Mid-Con Energy Partners, LP
Form 10-Q
August 04, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016
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 x 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 x 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 x
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x
As of August 3, 2016, the registrant had 29,912,230 limited partner units and 360,000 general partner units outstanding.

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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:

- business strategies;
- volatility or continued low or further declining commodity prices;
- 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;
- revisions to oil and natural gas reserves estimates as a result of changes in commodity prices;
- 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;
- effectiveness of risk management activities;
- 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," "continue," "goal," "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 include 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, 2015 ("Annual Report"). This document is available through our website www.midconenergypartners.com or through the Securities and Exchange Commission’s ("SEC") Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. 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 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)

	June 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$4,019	$ 615
Accounts receivable:		
Oil and natural gas sales	5,233	4,551
Other	1,346	5,009
Derivative financial instruments	4,687	24,419
Prepaids and other	427	623
Assets held for sale, net	20,821	—
Total current assets	36,533	35,217
Property and Equipment:		
Oil and natural gas properties, successful efforts method:		
Proved properties	418,260	518,916
Accumulated depletion, depreciation, amortization and impairment	(165,362)	(232,008)
Total property and equipment, net	252,898	286,908
Derivative financial instruments	—	1,144
Other assets	3,202	3,817
Total assets	$292,633	$ 327,086
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$2,290	$ 3,185
Related parties	620	559
Derivative financial instruments	443	—
Accrued liabilities	941	165
Current maturities of long-term debt	52,018	30,000
Liabilities related to assets held for sale	2,821	—
Total current liabilities	59,133	33,909
Derivative financial instruments	1,231	—
Long-term debt	110,000	150,000
Asset retirement obligations	10,219	12,679
Commitments and contingencies		
EQUITY, per accompanying statements:		
Partnership equity:		
General partner interest	(180)	47

Limited partners- 29,784,015 and 29,724,890 units issued and outstanding as of June 30, 2016 and December 31, 2015, respectively.	112,230	130,451
Total equity	112,050	130,498
Total liabilities and equity	$292,633	$ 327,086

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,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues:				
Oil sales	$14,447	$21,244	$25,553	$38,538
Natural gas sales	330	367	493	644
Loss on derivatives, net	(10,088)	(8,871)	(7,520)	(7,227)
Total revenues	4,689	12,740	18,526	31,955
Operating costs and expenses:				
Lease operating expenses	5,777	7,617	11,842	16,532
Oil and natural gas production taxes	732	1,319	1,324	2,428
Impairment of proved oil and natural gas properties	895	—	895	—
Impairment of assets held for sale	3,578	—	3,578	—
Depreciation, depletion and amortization	5,800	8,191	11,885	16,037
Accretion of discount on asset retirement obligations	159	93	316	185
General and administrative	1,478	1,637	3,566	5,278
Total operating costs and expenses	18,419	18,857	33,406	40,460
Gain on sale of oil and natural gas properties	13	—	13	—
Loss from operations	(13,717)	(6,117)	(14,867)	(8,505)
Other income (expense):				
Interest income and other	2	3	38	6
Interest expense	(2,054)	(1,830)	(4,253)	(3,557)
Total other expense	(2,052)	(1,827)	(4,215)	(3,551)
Net loss	$(15,769)	$(7,944)	$(19,082)	$(12,056)
Allocation of net loss:				
General partner's interest in net loss	$(188)	$(95)	$(227)	$(145)
Limited partners’ interest in net loss	$(15,581)	$(7,849)	$(18,855)	$(11,911)
Net loss per limited partner unit:				
Basic and diluted	$(0.52)	$(0.26)	$(0.63)	$(0.40)
Weighted average limited partner units outstanding:				
Limited partner units (basic and diluted)	29,785	29,656	29,777	29,572

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,	
	2016	2015
Cash Flows from Operating Activities:		
Net loss	$(19,082)	$(12,056)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	11,885	16,037
Debt issuance costs amortization	674	559
Accretion of discount on asset retirement obligations	316	185
Impairment of proved oil and natural gas properties	895	—
Impairment of assets held for sale	3,578	—
Mark-to-market on derivatives:		
Loss on derivatives, net	7,520	7,227
Cash settlements received for matured derivatives	17,285	7,183
Cash settlements received for early terminations and modifications of derivatives, net	—	11,069
Cash premiums paid for derivatives, net	(2,257)	(15,266)
Gain on sale of oil and natural gas properties	(13)	—
Non-cash equity-based compensation	650	2,316
Changes in operating assets and liabilities:		
Accounts receivable	(682)	1,031
Other receivables	3,822	3,287
Prepaids and other	146	13
Accounts payable and accrued liabilities	162	(2,807)
Net cash provided by operating activities	24,899	18,778
Cash Flows from Investing Activities:		
Additions to oil and natural gas properties	(3,495)	(8,628)
Acquisitions of oil and natural gas properties	—	(1)
Proceeds from sale of oil and natural gas properties	7	—
Net cash used in investing activities	(3,488)	(8,629)
Cash Flows from Financing Activities:		
Proceeds from line of credit	—	23,000
Payments on line of credit	(17,982)	(28,000)
Offering costs	(16)	(88)
Distributions paid	—	(7,504)
Debt issuance costs	(9)	—
Net cash used in financing activities	(18,007)	(12,592)
Net increase (decrease) in cash and cash equivalents	3,404	(2,443)
Beginning cash and cash equivalents	615	3,232
Ending cash and cash equivalents	$4,019	$789
Supplemental Cash Flow Information:		
Cash paid for interest	$3,700	$3,039
Non-Cash Investing and Financing Activities:		
Accrued capital expenditures - oil and natural gas properties	$338	$477

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)

		Limited Partners		
	General Partner	Units	Amount	Total Equity
Balance, December 31, 2015	$ 47	29,725	$ 130,451	$ 130,498
Equity-based compensation	—	59	650	650
Offering costs	—	—	(16)	(16)
Net loss	(227)	—	(18,855)	(19,082)
Balance, June 30, 2016	$ (180)	29,784	$ 112,230	$ 112,050

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," 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 limited partner units ("common units") are traded 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 included herein have been 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, 2015 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 herein are adequate to make the information not misleading.
The unaudited condensed consolidated financial statements reflect 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 on Form 10-K for the year ended December 31, 2015.
All intercompany transactions and account balances have been eliminated.
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. Our primary use of cash has been for debt reduction and to fund capital spending.
Oil prices have fallen to thirteen-year lows during 2016, impacting the way we conduct business. We have implemented a number of adjustments to strengthen our financial position. In January 2015, we restructured our commodity derivative contracts and subsequently increased our revenue security for 2016 and 2017 by executing additional commodity derivative contracts in November 2015 and April 2016 to provide greater oil price protection over a longer period of time. Additionally, we indefinitely suspended our quarterly cash distributions beginning with the third quarter of 2015. We are also aggressively pursuing cost reductions in order to improve profitability and maximize cash flows. Our primary cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of lease operating expenses and general and administrative expenses.
Our liquidity position at June 30, 2016 consisted of approximately $4.0 million of available cash. Our borrowing base is redetermined in or around April and October of each year. During May 2016, we finalized our spring 2016 redetermination and resulting amendment of the underlying revolving credit facility. The new borrowing base was effective as of June 1, 2016 and was comprised of a $110.0 million conforming tranche and a permitted overadvance of $53.0 million. The permitted overadvance matures on November 1, 2016. In addition, the amendment (i) required the Partnership to provide a monthly excess cash flow report; (ii) required the Partnership to make varied minimum monthly principal payments totaling approximately $1.9 million through October 31, 2016; (iii) reduced the borrowing base to $105.0 million upon the close of the previously announced Hugoton divestiture; (iv) allowed an additional non-scheduled borrowing base redetermination between September 1, 2016 and November 1, 2016 to be requested by any lender; (v) increased the minimum collateral coverage from 90% to 95% of proved reserves (and 100% of PDP reserves); (vi) required the Partnership to unwind and early terminate existing hedges covering

production from July 2016 through September 2016 and add new at-the-market swap contracts to replace these hedge terminations; and (vii) required the net proceeds from the previously announced Hugoton sale and the early termination of hedge contracts to be applied to debt reduction.

