.

Basis of Presentation

Our unaudited condensed consolidated financial statements are prepared pursuant to the rules and regulations of the SEC. These financial statements have not been audited by our independent registered public accounting firm, except that the condensed consolidated balance sheet at December 31, 2016, is derived from the audited financial statements. Accordingly, certain information and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) have been condensed or omitted in this Form 10-Q. We believe that the presentations and disclosures made are adequate to make the information not misleading.

The unaudited condensed consolidated financial statements include all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the interim periods. The results of operations for the interim periods are not necessarily indicative of the results of operations to be expected for the full year. These interim financial statements should be read in conjunction with our Annual Report. All intercompany transactions and account balances have been eliminated.

Reclassifications

Certain amounts in the financial statements for the prior years have been reclassified to conform to the 2017 presentation. These reclassifications have no impact on previously reported total assets, total liabilities, net income (loss) or total operating cash flows.

Non-cash Investing, Financing and Supplemental Cash Flow Information

The following presents the non-cash investing, financing and supplemental cash flow information for the periods presented:

	Six Months Ended June 30,	
	2017	2016
	(in thousands)	
Non-cash investing and financing information:		
Change in oil and natural gas properties - accrued	$(40)	$(379)

capital expenditures		
Supplemental cash flow information:		
Cash paid for interest	$2,305	$3,700

Note 2. Acquisitions and Divestitures

Acquisitions

Acquisitions are accounted for under the acquisition method of accounting. The assets acquired and liabilities assumed in acquisitions are recorded in our unaudited condensed consolidated balance sheets at their estimated fair values as of the acquisition date using assumptions that represent Level 3 fair value measurement inputs. See Note 5 in this section for additional discussion of our fair value measurements. Results of operations attributable to the acquisition subsequent to the closing are included in our unaudited condensed consolidated statements of operations.

Permian Bolt-On

In August 2016, we acquired multiple oil and natural gas properties located in Nolan County, Texas (the “Permian Bolt-On”) for cash consideration of approximately $18.7 million, after post-closing purchase price adjustments. The transaction was funded by a private offering of $25.0 million Class A Convertible Preferred Units (“Preferred Units”). See Note 9 in this section for additional information regarding the issuance of Preferred Units. The recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

Fair value of net assets acquired:	
Oil and natural gas properties	$19,323
Total assets acquired	19,323
Fair value of net liabilities assumed:	
Asset retirement obligation	622
Net assets acquired	$18,701

Wheatland

In June 2017, we acquired multiple oil and natural gas properties located in Oklahoma County and Cleveland County, Oklahoma (“Wheatland”) for cash consideration of approximately $4.2 million, prior to post-closing purchase price adjustments. The recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

Fair value of net assets acquired:	
Oil and natural gas properties	$4,465
Other property and equipment	127
Total assets acquired	4,592
Fair value of net liabilities assumed:	
Asset retirement obligation	407
Net assets acquired	$4,185

Divestitures

Hugoton

In July 2016, we sold the properties located in our Hugoton core area for cash proceeds of approximately $17.6 million, including post-closing purchase price adjustments and recognized a loss of approximately $0.6 million. Additionally, we recorded impairment of proved oil and natural gas properties of approximately $3.6 million when these properties were originally reported as held for sale. For the three months ended June 30, 2016, our unaudited condensed consolidated statements of operations included revenues of approximately $1.8 million and expenses of approximately $5.3 million related to the oil and natural gas properties sold. For the six months ended June 30, 2016, our unaudited condensed consolidated statements of operations included revenues of approximately $3.0 million and expenses of approximately $7.1 million related to the oil and natural gas properties sold. Effective at closing, the operations and cash flows of these properties were eliminated from the ongoing operations of the Partnership and the Partnership has no continuing involvement in these properties. This divestiture did not represent a strategic shift and did not have a major effect on the Partnership’s operations or financial results.

Note 3. Equity Awards

We have a long-term incentive program (the “Long-Term Incentive Program”) for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating, LLC (“Mid-Con Energy Operating”) and ME3 Oilfield Service, LLC (“ME3 Oilfield Service”), who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, unrestricted units, restricted units, phantom units, distribution equivalent rights granted with phantom units and other types of awards. The Long-Term Incentive Program is administered by Charles R. Olmstead, Executive Chairman of the Board, and Jeffrey R. Olmstead, President and Chief Executive Officer, and approved by the Board of Directors of our general partner (the “Board”). We account for unrestricted, restricted and equity-settled phantom unit awards as equity awards since they are settled by issuing common units. If an employee terminates employment prior to the restriction lapse date, the awarded units are forfeited and canceled and are no longer considered issued and outstanding.

On January 1, 2017, we adopted ASU 2016-09 Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (“ASU 2016-09”) and elected to recognize forfeitures of equity awards as they occur. The cumulative effect of adopting ASU 2016-09 was determined to be immaterial and no adjustment to retained earnings was made.

The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at June 30, 2017:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,212,706)
Restricted units granted, net of forfeitures	(400,424)
Equity-settled phantom units granted, net of forfeitures	(456,500)
Awards available for future grant	1,444,370

We recognized approximately $0.1 million and $0.3 million of total equity-based compensation expense for the three and six months ended June 30, 2017, respectively, and we recognized approximately $0.3 million and $0.7 million of total equity-based compensation expense for the three and six months ended June 30, 2016, respectively. These costs are reported as a component of general and administrative expenses ("G&A") in our unaudited condensed consolidated statements of operations.

Unrestricted Unit Awards

During the six months ended June 30, 2017, we granted 25,400 unrestricted units with an average grant date fair value of $2.65 per unit. During the six months ended June 30, 2016, we granted 70,000 unrestricted units with an average grant date fair value of $1.16 per unit.

Restricted Unit Awards

Restricted units vest over a two- or three-year period. As of June 30, 2017, there were approximately $0.04 million of unrecognized compensation costs related to non-vested restricted units. These costs are expected to be recognized over a weighted average period of approximately five months.

A summary of our restricted unit awards for the six months ended June 30, 2017, is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2016	76,922	$ 5.67
Units granted	—	—
Units vested	(66,030)	4.96
Units forfeited	—	—
Outstanding at June 30, 2017	10,892	$ 9.99

Equity-Settled Phantom Unit Awards

Equity-settled phantom units vest over a two- or three-year period and do not have any rights or privileges of a common unitholder, including right to distributions, until vesting and the resulting conversion into common units. During the six months ended June 30, 2017, we granted 9,000 equity-settled phantom units with a three-year vesting period. During the six months ended June 30, 2016, we granted 24,500 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years. As of June 30, 2017, there were approximately $0.2 million of unrecognized compensation costs related to non-vested equity-settled phantom units. These costs are expected to be recognized over a weighted average period of approximately one year, three months.

A summary of our equity-settled phantom unit awards for the six months ended June 30, 2017, is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2016	287,659	$ 1.64
Units granted	9,000	2.65
Units vested	(7,166)	1.16
Units forfeited	(10,000)	2.94
Outstanding at June 30, 2017	279,493	$ 1.64

Note 4. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. These contracts are presented as derivative financial instruments on our unaudited condensed consolidated financial statements. We account for our commodity derivative contracts at fair value. See Note 5 in this section for a description of our fair value measurements.

We do not designate derivatives as hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of our commodity derivative contracts is recorded in current period earnings. When prices for oil are volatile, a significant portion of the effect of our hedging activities consists of non-cash gains or losses due to changes in the fair value of our commodity derivative contracts. In addition to mark-to-market adjustments, gains or losses arise from net payments made or received on monthly settlements, proceeds from or payments for termination of contracts prior to their expiration and premiums paid or received for new contracts. Any deferred premiums are recorded as a liability and recognized in earnings as the related contracts mature. Gains and losses on derivatives are included in cash flows from operating activities. Pursuant to the accounting standard that permits netting of assets and liabilities where the right of offset exists, we present the fair value of commodity derivative contracts on a net basis.

At June 30, 2017, our commodity derivative contracts were in a net asset position with a fair value of approximately $0.2 million and at December 31, 2016, a net liability position with a fair value of approximately $7.8 million. All of our commodity derivative contracts are with major financial institutions that are also lenders under our revolving credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our commodity derivative contracts under lower commodity prices and we could incur a loss. As of June 30, 2017, all of our counterparties have performed pursuant to the terms of their commodity derivative contracts.

The following tables summarize the gross fair value by the appropriate balance sheet classification, even when the derivative financial instruments are subject to netting arrangements and qualify for net presentation, in our unaudited condensed consolidated balance sheets at June 30, 2017, and December 31, 2016:

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets
	(in thousands)		
June 30, 2017:			
Assets			
Derivative financial instruments - current asset	$2,516	$ (2,168)	$ 348
Derivative financial instruments - long-term asset	948	(490)	458
Total	3,464	(2,658)	806
Liabilities			
Derivative financial instruments - current liability	(271)	(309)	(580)
Derivative deferred premium - current liability	(2,477)	2,477	—
Derivative financial instruments - long-term liability	(89)	89	—
Derivative deferred premium - long-term liability	(401)	401	—
Total	(3,238)	2,658	(580)
Net Asset	$226	$ —	$ 226

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets
	(in thousands)		
December 31, 2016:			
Assets			
Derivative financial instruments - current asset	$1,570	$ (1,570)	$ —
Derivative financial instruments - long-term asset	406	(406)	—
Total	1,976	(1,976)	—
Liabilities			
Derivative financial instruments - current liability	(1,836)	(3,478)	(5,314)

Derivative deferred premium - current liability	(5,048)	5,048	—
Derivative financial instruments - long-term liability	(2,500)	5	(2,495)
Derivative deferred premium - long-term liability	(401)	401	—
Total	(9,785)	1,976	(7,809)
Net Liability	$(7,809)	$ —	$ (7,809)

The following table presents the impact of derivative financial instruments and their location within the unaudited condensed consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Net settlements on matured derivatives[1]	$357	$6,191	$201	$17,285
Net change in fair value of derivatives	2,176	(16,279)	5,464	(24,805)
Total gain (loss) on derivatives, net	$2,533	$(10,088)	$5,665	$(7,520)

[1]The settlement amount does not include premiums paid attributable to contracts that matured during the respective period.

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At June 30, 2017, and December 31, 2016, our commodity derivative contracts had maturities at various dates through December 2019 and were comprised of commodity price put and collar contracts. At June 30, 2017, we had the following oil derivatives net positions:

Period Covered	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Collars - 2017	45.00	51.78	652	WTI
Puts - 2017	50.00	—	1,875	WTI
Collars - 2018	44.38	55.52	1,315	WTI
Puts - 2018	45.00	—	164	WTI
Collars - 2019	50.00	60.52	427	WTI

At December 31, 2016, we had the following oil derivatives net positions:

Period Covered	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Collars - 2017	$ 43.75	$ 50.68	658	WTI
Puts - 2017	$ 50.00	$ —	1,932	WTI
Collars - 2018	$ 44.38	$ 55.52	1,315	WTI
Puts - 2018	$ 45.00	$ —	164	WTI
Collars - 2019	$ 50.00	$ 60.52	427	WTI

Note 5. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our unaudited condensed consolidated balance sheets for cash, accounts receivable and accounts payable approximate their fair values. The carrying amount of debt under our revolving credit facility approximates fair value because the revolving credit facility's variable interest rate resets frequently and approximates current market rates available to us. We account for our commodity derivative contracts at fair value as discussed in "Assets and Liabilities Measured at Fair Value on a Recurring Basis" below.

Fair Value Measurements

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. GAAP establishes a three-tier fair value hierarchy that is intended to increase consistency and comparability in fair value measurements and related disclosures. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities recorded in the balance sheet are categorized based on the inputs to the valuation technique as follows:

Level 1—Financial assets and liabilities for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. We consider active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an on-going basis.

Level 2—Financial assets and liabilities for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability. Level 2 instruments primarily include swap, call, put and collar contracts.

Level 3—Financial assets and liabilities for which values are based on prices or valuation approaches that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. We had no transfers in or out of Levels 1, 2 or 3 at June 30, 2017, and December 31, 2016.

Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no material changes in valuation approach or related inputs for the six months ended June 30, 2017, and for the year ended December 31, 2016.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We account for commodity derivative contracts and their corresponding deferred premiums at fair value on a recurring basis utilizing certain pricing models. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. The Partnership's deferred premiums associated with its commodity derivative contracts are categorized as Level 3, as the Partnership utilizes a net present value calculation to determine the valuation. See Note 4 in this section for a summary of our derivative financial instruments.

The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value on a recurring basis as of June 30, 2017, and December 31, 2016:

	Level 1	Level 2	Level 3	Fair Value
	(in thousands)			
June 30, 2017				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments - asset	$—	$3,464	$—	$3,464
Derivative financial instruments - liability	$—	$360	$—	$360
Derivative deferred premiums - liability	$—	$—	$2,878	$2,878
December 31, 2016				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments - asset	$—	$1,976	$—	$1,976
Derivative financial instruments - liability	$—	$4,336	$—	$4,336
Derivative deferred premiums - liability	$—	$—	$5,449	$5,449

A summary of the changes in Level 3 fair value measurements for the periods presented are as follows:

	Six Months Ended June 30, 2017	Year Ended December 31, 2016
	(in thousands)	
Balance of Level 3 at beginning of period	$(5,449)	$ (9,973)
Derivative deferred premiums - purchases	—	(516)

Derivative deferred premiums - settlements	2,571	5,040
Balance of Level 3 at end of period	$(2,878)	$ (5,449)

Assets and Liabilities Measured at Fair Value on a Non-recurring Basis

Asset Retirement Obligations

We estimate the fair value of our Asset Retirement Obligations ("ARO") based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for ARO, amounts and timing of settlements, the credit-adjusted risk-free rate to be used and inflation rates. See Note 6 in this section for a summary of changes in ARO.