Based on our cash balance, forecasted cash flows from operating activities, the early monetization of existing hedges and the closing of the previously announced Hugoton divestiture, 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 given current oil prices and the discretion of our lenders to decrease our borrowing base. Due to the volatility of commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money 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.

Note 2. 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 the members of our general partner (the "Founders") and approved by the Board of Directors of the general partner. 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 November 20, 2015, the Board of Directors of the general partner approved an amendment to the Long-Term Incentive Program that increased the number of common units available for issuance from 1,764,000 to 3,514,000. The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at June 30, 2016:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,183,374)
Restricted units granted, net of forfeitures	(414,814)
Equity-settled phantom units granted, net of forfeitures	(109,500)
Phantom units granted, net of forfeitures	(9,575)
Awards available for future grant	1,796,737

We recognized \$0.3 million and \$0.7 million of total equity-based compensation expense for the three and six months ended June 30, 2016, respectively, and we recognized \$0.4 million and \$2.4 million of total equity-based compensation expense for the three and six months ended June 30, 2015, respectively. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statement of operations.

Unrestricted unit awards

We account for unrestricted awards as equity awards since they are settled by issuing common units. 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. These units were granted to certain directors of our general partner.

Restricted unit awards

We account for restricted awards as equity awards since they will be settled by issuing common units. These units vest over a two or three year period. The compensation expense we recognize associated with our restricted units is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. We did not issue any restricted units during the six months ended June 30, 2016.

A summary of our restricted unit awards for the six months ended June 30, 2016 is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2015	222,833	$ 8.49
Units granted	—	—
Units vested	(95,698)	6.96
Units forfeited	(19,043)	9.11
Outstanding at June 30, 2016	108,092	$ 8.80

As of June 30, 2016, there were approximately $0.5 million of unrecognized compensation costs related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 10 months.

Equity-settled phantom unit awards

We account for equity-settled phantom units as equity awards since these awards will be settled by issuing common units. These 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. The compensation expense we recognize associated with our equity-settled phantom units is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. 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. These units were granted to certain employees of our affiliates.

A summary of our equity-settled phantom unit awards for the six months ended June 30, 2016 is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2015	77,500	$ 2.81
Units granted	24,500	1.01
Units vested	(8,168)	1.16
Units forfeited	(15,500)	1.90
Outstanding at June 30, 2016	78,332	$ 2.73

As of June 30, 2016, there were approximately $0.1 million of unrecognized compensation costs related to equity-settled phantom units. The cost is expected to be recognized over a weighted average period of approximately 1.43 years.

Note 3. 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 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 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. These are presented as derivative financial instruments on our unaudited condensed consolidated financial statements.

At June 30, 2016 and December 31, 2015, our net commodity derivative contracts were in a net asset position with a fair value of approximately $3.0 million and $25.6 million, respectively. All of our commodity derivative contracts are with major financial institutions that are also members of our banking group. 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, 2016, all of our counterparties have performed pursuant to their commodity derivative contracts.

At June 30, 2016 and December 31, 2015, our commodity derivative contracts had maturities that extended through June 2018 and December 2017, respectively, and were comprised of commodity price swap, call, put and collar contracts.
For commodity price swap contracts, at the time of execution the seller agrees to receive a fixed price at maturity in exchange for any gains or losses that might be realized from allowing the price of the underlying commodity to float with the market until maturity. From the perspective of the seller, these instruments limit exposure to price declines below the price fixed by the swap at the expense of participating in any price increases above the price fixed by the swap.
For commodity price call contracts, in return for a premium received, which can be effected at either execution or settlement, the seller is obliged to pay the difference, when positive, between the market price of the underlying commodity at maturity and the strike price. From the perspective of the seller, these instruments provide income via the premium received at the expense of any incremental gains that would have otherwise been received above the strike price.
For commodity price put contracts, in return for a premium paid, which can be effected at either execution or settlement, the purchaser has the right to receive the difference, when positive, between the strike price and the market price of the underlying commodity at maturity. From the perspective of the purchaser, these instruments limit exposure to price declines below the strike price at the expense of premiums paid.
For commodity price collar contracts, a collar is the combination of a put purchased or sold by a party and a call option sold or purchased by the same party. The collar is defined as costless when the value of the option purchased is approximately offset by the value of the option sold.
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 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, 2016, we had the following oil derivatives net positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2016	$ 77.85			1,386	WTI
Puts - 2016		$ 50.00	$ —	1,875	WTI
Collars - 2017		$ 40.00	$ 50.68	658	WTI
Puts - 2017		$ 50.00	$ —	1,932	WTI
Collars - 2018		$ 45.00	$ 58.54	1,326	WTI

At December 31, 2015, we had the following oil derivatives net positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2016	$ 79.98			1,598	WTI
Collars - 2016		$ 50.00	$ 50.00	328	WTI

Puts - 2016	$ 50.00	$ —	1,475	WTI
Puts - 2017	$ 50.00	$ —	1,932	WTI

During the first quarter of 2015, we restructured a significant portion of our existing commodity derivative contracts that were in place at December 31, 2014 and entered into new commodity derivative contracts which extend through September

2016. In connection with the early termination of our commodity derivative contracts, we received net proceeds of approximately $11.1 million. We received approximately $5.9 million from selling calls and paid approximately $19.8 million in premiums to extend the contracts through September 2016. The restructuring also resulted in approximately $4.1 million in deferred premium put options. As of June 30, 2016, we had paid approximately $3.4 million of the deferred premiums in connection with these contract settlements.

In connection with the November 2015 semi-annual redetermination of our borrowing base, we entered into additional commodity derivative contracts resulting in total commodity derivative contracts covering at least 80% of our 2016 projected monthly production and at least 50% of our 2017 projected monthly production, calculated based on Proved Developed Producing reserves. No cash settlements were required and the contracts included deferred premiums of approximately $7.8 million that will be paid through December 2017. As of June 30, 2016, we had paid approximately $0.8 million of the deferred premiums in connection with these contract settlements.