Acquisitions

The estimated fair values of proved oil and natural gas properties acquired in business combinations are based on a discounted cash flow model and market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates. Based on the unobservable nature of certain of the inputs, the estimated fair value of the oil and natural gas properties acquired is deemed to use Level 3 inputs. See Note 2 in this section for further discussion of the Partnership's acquisitions.

Reserves

We calculate the estimated fair values of reserves and properties 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 reserves, future operating and developmental costs, future commodity prices, a market-based weighted average cost of capital rate and the rate at which future cash flows are discounted to estimate present value. We discount future values by a per annum rate of 10%. We believe this rate approximates our long-term cost of capital and accordingly, is well aligned with our internal business decisions. The underlying commodity prices embedded in our estimated cash flows begin with Level 1 NYMEX-WTI forward curve pricing, less Level 3 assumptions that include location, pricing adjustments and quality differentials.

Impairment

The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. If the carrying value of the long-lived assets exceeds the estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. For the three and six months ended June 30, 2017, we recorded a non-cash impairment expense of approximately $17.7 million primarily at one of our Northeastern Oklahoma projects due to margin compression over the reserve life caused by lower future oil pricing and a higher cost profile at quarter end. For the three and six months ended June 30, 2016, we recorded a non-cash impairment expense of approximately $0.9 million in our Permian core area due to a revision of reserve estimates at one property. These impairment expenses are included in "Impairment of proved oil and natural gas properties" in our unaudited condensed consolidated statements of operations. For the three and six months ended June 30, 2016, we also recorded a non-cash impairment expense of approximately $3.6 million related to the Hugoton core area divestiture to reduce the carrying amount of those assets to their fair value. These assets and liabilities were deemed to meet held for sale accounting criteria as of June 30, 2016, accordingly, the impairment is included in "Impairment of proved oil and natural gas properties sold" in our consolidated statements of operations.

Note 6. Asset Retirement Obligations

We have obligations under our lease agreements and federal regulations to remove equipment and restore land at the end of oil and natural gas operations. These ARO are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or drilling a well and determine our ARO by calculating the present value of estimated cash flow related to the estimated future liability. Determining the removal and future restoration obligation requires management to make estimates and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. We are required to record the fair value of a liability for the ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We review our assumptions and estimates of future ARO on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. The liability is accreted each period toward its future value and is recorded in our unaudited condensed consolidated statements of operations. The discounted capitalized cost is amortized to expense through the depreciation calculation over the life of the assets based on proved developed reserves. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability.

As of June 30, 2017, and December 31, 2016, our ARO were reported as "Asset retirement obligations" in our unaudited condensed consolidated balance sheets. Changes in our ARO for the periods indicated are presented in the following table:

	Six Months Ended June 30, 2017	Year Ended December 31, 2016
	(in thousands)	
Asset retirement obligations - beginning of period	$11,331	$ 12,679
Liabilities incurred for new wells and interest	636	747
Liabilities settled upon plugging and abandoning wells	(17)	—
Liabilities removed upon sale of wells	—	(2,827)
Revision of estimates	(75)	155
Accretion expense	244	577
Asset retirement obligations - end of period	$12,119	$ 11,331

Note 7. Debt

We had outstanding borrowings under our revolving credit facility of $121.0 million and $122.0 million at June 30, 2017, and December 31, 2016, respectively. Our revolving credit facility matures in November 2018.

The borrowing base of our revolving credit facility is collectively determined by our lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary. The borrowing base is subject to scheduled redeterminations in the spring and fall of each year with an additional redetermination, either at our request or at the request of the lenders, during the period between each scheduled borrowing base redetermination. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election, the greater of the prime rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50% and the one month adjusted London Interbank Offered Rate ("LIBOR") plus 1.0%, all of which are subject to a margin that varies from 1.00% to 2.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or the applicable LIBOR plus a margin that varies from 2.00% to 3.75% per annum according to the borrowing base usage. For the three months ended June 30, 2017, the average effective rate was approximately 3.81%. Any unused portion of the borrowing base will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to our unitholders. The revolving credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, leverage ratios and restrictions on certain transactions and payments, including distributions. If we fail to perform our obligations under these and other covenants, the revolving credit commitments may be terminated and any outstanding indebtedness under the credit agreement, together with accrued interest, could be declared immediately due and payable. We were in compliance with these covenants as of and during the six months ended June 30, 2017.

During the spring 2016 semi-annual redetermination and amendment to the credit agreement completed in May 2016, the effective borrowing base as of June 1, 2016, was reduced to $163.0 million and was comprised of a $110.0 million conforming tranche and a permitted overadvance of $53.0 million. The permitted overadvance was scheduled to mature on November 1, 2016.

During August 2016, we completed a non-scheduled redetermination and amendment to the credit agreement in conjunction with our Permian Bolt-On acquisition. Among other changes, this amendment to the credit agreement increased the conforming borrowing base of the Partnership’s revolving credit facility to $140.0 million as of August 11, 2016, modified the definition of “Indebtedness” to exclude the Preferred Units and modified the limitations on restricted payments to specifically provide for the payment of cash distributions on the Preferred Units. The amendment also required that by August 18, 2016, we enter into commodity derivative contracts of not less than 75% of our 2017 projected monthly production and not less than 50% of our 2018 projected monthly production, calculated based on proved developed producing reserves at the time of the agreement. These requirements were satisfied with the execution of additional commodity derivative contracts maturing in 2018. The amendment also required that within 30 days we extend our collateral coverage to include the reserves acquired in the Permian Bolt-On acquisition.

During the fall 2016 semi-annual borrowing base redetermination of our revolving credit facility completed in October 2016, the lender group reaffirmed the existing conforming borrowing base of $140.0 million effective October 28, 2016. There were no changes to the terms or conditions of the credit agreement.

During the spring 2017 semi-annual borrowing base redetermination of our revolving credit facility completed in May 2017, the lender group reaffirmed the Partnership's $140.0 million conforming borrowing base effective May 24, 2017. There were no changes to the terms or conditions of the credit agreement. The next regularly scheduled borrowing base redetermination will occur on or about October 31, 2017.

Note 8. Commitments and Contingencies

Leases

We lease corporate office space in Tulsa, Oklahoma and Abilene, Texas. We were also allocated office rent from Mid-Con Energy Operating through August 2016 for office space in Dallas, Texas. Total lease expenses were approximately $0.1 million each for the three months ended June 30, 2017, and 2016, and approximately $0.1 million and $0.2 million each for the six months ended June 30, 2017 and 2016, respectively. These expenses are included in G&A in our unaudited condensed consolidated statements of operations.

Future minimum lease payments under the non-cancellable operating leases are presented in the following table (in thousands):

Remaining 2017	244
2018	490
2019	413
2020	418
2021	423
Total	$1,988

Services Agreement

We are party to a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides certain services to us including management, administrative and operational services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. See Note 10 in this section for additional information.