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, 2016 and December 31, 2015:

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
	(in thousands)		
June 30, 2016:			
Assets			
Derivative financial instruments - current asset	$10,598	$ (5,911)	$ 4,687
Derivative financial instruments - long-term asset	2,432	(2,432)	—
Total	$13,030	$ (8,343)	$ 4,687
Liabilities			
Derivative financial instruments - current liability	$(1,037)	$ 594	$ (443)
Derivative deferred premium - current liability	(5,317)	5,317	—
Derivative financial instruments - long-term liability	(1,264)	33	(1,231)
Derivative deferred premium - long-term liability	(2,399)	2,399	—
Total	$(10,017)	$ 8,343	$ (1,674)
Net Asset	$3,013	$ —	$ 3,013

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
	(in thousands)		
December 31, 2015:			
Assets			
Derivative financial instruments - current asset	$29,973	$ (5,554)	$ 24,419
Derivative financial instruments - long-term asset	6,077	(4,933)	1,144
Total	$36,050	$ (10,487)	$ 25,563
Liabilities			
Derivative financial instruments - current liability	$(514)	$ 514	$ —
Derivative deferred premium - current liability	(5,040)	5,040	—
Derivative deferred premium - long-term liability	(4,933)	4,933	—
Total	$(10,487)	$ 10,487	$ —
Net Asset	$25,563	$ —	$ 25,563

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,	
	2016	2015	2016	2015
	(in thousands)			
Net settlements on matured derivatives	$6,191	$2,423	$17,285	$7,183
Net settlements on early terminations and modifications of derivatives	—	—	—	11,069
Change in fair value of derivatives, net	(16,279)	(11,294)	(24,805)	(25,479)
Total loss on derivatives, net	$(10,088)	$(8,871)	$(7,520)	$(7,227)

Note 4. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our balance sheet 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 Measures 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 and put contracts.

Level 3—Financial assets and liabilities for which values are based on prices or valuation techniques 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, 2016 and December 31, 2015.

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 changes in valuation techniques or related inputs for the six months ended June 30, 2016 and for the year ended December 31, 2015.

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. See Note 3 in this section for a summary of our derivative financial instruments.

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

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 5 in this section for a summary of changes in ARO.

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: (i) reserves; (ii) future operating and developmental costs; (iii) future commodity prices; (iv) a market-based weighted average cost of capital rate; and (v) the rate at which future cash flows are discounted to estimate present value. We discount future values by a per annum rate of 10% because we believe this amount 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 are the product of a process that begins with Level 1 NYMEX-WTI forward curve pricing, as well as Level 3 assumptions including: pricing adjustments for estimated location and quality differentials, production costs, capital expenditures, production volumes, decline rates, and estimated reserves. 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 sum of 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.

During the three and six months ended June 30, 2016, we recorded a non-cash impairment charge of approximately $0.9 million due to a revision of reserve estimates for a property in our Permian core area. The impairment is included in "Impairment of proved oil and natural gas properties" in our unaudited condensed consolidated statements of operations. On May 26, 2016, we entered into an agreement to sell our assets in the Hugoton core area. The related assets and liabilities were classified as held for sale in the unaudited condensed consolidated balance sheets at June 30, 2016. In conjunction with this agreement, we recorded a non-cash impairment charge of approximately $3.6 million to reduce the carrying amount of these assets to their fair value, based on the agreed upon sales price of $18.0 million, prior to customary post-closing adjustments. The impairment is included in "Impairment of assets held for sale" in our unaudited condensed consolidated statements of operations. There were no impairment charges for the three and six months ended June 30, 2015.

The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value as of June 30, 2016 and December 31, 2015:

	Level 1 (in thousands)	Level 2	Level 3	Fair Value
June 30, 2016				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments - asset	$ —	$ 13,030	$ —	$ 13,030
Derivative financial instruments - liability	$ —	$ 2,301	$ —	$ 2,301
Derivative deferred premiums - liability	$ —	$ —	$ 7,716	$ 7,716
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Assets held for sale	$ —	$ —	$ 20,821	$ 20,821
Asset retirement obligations	$ —	$ —	$ 51	$ 51
Asset retirement obligations related to assets held for sale	$ —	$ —	$ 2,821	$ 2,821
Impairment of proved oil and natural gas properties	$ —	$ —	$ 895	$ 895
Impairment of assets held for sale	$ —	$ —	$ 3,578	$ 3,578
December 31, 2015				

Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments - asset	$ —	$ 36,050	$ —	$ 36,050
Derivative financial instruments - liability	$ —	$ 514	$ —	$ 514
Derivative deferred premiums - liability	$ —	$ —	$ 9,973	$ 9,973
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Asset retirement obligations	$ —	$ —	$ 4,924	$ 4,924
Impairment of proved oil and natural gas properties	$ —	$ —	$ 103,938	$ 103,938

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

	Six Months Ended June 30, 2016	Year Ended December 31, 2015
	(in thousands)	
Balance of Level 3 at beginning of period	$ (9,973)	$ —
Derivative deferred premiums - purchases	—	(11,914)
Derivative deferred premiums - settlements	2,257	1,941
Balance of Level 3 at end of period	$ (7,716)	$ (9,973)

Note 5. 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 production 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 asset retirement obligations 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

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corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. Over time, 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, 2016 and December 31, 2015, 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, 2016	Year Ended December 31, 2015
	(in thousands)	
Asset retirement obligations - beginning of period	$12,679	$7,363
Liabilities incurred for new wells and interest	51	42
Liabilities settled upon plugging and abandoning wells	—	(40)
Liabilities removed upon sale of wells	(6)	—
Liabilities related to assets held for sale	(2,821)	—
Revision of estimates[1]	—	4,882
Accretion expense	316	432
Asset retirement obligations - end of period	$10,219	$12,679

[1] The revision of estimates that occurred during the year ended December 31, 2015 was primarily due to a change in estimated plugging and abandonment costs based on 2015 settlements.

Note 6. Debt

A summary of our debt at June 30, 2016 and year ended December 31, 2015 is presented below:

	Six Months Ended June 30, 2016	Year Ended December 31, 2015
	(in thousands)	
Revolving credit facility	$162,018	$180,000
Less: current portion	52,018	30,000
Total long-term debt	$110,000	$150,000

At June 30, 2016, we had $162.0 million of borrowings outstanding under our revolving credit facility, comprised of a $110.0 million conforming borrowing base and a $52.0 million permitted overadvance. At June 30, 2016 maturities of our debt were $52.0 million in 2016 and $110.0 million in 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 or around April and October of each year with an additional redetermination, either at our request or at the request of the lender, during the period between each scheduled borrowing base determination. 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: (i) the greater of the prime rate of the 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 (ii) 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, 2016, the average effective rate was approximately 4.13%. 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, 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, 2016.

During February 2015, the revolving credit facility was amended to allow our Consolidated EBITDAX calculation, as defined in section 7.13 of the original revolving credit agreement, to reflect the net cash flows attributable to the restructured commodity derivative contracts that occurred during January 2015 for the periods of the first quarter 2015 through the third quarter of 2016.

During the semi-annual redetermination in April 2015, the borrowing base under the revolving credit facility was reduced to $220.0 million from $240.0 million. No other material terms of the original credit agreement were amended.