Employment Agreements

Our general partner has entered into employment agreements with Charles R. Olmstead, Executive Chairman of the Board and Jeffrey R. Olmstead, President and Chief Executive Officer. The employment agreements automatically renew for one-year terms on August 1st of each year unless either we or the employee gives written notice of termination by at least the preceding February. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities and authority as the Board may specify from time to time, in roles consistent with such positions that are assigned to them. The agreement stipulates that if there is a change of control, termination of employment, with cause or without cause, or death of the executive certain payments will be made to the executive officer. These payments, depending on the reason for termination, currently range from $0.4 million to $0.7 million, including the value of vesting of any outstanding units.

Legal

We are party to various claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management and our General Counsel, the ultimate resolution of all claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our financial position, results of operations or cash flows.

Note 9. Equity

Common Units

At June 30, 2017, and December 31, 2016, the Partnership's equity consisted of 29,944,796 and 29,912,230 common units, respectively, representing approximately a 98.8% limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution Agreement to sell, from time to time through or to the Managers (as defined in the agreement), up to $50.0 million in common units representing limited partner interests. In connection with the Preferred Units purchase agreement described below, the Partnership suspended sales of common units pursuant to the Equity Distribution Agreement effective as of the closing date of the issuance of the Preferred Units until the fifth anniversary thereof, unless the Partnership obtains the consent of a majority of the holders of the outstanding Preferred Units.

Our partnership agreement requires us to distribute all of our available cash on a quarterly basis. Our available cash is our cash on hand at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs, including cash from working capital borrowings. There is no assurance as to the future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors.

As of June 30, 2017, cash distributions to our common units continued to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions and also prohibits us from making common unit cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of common unit cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders.

Preferred Units

On August 11, 2016, we completed a private placement of 11,627,906 Preferred Units for an aggregate offering price of $25.0 million. The Preferred Units were issued at a price of $2.15 per Preferred Unit (the "Unit Purchase Price"). Proceeds from this issuance were used to fund the Permian Bolt-On acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of approximately $24.6 million (net of issuance costs of approximately $0.4 million) in connection with the issuance of Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Preferred Units (approximately $18.6 million) and the beneficial conversion feature (approximately $6.0 million). A beneficial conversion feature is defined as a non-detachable conversion feature that is in the money at the commitment date. Per accounting guidance, we are required to allocate a portion of the proceeds from the Preferred Units to the beneficial conversion feature based on the intrinsic value of the beneficial conversion feature. The intrinsic value is calculated at the commitment date based on the difference between the fair value of the common units at the issuance date (number of common units issuable at conversion multiplied by the per-share value of our common units at the issuance date) and the proceeds attributed to the Preferred Units. We record the accretion attributed to the beneficial conversion feature as a deemed distribution using the effective interest method over the five year period prior to the effective date of the holders conversion right. Accretion of the beneficial conversion feature was approximately $0.2 million and $0.5 million for the three and six months ended June 30, 2017.

The holders of our Preferred Units are entitled to certain rights that are senior to the rights of holders of common units, such as rights to distributions and rights upon liquidation of the Partnership. We pay holders of the Preferred Units a cumulative, quarterly cash distribution on all Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership's existing secured indebtedness prevents the payment of a cash distribution to all holders of the Preferred Units, in kind (additional Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end. As of June 30, 2017, all Preferred Unit distributions have been paid in cash. No payment or distribution on common units for any quarter is permitted prior to the payment in full of the Preferred Units distribution (including any outstanding arrearages). At June 30, 2017, the Partnership had accrued approximately $0.5 million for the second quarter 2017 dividends that are to be paid in August 2017.

The following table summarizes cash distributions paid on our Preferred Units during the six months ended June 30, 2017:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2017	October 1, 2016 - December 31, 2016	$ 0.043	$ 500
May 15, 2017	January 1, 2017 - March 31, 2017	$ 0.043	$ 500

Prior to the five year anniversary of the closing date, each holder of the Preferred Units has the right, subject to certain conditions, to convert all or a portion of their Preferred Units into common units representing limited partner interests in the Partnership on a one-for-one basis, subject to adjustment for splits, subdivisions, combinations and reclassifications of the common units. Upon conversion of Preferred Units, the Partnership will pay any distributions (to the extent accrued and unpaid as of the then most recent Preferred Units distribution date) on the converted units in cash.

Under the registration rights agreements entered into in connection with the Preferred Units issuance, we were required to use reasonable best efforts to file, within 90 days of the closing date, a registration statement registering resales of common units issued or to be issued upon conversion of the Preferred Units and have the registration statement declared effective within 180 days after the closing date. On June 14, 2017, the previously filed shelf registration statement on Form S-3 was declared effective by the SEC.

Allocation of Net Income (Loss)

Net income (loss), net of distributions on the Preferred Units and amortization of the Preferred Unit's beneficial conversion feature (see Preferred Units section), is allocated between our general partner and the limited partner unitholders in proportion to their pro rata ownership (exclusive of the Preferred Units limited partnership interest) during the period. The allocation of net income (loss) is presented in our unaudited condensed consolidated statements of operations. In the event of net income, diluted net income per partner unit reflects the potential dilution of non-vested restricted stock awards and the conversion of Preferred Units.

Note 10. Related Party Transactions

Agreements with Affiliates

The following agreements were negotiated among affiliated parties and, consequently, are not the result of arm's length negotiations. The following is a description of those agreements that have been entered into with the affiliates of our general partner and with our general partner.

Services Agreement

We are party to a services agreement with our affiliate, Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating provides certain services to us, including management, administrative and operational services. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. These expenses are included in G&A in our unaudited condensed consolidated statements of operations.

Operating Agreements

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are parties to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead associated with operating our properties. We and those third parties also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements. The majority of these expenses are included in lease operating expenses (“LOE”) in our unaudited condensed consolidated statements of operations.

Oilfield Services

We are party to operating agreements, pursuant to which our affiliate, Mid-Con Energy Operating, bills us for oilfield services performed by our affiliate, ME3 Oilfield Service. These amounts are either included in LOE in our unaudited condensed consolidated statements of operations or are capitalized as part of oil and natural gas properties in our unaudited condensed consolidated balance sheets.

The following table summarizes the affiliates' transactions for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Amounts paid for:				
Services agreement	$652	$706	$1,293	$1,526
Operating agreements	1,613	1,616	3,016	3,281
Oilfield services	857	825	1,667	1,496
	$3,122	$3,147	$5,976	$6,303

At June 30, 2017, we had a payable to our affiliate, Mid-Con Energy Operating, of approximately $1.4 million, comprised of a joint interest billing payable of approximately $1.2 million and a payable for operating services of approximately $0.2 million. At December 31, 2016, we had a payable to our affiliate, Mid-Con Energy Operating, of approximately $3.4 million, comprised of a joint interest billing payable of approximately $2.8 million and a payable for operating services of approximately $0.6 million. These amounts were included in accounts payable-related parties in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued a comprehensive new revenue recognition standard that supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition. The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring those goods or services. The new standard also requires significantly expanded disclosure regarding the qualitative and quantitative information of an entity's nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The standard creates a five-step model that requires companies to exercise judgment when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard's application impact to individual financial statement line items. This standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. We plan to adopt ASU 2014-09 effective January 1, 2018, using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018, as an adjustment to opening retained earnings. We have completed our initial assessment and concluded that our revenue recognition under the new guidance will not materially differ from our current revenue recognition practice. Therefore, we do not expect a cumulative effect adjustment to opening retained earnings.

In February 2016, the FASB issued ASU No. 2016-02, “Leases (Topic 842),” which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for finance and operating leases. Lease expense recognition on the income statement will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. As of June 30, 2017, the Partnership has not elected early adoption. We believe the primary impact of adopting this standard will be the recognition of assets and liabilities on our balance sheet for current operating leases. We are still evaluating the impact of this standard.

In August, 2016, the FASB issued Accounting Standards Update No. 2016-15, Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). The amendments in ASU 2016-15 address eight specific cash flow issues and apply to all entities that are required to present a statement of cash flows under FASB Accounting Standards Codification (FASB ASC) 230, Statement of Cash Flows. The amendments in ASU 2016-15 are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including adoption during an interim period. As of June 30, 2017, the Partnership has not elected early adoption. Based on our initial evaluation, we do not anticipate a material impact to our consolidated financial statements upon adoption of this standard.

Note 12. Subsequent Events

Distributions

The Board declared a Preferred Unit cash distribution for the second quarter of 2017, according to terms outlined in the Partnership Agreement. A cash distribution of $0.043 per Preferred Unit, or approximately $0.5 million in aggregate, will be paid on August 14, 2017, to holders of record as of the close of business on August 7, 2017.

Equity Awards Issuance

On July 26, 2017, the Board of Directors authorized the issuance of 32,500 equity-settled phantom units, with 27,000 subject to a two-year vesting period and 5,500 subject to a three-year vesting period.

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

Management’s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our unaudited condensed consolidated financial statements and the related notes thereto, as well as our Annual Report.

Overview

Mid-Con Energy Partners, LP is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on EOR. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our common units are traded on the NASDAQ under the symbol “MCEP.”

Our properties are located primarily in the Mid-Continent and Permian Basin regions of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma, and Texas within the Eastern Shelf of the Permian Basin (“Permian”). Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Executive Summary - Second Quarter 2017

Operating Performance

- In the second quarter, the Partnership drilled three producing wells, drilled one injection well, returned one well to production, performed eight recompletions and one capital workover.
- Positive initial waterflood response was observed in the second quarter of 2017 at two Permian properties as a result of new injection. Further waterflood development in these two fields is planned for second half of 2017.
- Production from a new drill producer in our Permian Bolt-On exceeded initial expectations during the second quarter. As a result, the Partnership plans to drill an additional well to expand production and establish water injection in the field during the third quarter of 2017.

Distributions

- On May 15, 2017, we paid a cash distribution on the Preferred Units of approximately $0.5 million, for the first quarter of 2017.

Business Environment

The markets for oil, natural gas and natural gas liquids have been volatile and may continue to be volatile in the future, which means that the price of oil and natural gas may fluctuate widely. Sustained periods of low prices for oil and natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. In general, the average oil and natural gas prices were higher during the comparable periods of 2017 measured against 2016. Our average sales price per barrel of oil ("Bbl"), excluding commodity derivative contracts, was $46.83 per Bbl and $35.59 per Bbl for the six months ended June 30, 2017, and 2016, respectively. The volatility in commodity prices has impacted our unit price. During the six months ended June 30, 2017, our common unit price fluctuated between a closing low of $1.22 per unit to a closing high of $3.22 per unit.

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. We conduct our risk management activities exclusively with participant lenders in our revolving credit facility.

Our business faces the challenge of natural production declines. As initial reservoir pressures are depleted, production from a given well or formation decreases. Although our waterflood operations tend to restore reservoir pressure and production, once a waterflood is fully effected, production, once again, begins to decline. Our future growth will depend on our ability to continue to add reserves in excess of our production. Our focus on adding reserves is primarily through improving the economics of producing oil from our existing fields and, secondarily, through acquisitions of additional proved reserves. Our ability to add reserves through exploitation projects and acquisitions is dependent upon many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and close acquisitions.

We focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flows from operations are impacted by our ability to manage our overall cost structure.

How We Evaluate Our Operations

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which will provide distributions to our unitholders. The amount of cash that we may distribute to our unitholders in the future depends principally on the cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other factors:

- the amount of oil and natural gas we produce;
- the prices at which we sell our oil and natural gas production;
- our ability to hedge commodity prices; and
- the level of our operating and administrative costs.

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas properties, including:

- oil and natural gas production volumes;
- realized prices on the sale of oil and natural gas, including the effect of our commodity derivative contracts;
- LOE; and
- Adjusted EBITDA.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess the cash flow generated by our assets, without regard to financing methods, capital structure or historical cost basis and our ability to incur and service debt and fund capital expenditures.

In addition, management uses Adjusted EBITDA to evaluate actual potential cash flow available to reduce debt, develop existing reserves or acquire additional properties and pay distributions to our unitholders. Adjusted EBITDA is a non-U.S. GAAP measure and should not be considered an alternative to net income (loss), net cash provided by operating activities or any other performance or liquidity measure determined in accordance with U.S. GAAP. In addition, our calculations of Adjusted EBITDA are not necessarily comparable to EBITDA or Adjusted EBITDA as calculated by other companies.

Results of Operations

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated (dollars in thousands, except price per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Revenues:				
Oil sales	$13,657	$14,447	$28,612	$25,553
Natural gas sales	$288	$330	$684	$493
Gain (loss) on derivatives, net	$2,533	$(10,088)	$5,665	$(7,520)
Operating costs and expenses:				
Lease operating expenses	$5,581	$5,777	$10,573	$11,842
Oil and natural gas production taxes	$707	$732	$1,509	$1,324
Impairment of oil and natural gas properties	$17,672	$895	$17,672	$895
Impairment of oil and natural gas properties sold	$—	$3,578	$—	$3,578
Depreciation, depletion and amortization	$4,631	$5,800	$9,500	$11,885
General and administrative [(1)]	$1,471	$1,478	$3,297	$3,566
Interest expense	$1,539	$2,054	$2,989	$4,253
Production:				
Oil (MBbls)	306	349	611	718
Natural gas (MMcf)	110	130	234	260
Total (MBoe)	324	371	650	761
Average net production (Boe/d)	3,560	4,077	3,591	4,181
Average sales price:				
Oil (per Bbl):				
Sales price	$44.63	$41.40	$46.83	$35.59
Effect of net settlements on matured derivative instruments	$(3.21)	$7.82	$(3.95)	$13.50
Realized oil price after derivatives	$41.42	$49.22	$42.88	$49.09
Natural gas (per Mcf):				
Sales price	$2.62	$2.54	$2.92	$1.90
Average unit costs per Boe:				
Lease operating expenses	$17.23	$15.57	$16.27	$15.56
Oil and natural gas production taxes	$2.18	$1.97	$2.32	$1.74
Depreciation, depletion and amortization	$14.29	$15.63	$14.62	$15.62
General and administrative expenses	$4.54	$3.98	$5.07	$4.69

[(1)] G&A included non-cash equity-based compensation of approximately $0.1 million and approximately $0.3 million for the three and six months ended June 30, 2017 and $0.3 million and $0.7 million for the three and six months ended June 30, 2016.