During November 2015, the semi-annual redetermination of our borrowing base and amendment of the underlying revolving credit facility was completed. This redetermination resulted in a borrowing base of $190.0 million, consisting of a $165.0 million conforming tranche, which required six monthly commitment reductions of $2.5 million each through May 2016, and a $25.0 million non-conforming tranche that matured on May 1, 2016. The credit facility amendment also designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. This redetermination also required that by December 10, 2015, we enter into commodity derivative contracts of not less than 80% of our 2016 projected monthly production and not less than 50% of our 2017 projected monthly production, calculated based on Proved Developed Producing reserves. These requirements were satisfied during November 2015 with the execution of additional commodity derivative contracts maturing in 2016 and 2017. In connection with this amendment to our revolving credit facility, we incurred financing fees and expenses of approximately $0.7 million, which will be amortized over the remaining life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our unaudited condensed consolidated statements of operations.

During May 2016, we finalized our spring 2016 redetermination and resulting amendment of the underlying revolving credit facility. The new borrowing base was effective as of June 1, 2016 and was comprised of a $110.0 million conforming tranche and a permitted overadvance of $53.0 million. The permitted overadvance matures on November 1, 2016. In addition, the amendment (i) required the Partnership to provide a monthly excess cash flow report; (ii) required the Partnership to make varied minimum monthly principal payments totaling approximately $1.9 million through October 31, 2016; (iii) reduced the borrowing base to $105.0 million upon the close of the previously announced Hugoton divestiture; (iv) allowed an additional non-scheduled borrowing base redetermination between September 1, 2016 and November 1, 2016 to be requested by any lender; (v) increased the minimum collateral coverage from 90% to 95% of proved reserves (and 100% of PDP reserves); (vi) required the Partnership to unwind and early terminate existing hedges covering production from July 2016 through September 2016 and add new at-the-market swap contracts to replace these hedge terminations; and (vii) required the net proceeds from the previously announced Hugoton sale and from the early termination of hedge contracts to be applied to debt reduction.

Note 7. Commitments and Contingencies

We lease corporate office space in Tulsa, Oklahoma and Abilene, Texas. We are also allocated office rent from Mid-Con Energy Operating. Total lease expenses were approximately $0.1 million each for the three months ended June 30, 2016 and 2015, and approximately $0.2 million each for the six months ended June 30, 2016 and 2015, respectively. These expenses are included in general and administrative expenses in our unaudited condensed consolidated statements of operations.

Future minimum lease payments under the non-cancellable operating leases at June 30, 2016 were as follows (in thousands):

Remaining 2016	$257
2017	403
2018	408
2019	413
2020	418
2021	423
Total	$2,322

We have a service agreement with Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating will provide certain services to us, our subsidiaries and our general partner, including management, administrative and operations services, which 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 or on our behalf and other expenses allocated by Mid-Con Energy Operating to us.

Our general partner has entered into employment agreements with the following named employees of our general partner: Jeffrey R. Olmstead, President and Chief Executive Officer, and Charles R. Olmstead, Executive Chairman of the Board. The employment agreements automatically renew for one-year terms unless either we or the employee gives written notice of termination by at least February 1st preceding any such August 1st. 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 of Directors of our general partner 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 $0.3 million to $0.7 million, including the value of vesting of any outstanding units.

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 8. Equity

Common Units

At June 30, 2016 and December 31, 2015, the Partnership's equity consisted of 29,784,015 and 29,724,890 common units, respectively, representing approximately a 98.8% limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution Agreement (the "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. The sales, if any, of common units made under the Agreement will be made by any method permitted by law deemed to be an "at-the-market-offering" as defined in Rule 415 under the Securities Act of 1933, as amended (the "Securities Act"), including without limitation, sales made directly on the NASDAQ, on any other existing trading market for our common units or to or through a market maker. From the period of the original agreement to June 30, 2016, we did not sell any common units.

Cash Distributions

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 August 3, 2016, cash distributions continue to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate distributions and also prohibits us from making 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 of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of 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.

Allocation of Net Income or Loss

Net income or loss is allocated between our general partner and the limited partner unitholders in proportion to their pro rata ownership during the period.

Note 9. 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 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 general and administrative expenses 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 party to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties. We and those third parties 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 in our unaudited condensed consolidated statements of operations.

Oilfield Services. We are party to standard oilfield services operating agreements, pursuant to which Mid-Con Energy Operating bills us for oilfield services performed by our affiliate ME3 Oilfield Service. These expenses are either included in lease operating expenses in our unaudited condensed consolidated statements of operations or in 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,	
	2016	2015	2016	2015
Amounts paid for:	(in thousands)			
Services agreement	$706	$827	$1,526	$1,678
Joint operating agreements	1,616	2,044	3,281	4,158
Oilfield services provided by ME3 Oilfield Service	825	883	1,496	1,913
	$3,147	$3,754	$6,303	$7,749

At June 30, 2016, we had a net payable to Mid-Con Energy Operating of approximately $0.6 million which was comprised of a joint interest billing payable of approximately $0.4 million and a payable for operating services of approximately $0.2 million. These amounts are included in the accounts payable-related parties in our unaudited condensed consolidated balance sheets.

Note 10. 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. The Partnership is currently evaluating the impact this guidance will have on its consolidated financial statements upon adoption of this standard.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. The amendments in ASU 2014-15 are intended to define management's responsibility to evaluate whether there is a substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosures. This standard is effective for the annual periods ending after December 15, 2016, and for interim periods within annual period beginning after December 15, 2016. Early adoption is permitted. As of June 30, 2016 the Partnership has not elected early adoption.

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. The Partnership is currently evaluating the impact this guidance will have on its consolidated financial statements upon adoption of this standard.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting. The guidance simplifies the accounting for employee stock-based payment transactions including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification of awards as either equity or liabilities, and classification of related amounts within the statement of cash flows. The guidance requires the recognition of the income tax effects of awards in the income statement when the awards vest or are settled, thus eliminating additional paid in capital pools. The guidance also allows for the employer to repurchase more of an employee’s shares for tax withholding purposes without triggering liability accounting. In addition, the guidance allows for a policy election to account for forfeitures as they occur rather than on an estimated basis. The guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period and early adoption is permitted. The Partnership is currently evaluating the impact this guidance will have on its consolidated financial statements upon adoption of this standard.

Note 11. Subsequent Events

On July 1, 2016, in connection with our spring 2016 borrowing base redetermination, we terminated some of our commodity derivative contracts covering July 2016 through September 2016 production, resulting in net receipts of approximately $4.3 million. Per the amendment to the credit facility, we used the funds received to reduce our outstanding debt. Also on July 1, 2016, we entered into new commodity derivative at-the-market swap contracts covering 300,000 barrels of future oil production which extend through September 2016.

On July 20, 2016, the Board of Directors authorized the issuance of 3,932 unrestricted units, 323,000 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years, and 27,000 equity-settled phantom units with a three-year vesting period. The equity-settled phantom units do not have any rights or privileges of a unit holder, including right to distributions, until vesting and the resulting conversion into common units. These units were granted to certain employees of our affiliates and founders of our general partner.