Three Months Ended June 30, 2017 Compared with the Three Months Ended June 30, 2016

We reported net loss of approximately $15.2 million for the three months ended June 30, 2017, compared to a net loss of approximately $15.8 million for the three months ended June 30, 2016. A favorable net impact of derivatives, lower expenses (depreciation, depletion and amortization (“DD&A”), interest and LOE) and higher oil and natural gas prices, partially offset by higher impairment expense and lower oil and natural gas production, were the primary factors attributable to the $0.6 million change.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended June 30, 2017, were approximately $13.9 million compared to approximately $14.8 million for the three months ended June 30, 2016. The revenue decrease was primarily due to lower production volumes. This decrease was partially offset by higher oil and natural gas prices. Our average sales price per Bbl, excluding commodity derivative contracts, for the three months ended June 30, 2017, was approximately $44.63 per Bbl compared to approximately $41.40 per Bbl for the three months ended June 30, 2016.

On average, our production volumes for the three months ended June 30, 2017, were approximately 324 MBoe, or approximately 3,560 Boe per day. In comparison, our total production volumes for the three months ended June 30, 2016, were approximately 371 MBoe, or approximately 4,077 Boe per day. The decrease in production volumes was due to the sale of our Hugoton assets, primary production declines at select properties in the Permian core area, downtime caused by storms in Northeastern Oklahoma and increasing water cuts at select maturing waterflood properties in our Southern Oklahoma core area. Lower production volumes were partially offset by production from the Permian Bolt-On and Wheatland acquisition properties, successful new drill results at a Permian Bolt-On property and positive waterflood responses at key properties in our Permian and Northeastern Oklahoma core areas.

Effects of Commodity Derivative Contracts. For the three months ended June 30, 2017, we recorded a net gain of approximately $2.5 million which was comprised of approximately $2.2 million non-cash gain on changes in fair value of our commodity derivative contracts and approximately $0.3 million gain on net cash settlements of our commodity derivative contracts. For the three months ended June 30, 2016, we recorded a net loss of approximately $10.1 million which was comprised of approximately $16.3 million non-cash loss on changes in fair value of commodity derivative contracts and approximately $6.2 million gain on net cash settlements of derivative contracts.

Lease Operating Expenses. For the three months ended June 30, 2017, LOE was approximately $5.6 million, or approximately $17.23 per Boe, compared to approximately $5.8 million, or approximately $15.57 per Boe, for the three months ended June 30, 2016. The decrease in total LOE for the three months ended June 30, 2017, reflects the impact of the divestiture of properties with higher operating costs, partially offset by incremental costs from the acquisition of properties with lower per Boe operating expenses and increased non-routine costs in Northeastern Oklahoma related to storm damage. The increase in LOE per Boe for the three months ended June 30, 2017, primarily reflects lower production.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues and exclude the effects of our commodity derivative contracts. Production taxes for the three months ended June 30, 2017, were approximately $0.7 million, or approximately $2.18 per Boe (effective tax rate of approximately 5.1%), compared to approximately $0.7 million, or approximately $1.97 per Boe (effective tax rate of approximately 5.0%) for the three months ended June 30, 2016. The increase in production taxes per Boe was due to a tax credit received in May 2016 related to select Permian properties.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the three months ended June 30, 2017, was approximately $4.6 million, or approximately $14.29 per Boe, compared to approximately $5.8 million, or approximately $15.63 per Boe, for the three months ended June 30, 2016. The decrease in total and per Boe DD&A was primarily due to a decrease in depletion rates, offset by the net impact of the Hugoton divestiture and the Permian Bolt-On and Wheatland acquisitions. Depletion rate decreases were driven by both increased reserves and lower production.

Impairment Expense. For the three months ended June 30, 2017, we recorded approximately $17.7 million of non-cash impairment expense primarily at one of our Northeastern Oklahoma projects due to margin compression over the reserve life caused by lower future oil pricing and a higher cost profile at quarter end. For the three months ended June 30, 2016, we recorded approximately $0.9 million of non-cash impairment expense due to revisions in reserve estimates for one of our Permian properties.

General and Administrative Expenses. G&A was approximately $1.5 million, or approximately $4.54 per Boe, for the three months ended June 30, 2017, compared to approximately $1.5 million, or approximately $3.98 per Boe, for three months ended June 30, 2016. The increase in G&A per BOE was primarily due to lower production volumes. G&A expenses included non-cash equity-based compensation of approximately $0.1 million and approximately $0.3 million for the three months ended June 30, 2017 and 2016, respectively.

Interest Expense. Our interest expense for the three months ended June 30, 2017, was approximately $1.5 million, compared to approximately $2.1 million for the three months ended June 30, 2016. The decrease in interest expense during the three months ended June 30, 2017, was due to lower borrowings outstanding and a lower effective interest rate calculated based on borrowing utilization.

Six Months Ended June 30, 2017 Compared with the Six Months Ended June 30, 2016

We reported a net loss of approximately $10.8 million for the six months ended June 30, 2017 compared to a net loss of approximately $19.1 million for the six months ended June 30, 2016. A favorable net impact of derivatives, lower expenses

DD&A, interest and LOE) and higher oil and natural gas prices, partially offset by higher impairment expense and lower oil and natural gas production, were the primary factors attributable to the $8.3 million change.

Sales Revenues. Revenues from oil and natural gas sales for the six months ended June 30, 2017 were approximately $29.3 million as compared to approximately $26.0 million for the six months ended June 30, 2016. For the six months ended June 30, 2017, the revenue increase was primarily due to higher oil and natural gas prices. The increase was partially offset by lower production volumes. Our average sales price per Bbl, excluding commodity derivative contracts, for the six months ended June 30, 2017 was $46.83 per Bbl, compared to approximately $35.59 per Bbl for the six months ended June 30, 2016.

On average, our production volumes for the six months ended June 30, 2017 were approximately 650 MBoe, or approximately 3,591 Boe per day. In comparison, our total production volumes for the six months ended June 30, 2016 were approximately 761 MBoe, or approximately 4,181 Boe per day. The decrease in production volumes was primarily due to the sale of our Hugoton assets, primary production declines at select properties in our Permian core area, downtime caused by storm damage in Northeastern Oklahoma and increasing water cuts at select maturing waterflood properties in our Southern Oklahoma core area. Lower production volumes were partially offset by production from the Permian Bolt-On and Wheatland acquisition properties, successful new drill results at a Permian Bolt-On property and positive waterflood responses at key properties in our Permian and Northeastern Oklahoma core areas.

Effects of Commodity Derivative Contracts. For the six months ended June 30, 2017, we recorded a net gain of approximately $5.7 million which was composed of approximately $5.5 million non-cash gain on changes in fair value of our commodity derivative contracts and approximately $0.2 million gain on net cash settlements of our commodity derivative contracts. For the six months ended June 30, 2016, we recorded a net loss of approximately $7.5 million which was composed of approximately $24.8 million non-cash loss on changes in fair value of our commodity derivative contracts and approximately $17.3 million gain on net cash settlements of our commodity derivative contracts.

Lease Operating Expenses. For the six months ended June 30, 2017, LOE were approximately $10.6 million, or approximately $16.27 per Boe, compared to approximately $11.8 million, or approximately $15.56 per Boe, for the six months ended June 30, 2016. The decrease in total LOE for the six months ended June 30, 2017 reflects the divestiture of Hugoton properties in July 2016, partially offset by incremental costs associated with properties acquired with lower operating expenses and increased non-routine costs in Northeastern Oklahoma related to storm damage. The increase in average costs per Boe, primarily reflects lower production.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas sales revenues and exclude the effects of our commodity derivative contracts. Production taxes for the six months ended June 30, 2017 were approximately $1.5 million, or approximately $2.32 per Boe (effective tax rate of approximately 5.2%), compared to approximately $1.3 million, or approximately $1.74 per Boe (effective tax rate of approximately 5.1%), for the six months ended June 30, 2016. The increase in both production taxes, as a percentage of total sales and per Boe, for the six months ended June 30, 2017 was primarily attributable to tax rebates received during 2016 comparable periods.

Impairment Expense. For the six months ended June 30, 2017, we recorded approximately $17.7 million of non-cash impairment expense primarily at one of our Northeastern Oklahoma projects due to margin compression over the reserve life caused by lower future oil pricing and a higher cost profile at quarter end. For the six months ended June 30, 2016, we recorded approximately $0.9 million of non-cash impairment expense due to revisions in reserve estimates in one of our Permian properties.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the six months ended June 30, 2017, were approximately $9.5 million, or approximately $14.62 per Boe, compared to approximately $11.9

million, or approximately $15.62 per Boe, for the six months ended June 30, 2016. The decrease in total and per Boe DD&A was primarily due to a decrease in depletion rates, offset by the net impact of the Hugoton divestiture and the Permian Bolt-On and Wheatland acquisitions. Depletion rate decreases were driven by both increased reserves and lower production.

General and Administrative Expenses. G&A were approximately $3.3 million or approximately $5.07 per Boe for the for the six months ended June 30, 2017, compared to approximately $3.6 million or approximately $4.69 per Boe for the for the six months ended June 30, 2016. The decrease in G&A for the six months ended June 30, 2017 was primarily due to lower equity-based compensation costs resulting from lower price of our common units and fewer unrestricted and restricted units issued. G&A included noncash equity-based compensation of approximately $0.3 million and approximately $0.7 million for the six months ended June 30, 2017 and 2016, respectively.

Interest Expense. Our interest expense for the six months ended June 30, 2017 was approximately $3.0 million, compared to approximately $4.3 million for the six months ended June 30, 2016. The decrease in interest expense during the six months ended June 30, 2017 is due to lower borrowings outstanding and a lower effective interest rate.

Liquidity and Capital Resources

Our ability to finance our operations, fund our capital expenditures and acquisitions, meet or refinance our debt obligations and meet our collateral requirements will depend on our future cash flows. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, oil and natural gas prices, operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. Historically, our primary use of cash has been for debt reduction, capital spending, including acquisitions, and distributions.

Since November 2014, oil prices have been extremely volatile, impacting the way we conduct business. In response, we have implemented a number of adjustments to strengthen our financial position. We have continued to hedge a portion of our production to limit downside and volatility in the prevailing commodity price environment. We have aggressively pursued cost reductions to improve profitability and maximize cash flows. We further reduced the Partnership's weighted average cash operating break-even costs per Boe with the July 2016 divestiture of our higher cost Hugoton core area and the properties acquired through the August 2016 Permian Bolt-On acquisition, which carry a lower cost profile on a relative basis. Additionally, in the third quarter 2015, we indefinitely suspended our quarterly cash distributions on common units.

Our liquidity position at June 30, 2017, consisted of approximately $0.5 million of available cash and $19.0 million of available borrowings under our revolving credit facility ($140.0 million borrowing base less $121.0 million of outstanding borrowings). Our borrowing base is redetermined in the spring and fall of each year. In May 2017, we completed the spring 2017 semi-annual borrowing base redetermination under our revolving credit facility. The lender group reaffirmed the existing conforming borrowing base of $140.0 million. There were no changes to the terms or conditions of the credit agreement. As of June 30, 2017, we were in compliance with all financial and other covenants of the current credit agreement. Depending on a number of financial and operating factors that can materially influence the cash flow generation of our business, including but not limited to, future oil and natural gas prices, sales from produced oil and natural gas volumes, and cash operating expenses, we could breach certain financial covenants under the revolving credit facility, which would constitute a default under the revolving credit facility. Such default, if not cured, would require a waiver from our lenders to avoid an event of default and, subject to certain limitations, subsequent acceleration of all amounts outstanding under the revolving credit facility and potential foreclosure on our oil and natural gas properties. While no assurances can be made that, in the event of a covenant breach, such a waiver will be granted, we believe the long-term global outlook for commodity prices and our efforts to date will be viewed positively by our lenders. See Note 7 to the unaudited condensed consolidated financial statements for additional information regarding our revolving credit facility.

Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures budget, meet our debt service requirements and fund our other commitments and obligations. Although we currently expect our sources of cash to be sufficient to meet our near-term liquidity needs, there can be no assurance that our liquidity requirements will continue to be satisfied due to the discretion of our lenders to potentially decrease our borrowing base. Due to the volatility of commodity prices, we may not be able to obtain funding in the equity or debt capital markets on terms we find acceptable. The cost of obtaining debt capital from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in some cases, ceased to provide any new funding.

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Cash Flows

Cash flows provided by (used in) each type of activity was as follows (in thousands):

	Six Months Ended June 30,	
	2017	2016
	(in thousands)	
Operating activities	$9,326	$24,899
Investing activities	$(9,140)	$(3,488)
Financing activities	$(2,059)	$(18,007)

Operating Activities. Net cash provided by operating activities was approximately $9.3 million and approximately $24.9 million for the six months ended June 30, 2017, and 2016, respectively. The $15.6 million change from 2016 to 2017 was primarily attributable to lower cash settlements received from matured derivatives.

Investing Activities. Net cash used in investing activities was approximately $9.1 million and approximately $3.5 million for the six months ended June 30, 2017, and 2016, respectively. Cash used in investing activities during the six months ended June 30, 2017, included approximately $4.3 million of capital expenditures for drilling and completion activities primarily in our Permian and Northeastern Oklahoma core areas and approximately $4.7 million for the acquisition of oil and natural gas properties. Cash used in investing activities during the six months ended June 30, 2016, included approximately $3.5 million of capital expenditures for drilling and completion activities primarily in our Permian and Northeastern Oklahoma core areas.