On July 28, 2016, we closed on the previously announced sale of oil and natural gas assets within the Hugoton area. The effective date of the sale was May 1, 2016. Proceeds from the sale of approximately $17.9 million, inclusive of preliminary post-closing adjustments, were used to reduce borrowings outstanding under the Partnership's revolving

credit facility. These assets, net of DD&A and impairment, were classified as assets held for sale, net and their corresponding ARO liabilities were classified as liabilities related to assets held for sale in our unaudited condensed consolidated balance sheets at June 30, 2016.
On July 28, 2016, we entered into a definitive purchase and sale agreement to purchase oil and natural gas assets in Nolan County, Texas for an aggregate purchase price of approximately $19.5 million, subject to customary post-closing purchase price

adjustments. The effective date of the acquisition is June 1, 2016 and it is expected to close on or before August 12, 2016. The purchase price will be paid in cash, which is expected to be funded by the Private Offering described below.

On July 28, 2016, as more fully described in the Partnership's Form 8-K filed with the SEC on August 3, 2016, we entered into a definitive agreement to issue and sell $20.0 million of Class A Convertible Preferred Units ("preferred units") in a private offering subject to customary closing conditions with the Partnership having the option to issue and sell an additional $5.0 million in additional preferred units. The Partnership will use the net proceeds from the offering to fund the acquisition of certain properties in Nolan County, Texas, and any excess will be used to reduce borrowings under our revolving credit facility or general corporate purposes. The preferred units will be issued at a price of $2.15 per preferred unit (the "unit purchase price"). The Partnership will pay holders of the preferred units a cumulative, quarterly distribution in cash at an annual rate of 8.0%, or under certain circumstances, in additional preferred units, at an annual rate of 10%. At any time after the six month anniversary and prior to the five year anniversary of the closing date, each holder of the preferred units may elect to convert all or any portion of their preferred units into common units representing limited partner interests in the Partnership on a one-for-one basis. On the fifth anniversary of the closing date of the offering, each holder may elect to cause the Partnership to redeem all or any portion of their preferred units for cash at the unit purchase price, and any remaining preferred units will thereafter be converted to common units on a one-for-one basis. The agreement requires the Partnership to enter into a registration rights agreement and has provisions relating to a change of control. The agreement also requires the Partnership to suspend sales of Common Units pursuant to the Equity Distribution Agreement, which is described in Note 8 in our unaudited condensed consolidated financial statements, from the closing date through the fifth anniversary of the closing date and prohibits the Partnership from incurring any indebtedness (other than under the Partnership's existing credit facility and trade accounts payable arising in the ordinary course of business) without the consent of the majority of the holders of the preferred units.

On July 29, 2016, we entered into new commodity derivative contracts covering 150,000 barrels of future oil production which extend through December 2018.

On August 1, 2016, we entered into new commodity derivative contracts covering 150,000 barrels of future oil production which extend through December 2018.

On August 1, 2016, we announced that effective upon the closing of the Nolan County, Texas asset purchase, we have received unanimous lender support to increase the pro forma conforming borrowing base of our revolving credit facility to $140.0 million subject to execution of Amendment No. 10 to the credit agreement.

As of August 3, 2016, borrowings outstanding under the revolving credit facility were approximately $139.3 million, after total debt payments of approximately $22.7 million from the June 30, 2016 balance.

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 ("we," "our," "us," the "Partnership," 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 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 four core areas: Southern Oklahoma, Northeastern Oklahoma, Texas Gulf Coast and Texas within the Eastern Shelf of the Permian ("Permian"). Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Recent Developments

Operating Performance

Low oil and natural gas prices continue to constrain the Partnership's operating income by negatively impacting top-line revenues and corresponding operating margins. As detailed below, the Partnership has responded to this operating environment

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with numerous cost control initiatives and ongoing portfolio evaluations. During the second quarter 2016, production declined approximately 5% sequentially. Relative to the first quarter 2016, we reduced lease operating expenses approximately 5% while general and administrative costs decreased by approximately 29%, largely due to the year-end audit and K-1 tax preparation fees that occurred during the first quarter. Sequential cash operating expenses declined approximately 3% quarter-over-quarter to average $25.63/Boe. From operating cash flows we repaid approximately $7.0 million in debt during the quarter and funded approximately $1.9 million in capital spending.
Development of our large waterflood projects continued in the second quarter of 2016, notably in our Cleveland Field Unit (Northeastern Oklahoma) and Corsica Bend Conglomerate Unit (Permian). The Cleveland Field Unit continues to demonstrate a strong waterflood response to injection. Additional capital is planned for the remainder of 2016 to further expand the waterflood development at the Cleveland Field Unit. Expansion of our Corsica Bend Conglomerate Unit continued in the second quarter with the addition of a second injection well in an under-developed portion of the Corsica Bend Conglomerate Unit characterized by high oil cuts. Waterflood response from recently established injection is expected in the second half of 2016. Additional development capital is planned for late 2016 and first half of 2017 pending waterflood response in the Bend Conglomerate formation.
In the second quarter of 2016, we drilled and completed two wells, one well in the Northeastern Oklahoma core area and one well in the Permian core area. Nine recompletions (six in the Northeastern Oklahoma core area and three in the Permian core area) targeting behind pipe pay were initiated in the second quarter.

Low Price Environment Initiatives

In response to the significant decline in benchmark oil prices that unfolded since November 2014 and have persisted in 2016, we remain focused on cost reductions. Our ongoing cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of lease operating expenses and general and administrative expenses. Wells that are not economically viable, at prevailing prices, are shut-in provided there are no contractual, operating or reservoir constraints precluding the suspension of operations. Based on this assessment, we elected to shut-in approximately 184 uneconomic wells, the majority of which were shut-in late January 2016, most of which were still shut-in at June 30, 2016. We will continue to monitor pricing and expenses to determine when to return these wells to production.

Commodity Prices

Our revenues and net income are sensitive to oil and natural gas prices which have been and are expected to continue to be volatile. In the second quarter of 2016, the front-month NYMEX-WTI futures price averaged approximately $46 per barrel, compared to approximately $58 per barrel in the second quarter of 2015. During the three months ended June 30, 2016, the front-month NYMEX-WTI futures price ranged from a low of approximately $36 per barrel to a high of approximately $51 per barrel.

Commodity Derivative Contracts

In April 2016, we entered into new oil derivative contracts covering a total of 240,000 barrels of future production which extend from January 2017 through December 2017 with a weighted average ceiling price of $50.68 per barrel and $40.00 floor price per barrel.
In May 2016, we entered into new oil derivative contracts covering a total of 240,000 barrels of future production which extend from January 2018 through June 2018 with a weighted average ceiling price of $58.54 per barrel and $45.00 floor price per barrel.

Distributions

As of August 3, 2016, cash distributions continue to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate distributions and also prohibits us from making 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 of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of 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.

Financing Activities

Effective June 1, 2016, in connection with the semi-annual borrowing base redetermination by the lenders, the borrowing base under our revolving credit facility was reduced to $110.0 million conforming tranche and a $53.0 million permitted overadvance. The permitted overadvance matures on November 1, 2016. In addition, we and our lenders reached an agreement on amending certain terms of our revolving credit facility. See Note 6 to the unaudited condensed consolidated financial statements for additional information regarding our revolving credit facility.

Appointment of Certain Officers

On April 1, 2016, Mr. Charles L. McLawhorn III was named Vice President, General Counsel and Secretary of the General Partner, replacing Mr. Nathan P. Pekar whose resignation was effective on January 8, 2016.

On June 10, 2016, Mr. Matthew R. Lewis was named Vice President and Chief Financial Officer of the General Partner effective August 1, 2016, replacing Mr. Michael D. Peterson whose resignation was effective July 31, 2016.