Financing Activities. Net cash used in financing activities was approximately $2.1 million and approximately $18.0 million for the six months ended June 30, 2017, and 2016, respectively. Net cash used in financing activities during the six months ended June 30, 2017, included net payments on our revolving credit facility of approximately $1.0 million and distributions to preferred unitholders of approximately $1.0 million. Net cash used in financing activities during the six months ended June 30, 2016, included payments on our revolving credit facility of approximately $18.0 million.

Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations in order to increase and maintain our production and the size of our asset base. The primary purpose of growth capital is to acquire and develop producing assets that allow us to increase our production and asset base. To date, we have funded acquisition transactions through a combination of cash, available borrowing capacity under our revolving credit facility and through the issuance of equity, including convertible Preferred Units.

We currently expect capital spending for the remainder of 2017 for the development, growth and maintenance of our oil and natural gas properties to be approximately $8.6 million. We will consider adjustments to this capital program as business conditions and operating results warrant, in addition to our ongoing evaluation of additional development opportunities that are identified during the year.

Revolving Credit Facility

At June 30, 2017, our borrowing base was $140.0 million and outstanding borrowings under our revolving credit facility were $121.0 million. Our borrowing base is redetermined in the spring and fall of each year. During the spring 2017 semi-annual redetermination of the revolving credit facility completed in May 2017, the lender group reaffirmed the existing conforming borrowing base of $140.0 million. There were no changes to the terms or conditions of the credit agreement. See Note 7 to the unaudited condensed consolidated financial statements for additional information regarding our revolving credit facility.

Commodity Derivative Contracts

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price or a floor for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. At June 30, 2017, we had commodity derivative contracts covering approximately 73%, 43% and 12%, respectively, of our estimated 2017, 2018 and 2019 average daily production (estimate calculated based on the mid-point of our 2017 Boe production guidance as released on August 2, 2017, and multiplied by a 94% oil weighting based on second quarter 2017 reported production volumes). See Note 4 to the unaudited condensed consolidated financial statements for additional information regarding our commodity derivative contracts.

Preferred Units

During August 2016, we issued $25.0 million of Preferred Units. Preferred unitholders receive a cumulative, quarterly cash distribution on all Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership's existing secured indebtedness prevents the payment of a cash distribution to all holders of the Preferred Units, in kind (additional Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end. See Note 9 to the unaudited condensed consolidated financial statements for additional information regarding Preferred Units.

Off–Balance Sheet Arrangements

As of June 30, 2017, we had no off-balance sheet arrangements.

Recently Issued Accounting Pronouncements

There are no recently issued accounting pronouncements that we expect to materially impact our financial statements. On January 1, 2017, we adopted ASU 2016-09 and elected to recognize forfeitures of equity awards as they occur. The cumulative effect of the change was determined to be immaterial and no adjustment to retained earnings was made. See Note 11 to the unaudited condensed consolidated financial statements for additional information regarding recently issued accounting pronouncements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a variety of market risks including commodity price risk, interest rate risk and credit risk. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Price Risk

Our primary market risk exposure is the pricing we receive for our oil and natural gas sales. Historically, energy prices have exhibited, and are generally expected to continue to exhibit, some of the highest volatility levels observed within the commodity and financial markets. The prices we receive for our oil and natural gas sales depend on many factors outside of our control, such as the strength of the global economy and changes in supply and demand.

Our risk management program is intended to reduce exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivatives contracts (swaps, calls, puts and costless collars), to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders.

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require the counterparties to our commodity derivative contracts to post collateral, it is our policy to enter into commodity derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. We evaluate the credit standing of such counterparties by reviewing their credit ratings. The counterparties to our commodity derivative contracts currently in place are lenders under our revolving credit facility and have investment grade ratings. We expect to enter into future commodity derivative contracts with these or other lenders under our revolving credit facility whom we expect will also carry investment grade ratings.

Our commodity price risk management activities are recorded at fair value and thus changes to the future commodity prices could have the effect of reducing net income and the value of our securities. The fair value of our oil commodity derivative contracts at June 30, 2017, was a net asset of approximately $0.2 million. A 10% change in oil prices, with all other factors held constant, would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil commodity derivative contracts of approximately $3.5 million. See Note 4 to the unaudited condensed consolidated financial statements for additional information regarding our commodity derivative contracts.

Interest Rate Risk

Our exposure to changes in interest rates relates primarily to debt obligations. At June 30, 2017, we had debt outstanding of $121.0 million, with an effective interest rate of 3.69%. Assuming no change in the amount outstanding, the impact on interest expense of a 10% increase or decrease in the average interest rate would be approximately $0.4 million on an annual basis. See Note 7 to the unaudited condensed consolidated financial statements for additional information regarding our revolving credit facility.

Counterparty and Customer Credit Risk

We are subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current production. The inability or failure of any of our customers to meet its obligations to us or its insolvency or liquidation may adversely affect our financial results. We monitor our exposure to these counterparties primarily by reviewing credit ratings and payment history. As of June 30, 2017, our current purchasers had positive payment histories.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our chief executive officer (principal executive officer) and chief financial officer (principal financial officer), the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2017. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on this evaluation, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Form 10-Q.

Changes in Internal Controls Over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the quarterly period ended June 30, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In the course of our ongoing preparations for making management’s report on internal control over financial reporting as required by Section 404 of the Sarbanes-Oxley Act of 2002, from time to time we have identified areas in need of improvement and have taken remedial actions to strengthen the affected controls as appropriate. We make these and other changes to enhance the effectiveness of our internal control over financial reporting, which do not have a material effect on our overall internal control over financial reporting.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

ITEM 1A. RISK FACTORS

There have been no material changes with respect to the risk factors disclosed in our Annual Report for the year ended December 31, 2016.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

The exhibits listed below are filed as part of this Quarterly Report:

Exhibit No.	Exhibit Description
31.1+	Rule 13a-14(a)/ 15(d)- 14(a) Certification of Chief Executive Officer
31.2+	Rule 13a-14(a)/ 15(d)- 14(a) Certification of Chief Financial Officer
32.1+	Section 1350 Certificate of Chief Executive Officer
32.2+	Section 1350 Certificate of Chief Financial Officer
101.INS+	XBRL Instance Document
101.SCH+	XBRL Taxonomy Extension Schema Document
101.CAL+	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF+	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB+	XBRL Taxonomy Extension Label Linkbase Document
101.PRE+	XBRL Taxonomy Extension Presentation Linkbase Document

+Filed herewith

SIGNATURE

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

		MID-CON ENERGY PARTNERS, LP
	By:	Mid-Con Energy GP, LLC, its general partner
August 2, 2017	By:	/s/ Matthew R. Lewis Matthew R. Lewis Chief Financial Officer