Relocation of Corporate Headquarters

On June 10, 2016, we announced the relocation of our corporate headquarters from Dallas, Texas to Tulsa, Oklahoma and the closing of our Dallas office.

Business Environment

The markets for oil, natural gas and NGLs have been volatile and may continue to be volatile in the future, which means that the price of oil may fluctuate widely. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil reserves that we can economically produce and our access to capital. Oil and natural gas prices have been subject to significant fluctuations during the past several years. In general, average oil and natural gas prices were significantly lower during the comparable periods of 2016 measured against 2015. For perspective, prices for front month NYMEX-WTI crude oil futures traded within a range of $35.70 and $51.23 per barrel in the second quarter of 2016, ending the quarter at $48.33 per barrel while front month NYMEX Henry Hub natural gas futures traded within a range of $1.90 to $2.92 per MMBtu over the same period, ending the quarter at $2.92 per MMBtu. The continued volatility in commodity prices has had an impact on our unit price. During the six months ended June 30, 2016, our common unit price fluctuated between a closing high of $3.95 to a closing low of $0.78.

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 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 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. We conduct our risk management activities exclusively with participant lenders in our revolving credit facility. In January 2015, we restructured a significant portion of our hedge portfolio to limit downside and volatility due to the then prevailing commodity price environment. In November 2015, April 2016 and May 2016, we entered into additional oil commodity derivative contracts covering a portion of our anticipated oil production in 2016 through 2018.

Our business faces the challenge of natural production declines. As initial reservoir pressures are depleted, oil 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 stability and, over time, growth of distributions to our unitholders. The amount of cash that we can distribute to our unitholders 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;
- Lease operating expenses; 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 oil 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, net cash provided by (used in) 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 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,	
	2016	2015	2016	2015
Revenues:				
Oil sales	$14,447	$21,244	$25,553	$38,538
Natural gas sales	330	367	493	644
Loss on derivatives, net	(10,088)	(8,871)	(7,520)	(7,227)
Operating costs and expenses:				
Lease operating expenses	$5,777	$7,617	$11,842	$16,532
Oil and natural gas production taxes	$732	$1,319	$1,324	$2,428
Impairment of proved oil and natural gas properties	$895	$—	$895	$—
Depreciation, depletion and amortization	$5,800	$8,191	$11,885	$16,037
General and administrative (1)	$1,478	$1,637	$3,566	$5,278
Interest expense	$2,054	$1,830	$4,253	$3,557
Production:				
Oil (MBbls)	349	397	718	788
Natural gas (MMcf)	130	139	260	266
Total (MBoe)	371	420	761	832
Average net production (Boe/d)	4,077	4,615	4,181	4,597
Average sales price:				
Oil (per Bbl):				
Sales price	$41.40	$53.51	$35.59	$48.91
Effect of net settlements on matured derivative instruments (2)	$7.82	$5.50	$13.50	$8.44
Realized oil price after derivatives	$49.22	$59.01	$49.09	$57.35
Natural gas (per Mcf):				
Sales price (3)	$2.54	$2.64	$1.90	$2.42
Average unit costs per Boe:				
Lease operating expenses	$15.57	$18.14	$15.56	$19.87
Oil and natural gas production taxes	$1.97	$3.14	$1.74	$2.92
Depreciation, depletion and amortization	$15.63	$19.50	$15.62	$19.28
General and administrative expenses	$3.98	$3.90	$4.69	$6.34

(1) General and administrative expenses include non-cash equity-based compensation of $0.3 million and $0.7 million for the three and six months ended June 30, 2016; and $0.4 million and $2.3 million for the three and six months ended June 30, 2015.

(2) Effects of net settlements on commodity derivative instruments does not include the $11.1 million received from restructuring the previous oil derivative contracts in January 2015.

(3) Natural gas sales price per Mcf includes the sales of natural gas liquids.

Three Months Ended June 30, 2016 Compared with the Three Months Ended June 30, 2015

We reported net loss of approximately $15.8 million for the three months ended June 30, 2016 compared to net loss of approximately $7.9 million for the three months ended June 30, 2015. The $7.9 million change was attributable to lower oil and natural gas sales prices, lower oil volumes, the unfavorable net effect of our derivatives and higher impairment charges partially offset by lower lease operating expenses ("LOE"), lower depreciation, depletion and amortization expense ("DD&A") and lower production taxes.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended June 30, 2016 were approximately $14.8 million as compared to approximately $21.6 million for the three months ended June 30, 2015. The revenue decrease was primarily due to lower oil and natural gas prices driven by market conditions combined with lower oil sales volumes. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the three months ended June 30, 2016 was approximately $41.40 compared to approximately $53.51 for the three months ended June 30, 2015. Commodity prices continue to be volatile. In the second quarter of 2016, the front-month NYMEX-WTI futures price averaged approximately $46 per barrel, compared to approximately $58 per barrel in the second quarter of 2015. During the three months ended June 30, 2016, the front-month NYMEX-WTI futures price ranged from a low of approximately $36 per barrel to a high of approximately $51 per barrel.

On average, our production volumes for the three months ended June 30, 2016 were approximately 371 MBoe, or approximately 4,077 Boe per day. In comparison, our total production volumes for the three months ended June 30, 2015 were approximately 420 MBoe, or approximately 4,615 Boe per day. The decrease in production volumes was primarily due to the shut-in of uneconomic wells during the first quarter of 2016, the majority of which remained shut-in during the second quarter of 2016, and decreased production due to natural declines of our assets.

Effects of Commodity Derivative Contracts. We utilize NYMEX-WTI derivative contracts to hedge against changes in commodity prices. To the extent the future commodity prices decrease between measurement periods, we will have gains on our commodity derivative contracts, net of deferred premiums. To the extent future commodity prices increase between measurement periods, we will have losses on our commodity derivative contracts, including deferred premiums. For the three months ended June 30, 2016, we recorded a net loss of approximately $10.1 million which was composed 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. For the three months ended June 30, 2015, we recorded a net loss of approximately $8.9 million from our commodity derivative contracts, which was comprised of approximately $11.3 million non-cash loss on changes in fair value of our commodity derivative contracts and approximately $2.4 million gain on net cash settlements of commodity derivative contracts.

Lease Operating Expenses. For the three months ended June 30, 2016, LOE were approximately $5.8 million, or $15.57 per Boe, compared to approximately $7.6 million, or approximately $18.14 per Boe, for the three months ended June 30, 2015. The decrease in total LOE and average costs per Boe for the three months ended June 30, 2016 reflects the impact of company wide cost-savings initiatives including the shut-in of 184 uneconomic wells during the first quarter of 2016. As of June 30, 2016, the majority of these wells remained shut-in for economic reasons.

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, 2016 were approximately $0.7 million, or approximately $1.97 per Boe (effective tax rate of approximately 5.0%), compared to approximately $1.3 million, or approximately $3.14 per Boe (effective tax rate of approximately 6.1%) for the three months ended June 30, 2015. The decrease in production taxes for the three months ended June 30, 2016 was attributable to lower oil and natural gas revenues driven by lower prices and lower sales volumes and to an EOR Production Tax Exemption for one of our Northeastern Oklahoma units. The EOR exemption will extend through March 2018. The decrease in production tax per Boe and the effective tax rate was primarily attributable to a greater proportion of Permian production, which bears a lower state production rate, and the EOR tax exemption in Northeastern Oklahoma.

Impairment Expense. 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. There were no impairment charges for the three ended June 30, 2015.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the three months ended June 30, 2016 were approximately $5.8 million, or approximately $15.63 per Boe, compared to approximately $8.2 million, or approximately $19.50 per Boe, for the three months ended June 30, 2015. The decrease in DD&A and DD&A per Boe was primarily due to the asset impairment recorded in the fourth quarter of 2015 which reduced the carrying value of our oil and natural gas properties.

General and Administrative Expenses ("G&A"). G&A were approximately $1.5 million, or approximately $3.98 per Boe, for the three months ended June 30, 2016, compared to approximately $1.6 million, or approximately $3.90 per Boe, for the three months ended June 30, 2015. The decrease in G&A expenses was primarily due to decreases in equity-based compensation costs resulting from the lower price of our common units and fewer units issued. G&A expenses included non-cash equity-based compensation of approximately $0.3 million and approximately $0.4 million for the three months ended June 30, 2016 and 2015, respectively.
Interest Expense. Interest expense for the three months ended June 30, 2016 was approximately $2.1 million, compared to approximately $1.8 million for the three months ended June 30, 2015. The increase in interest expense during the three months ended June 30, 2016 is due to a higher effective interest rate as a result of the higher pricing grip established during the fall 2015 redetermination.

Six Months Ended June 30, 2016 Compared with the Six Months Ended June 30, 2015
We reported a net loss of approximately $19.1 million for the six months ended June 30, 2016 compared to a net loss of approximately $12.1 million for the six months ended June 30, 2015. The $7.0 million change was primarily attributable to lower oil and natural gas sales prices and lower oil volumes and higher impairment charges, partially offset by lower LOE, lower DD&A, lower G&A, and lower production taxes.

Sales Revenues. Revenues from oil and natural gas sales for the six months ended June 30, 2016 were approximately $26.0 million as compared to approximately $39.2 million for the six months ended June 30, 2015. In 2016, revenues were negatively affected by the volatility of commodity prices and decreased production volumes. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the six months ended June 30, 2016 was $35.59, compared to approximately $48.91 for the six months ended June 30, 2015. In the first six months of 2016, the front-month NYMEX-WTI futures price averaged approximately $40 per barrel, compared to approximately $53 per barrel in the same period of 2015. During the six months ended June 30, 2016, the front-month NYMEX-WTI futures price ranged from a low of approximately $26 per barrel to a high of approximately $51 per barrel.

On average, our production volumes for the six months ended June 30, 2016 were approximately 761 MBoe, or approximately 4,181 Boe per day. In comparison, our total production volumes for the six months ended June 30, 2015 were approximately 832 MBoe, or approximately 4,597 Boe per day. The decrease in production volumes was primarily due to the shut-in of uneconomical wells, the majority of which remained shut-in during the second quarter of 2016, and decreased production due to natural declines of our assets.

Effects of Commodity Derivative Contracts. We utilize NYMEX-WTI derivative contracts to hedge against changes in commodity prices. To the extent the future commodity prices decrease between measurement periods, we will have gains on our commodity derivatives, net of deferred premiums. To the extent future commodity prices increase between measurement periods, we will have losses on our commodity derivatives contracts, including deferred premiums. 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. For the six months ended June 30, 2015, we recorded a net loss from our commodity derivative contracts of approximately $7.2 million, which was composed of approximately $25.5 million non-cash loss on changes in fair value of our commodity derivative contracts and approximately $18.3 million gain on net cash settlements of our commodity derivative contracts ($11.1 million for the early termination of contracts and $7.2 million from settled commodity derivatives contracts). The non-cash loss on changes in fair value of derivative contracts of approximately $25.5 million included an $11.1 million impact of the gain from early termination of the contracts and a $3.6 million gain upon settlement in January 2015 for contracts that were not early terminated or modified, both of which were previously recognized in the results of operations during the year ended December 31, 2014.

Lease Operating Expenses. For the six months ended June 30, 2016, LOE were approximately $11.8 million, or approximately $15.56 per Boe, compared to approximately $16.5 million, or approximately $19.87 per Boe, for the six months ended June 30, 2015. The decrease in total LOE and average cost per Boe for the six months ended June 30, 2016 reflects the operational decision to shut-in 184 uneconomic wells during first quarter 2016. As of June 30, 2016, the majority of these wells remained shut-in for economic reasons.

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, 2016 were approximately $1.3 million, or approximately $1.74 per Boe (effective tax rate of approximately 5.1%), compared to approximately $2.4 million, or approximately $2.92 per Boe (effective tax rate of approximately 6.2%), for the six months ended June 30, 2015. The decrease in production taxes for the six months ended June 30, 2016 was attributable to lower oil and natural gas revenues driven by lower prices and to an EOR Production Tax Exemption for one of our Northeastern Oklahoma units. The EOR exemption will extend through March 2018. The decrease in production tax per Boe and the effective tax rate was primarily attributable to a greater proportion of Permian production, which bears a lower state production tax rate, and the EOR exemption in Northeastern Oklahoma.

Impairment Expense. 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. There were no impairment charges for the six months ended June 30, 2015.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the six months ended June 30, 2016, were approximately $11.9 million, or approximately $15.62 per Boe, compared to approximately $16.0 million, or approximately $19.28 per Boe, for the six months ended June 30, 2015. The decrease in DD&A and DD&A per Boe were primarily due to the asset impairment recorded in the fourth quarter of 2015 which reduced the carrying value of our oil and natural gas properties.

General and Administrative Expenses. G&A were approximately $3.6 million or approximately $4.69 per Boe for the for the six months ended June 30, 2016, compared to approximately $5.3 million, or approximately $6.34 per Boe, for the six months ended June 30, 2015. The decrease in G&A for the six months ended June 30, 2016 was primarily due to lower equity-based compensation costs resulting from lower price of our common units and fewer units issued. G&A included non-cash equity-based compensation of approximately $0.7 million and approximately $2.3 million for the six months ended June 30, 2016 and 2015, respectively.

Interest Expense. Our interest expense for the six months ended June 30, 2016 was approximately $4.3 million, compared to approximately $3.6 million for the six months ended June 30, 2015. The increase in interest expense during the six months ended June 30, 2016 is due to a higher effective interest rate as a result of the higher pricing grip established during the fall 2015 redetermination.

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. Our primary use of cash has been for debt reduction and to fund capital spending.

Oil prices have fallen to thirteen-year lows during 2016, impacting the way we conduct business. We have implemented a number of adjustments to strengthen our financial position. In January 2015, we restructured our commodity derivative contracts and subsequently increased our revenue security for 2016 and 2017 by executing additional commodity derivative contracts in November 2015 and April 2016 to provide greater oil price protection over a longer period of time. Additionally, we indefinitely suspended our quarterly cash distributions beginning with the third quarter of 2015. We are also aggressively pursuing cost reductions in order to improve profitability and maximize cash flows. Our primary cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of lease operating expenses and general and administrative expenses.

Our liquidity position at June 30, 2016 consisted of approximately $4.0 million of available cash. Our borrowing base is redetermined in or around April and October of each year. During May 2016, we finalized our spring 2016 redetermination and resulting amendment of the underlying revolving credit facility. The new borrowing base was effective as of June 1, 2016 and was comprised of a $110.0 million conforming tranche and a permitted overadvance of $53.0 million. The permitted overadvance matures on November 1, 2016. In addition, the amendment (i) required the Partnership to provide a monthly excess cash flow report; (ii) required the Partnership to make varied minimum monthly principal payments totaling approximately $1.9 million through October 31, 2016; (iii) reduced the borrowing base to $105.0 million upon the close of the previously announced Hugoton divestiture; (iv) allowed an additional non-scheduled borrowing base redetermination between September 1, 2016 and November 1, 2016 to be requested by any lender; (v) increased the minimum collateral coverage from 90% to 95% of proved reserves (and 100% of PDP reserves); (vi) required the Partnership to unwind and early terminate existing hedges covering production from July 2016 through September 2016 and add new at-the-market swap contracts to replace these hedge terminations; and (vii) required the net proceeds from the previously announced Hugoton sale and the early termination of hedge contracts to be applied to debt reduction.

Based on our cash balance, forecasted cash flows from operating activities, the early monetization of existing hedges and the closing of the previously announced Hugoton divestiture, 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 given current oil prices and the discretion of our lenders to decrease our borrowing base. Due to the volatility of commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money 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.

Cash Flows

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

	Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Operating activities	$24,899	$18,778
Investing activities	$(3,488)	$(8,629)
Financing activities	$(18,007)	$(12,592)

Operating Activities. Net cash provided by operating activities was approximately $24.9 million and $18.8 million for the six months ended June 30, 2016 and 2015, respectively. The $6.1 million change from 2015 to 2016 was primarily attributable to the positive net impact of our hedging activities, lower LOE due to the shut-in of uneconomic wells and lower production taxes, offset by lower oil sales revenues resulting from lower oil prices and lower production in 2016.

Investing Activities. Net cash used in investing activities was approximately $3.5 million and approximately $8.6 million for the six months ended June 30, 2016 and 2015, respectively. 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. Cash used in investing activities during the six months ended June 30, 2015 included capital expenditures of approximately $8.6 million primarily for drilling and completion activities in our Northeastern Oklahoma and Permian core areas.

Financing Activities. Net cash used in financing activities was approximately $18.0 million and $12.6 million for the six months ended June 30, 2016 and 2015, respectively. 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. Net cash used in financing activities during the six months ended June 30, 2015 included net payments on our revolving credit facility of $5.0 million, cash distributions to unitholders of approximately $7.5 million and approximately $0.1 million of incremental offering costs.

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. Given the current commodity pricing situation, we have limited capital spending to include only the most economically viable development projects. 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.

We currently expect capital spending for the remainder of 2016 for the development, growth and maintenance of our oil and natural gas properties to be approximately $5.0 million. We will consider adjustments to this capital program based on surplus operating cash flows in concert with our evaluation of additional development opportunities that are identified during the year.

Revolving Credit Facility

At June 30, 2016 our borrowing base was $110.0 million, with a permitted overadvance of $52.0 million that matures November 1, 2016, and our outstanding borrowings under the credit facility were approximately $162.0 million.

During May 2016, we finalized our spring 2016 redetermination and resulting amendment of the underlying revolving credit facility. The new borrowing base was effective as of June 1, 2016 and was comprised of a $110.0 million conforming tranche and a permitted overadvance of $53.0 million. The permitted overadvance matures on November 1, 2016. In addition, the amendment (i) required the Partnership to provide a monthly excess cash flow report; (ii) required the Partnership to make varied minimum monthly principal payments totaling approximately $1.9 million through October 31, 2016; (iii) reduced the borrowing base to $105.0 million upon the close of the previously announced Hugoton divestiture; (iv) allowed an additional non-scheduled borrowing base redetermination between September 1, 2016 and November 1, 2016 to be requested by any lender; (v) increased the minimum collateral coverage from 90% to 95% of proved reserves (and 100% of PDP reserves); (vi) required the Partnership to unwind and early terminate existing hedges covering production from July 2016 through September 2016 and add new at-the-market swap contracts to replace these hedge terminations; and (vii) required the net proceeds from the previously announced Hugoton sale and the early termination of hedge contracts to be applied to debt reduction.
See Note 6 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 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 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, 2016, we had commodity derivative contracts covering approximately 81% of the remainder of our 2016 average daily production and approximately 64% and 33%, respectively, of our 2017 and 2018 average daily production (calculated based on the mid-point of our production guidance released on August 1, 2016). At June 30, 2016, our open commodity derivative contracts were in a net asset position with a fair value of approximately $3.0 million.
See Note 3 to the unaudited condensed consolidated financial statements for additional information regarding our commodity derivative contracts.

Off–Balance Sheet Arrangements

As of June 30, 2016, 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. See Note 10 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 (swap, 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, 2016 was a net asset of approximately $3.0 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 $5.2 million. See Note 3 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, 2016, we had debt outstanding of $162.0 million, with an effective interest rate of 4.15%. 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 $0.7 million on an annual basis. At June 30, 2016, our revolving credit facility allowed for borrowings up to $162.0 million bearing interest at a floating rate based on, at our election: (i) the greater of the prime rate of the 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 (ii) the applicable LIBOR plus a margin that varies from 2.00% to 3.75% per annum according to the borrowing base usage. See Note 6 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 2016 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, 2016, 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, 2016. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we filed 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, 2016, 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, 2015.

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 or furnished as part of this Quarterly Report:

Exhibit No.	Exhibit Description
10.1	Amendment No.6 to Credit Agreement, dated as of February 12, 2015, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.01 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on February 17, 2015).
10.2	Amendment No.7 to Credit Agreement, dated as of November 30, 2015, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 1, 2015).
10.3	Amendment No.8 to Credit Agreement, dated as of April 29, 2016, among Mid-Con Energy Properties, LLC, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.3 to Mid-Con Energy Partners, LP's Quarterly Report on Form 10-Q, filed with the SEC on May 2, 2016).
10.4	Amendment No.9 to Credit Agreement, dated as of May 31, 2016, among Mid-Con Energy Properties, LLC, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on June 2, 2016).
10.5	Amendment No. 1 to Mid-Con Energy Partners, LP Long-Term Incentive Program (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the Commission on November 20, 2015).
10.6	Class A Convertible Preferred Unit Purchase Agreement, dated as of July 31, 2016, by and among Mid-Con Energy Partners, LP and the Purchasers named on Schedule A thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K file with the SEC on August 3, 2016).
10.7+	Purchase and Sale Agreement dated as of May 26, 2016, among Mid-Con Energy Properties, LLC, Mid-Con Energy Operating, LLC as sellers, and PO&G Panhandle, LP, as purchaser.
10.8+	Purchase and Sale Agreement, dated as of July 28, 2016, among Mid-Con Energy Properties, LLC, as purchaser, and Walter Exploration Company, JMW LTD, and Wildcat Properties L.P., as sellers.
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

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+ Filed herewith

++ In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this Form 10-Q shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act. The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed."

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 3, 2016	By:	/s/ Matthew R. Lewis Matthew R. Lewis Chief Financial Officer