Mid-Con Energy Partners, LP
Form 10-Q
November 06, 2013

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 September 30, 2013

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)

2501 North Harwood Street, Suite 2410
Dallas, Texas 75201
(Address of principal executive offices and zip code)
(972) 479-5980
(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 November 6, 2013, the registrant had 19,288,562 common 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;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- oil and natural gas reserves;
- technology;
- realized oil and natural gas prices;
- production volumes;
- lease operating expenses;
- general and administrative expenses;
- future operating results;
- 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, "might," "scheduled" and the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the forward-looking events will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in the "Risk Factors" section included in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2012 ("Annual Report"). This document is available through our web site, 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 Ethics, Governance Guidelines, Partnership Agreement 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)

	September 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$659	$1,053
Accounts receivable:		
Oil and gas sales	7,016	6,413
Other	—	603
Derivative financial instruments	101	3,679
Prepaids and other	282	25
Total current assets	8,058	11,773
PROPERTY AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method:		
Proved properties	212,892	167,036
Accumulated depletion, depreciation and amortization	(32,684)	(21,727)
Total property and equipment, net	180,208	145,309
DERIVATIVE FINANCIAL INSTRUMENTS	57	858
OTHER ASSETS	524	650
Total assets	$188,847	$158,590
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$1,571	$2,168
Related parties	2,555	3,036
Derivative financial instruments	1,559	—
Accrued liabilities	113	315
Total current liabilities	5,798	5,519
DERIVATIVE FINANCIAL INSTRUMENTS	396	—
OTHER LONG-TERM LIABILITIES	88	—
LONG-TERM DEBT	112,000	78,000
ASSET RETIREMENT OBLIGATIONS	3,910	2,890
EQUITY, per accompanying statements:		
Partnership equity		
General partner interest	1,713	1,814
Limited partners- 19,288,562 and 18,990,849 units issued and outstanding as of September 30, 2013 and December 31, 2012, respectively	64,942	70,367
Total equity	66,655	72,181
Total liabilities and equity	$188,847	$158,590

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues:				
Oil sales	$22,831	$14,939	$63,755	$43,937
Natural gas sales	151	109	513	462
Net settlements on derivatives	(1,293)	1,211	89	1,980
Gain (loss) on unsettled derivatives, net	(5,501)	(6,103)	(6,334)	3,638
Total revenues	16,188	10,156	58,023	50,017
Operating costs and expenses:				
Lease operating expenses	4,768	2,634	11,859	7,359
Oil and gas production taxes	1,007	585	2,670	1,298
Impairment of proved oil and gas properties	—	1,255	1,578	1,255
Depreciation, depletion and amortization	3,586	2,611	10,957	7,320
Accretion of discount on asset retirement obligations	47	35	124	92
General and administrative	1,630	3,714	9,667	8,583
Total operating costs and expenses	11,038	10,834	36,855	25,907
Income (loss) from operations	5,150	(678)	21,168	24,110
Other income (expense):				
Interest income and other	2	2	6	7
Interest expense	(895)	(461)	(2,320)	(1,164)
Total other expense	(893)	(459)	(2,314)	(1,157)
Net income (loss)	$4,257	$(1,137)	$18,854	$22,953
Computation of net income (loss) per limited partner unit:				
General partners' interest in net income (loss)	$77	$(22)	$346	$455
Limited partners' interest in net income (loss)	$4,180	$(1,115)	$18,508	$22,498
Net income per limited partner unit:				
Basic	$0.22	$(0.06)	$0.96	$1.26
Diluted	$0.22	$(0.06)	$0.96	$1.26
Weighted average limited partner units outstanding:				
Common limited partner units (basic)	19,269	17,933	19,213	17,790
Common limited partner units (diluted)	19,296	17,933	19,219	17,790

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Condensed Consolidated Statements of Cash Flows
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
Cash Flows from Operating Activities:		
Net income	$18,854	$22,953
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	10,957	7,320
Debt placement fee amortization	126	81
Accretion of discount on asset retirement obligations	124	92
Impairment of proved oil and gas properties	1,578	1,255
Loss (gain) on unsettled derivative instruments, net	6,334	(3,638)
Equity-based compensation	5,419	5,194
Changes in operating assets and liabilities:		
Accounts receivable	(603)	(441)
Other receivables	603	(303)
Prepaids and other	(259)	2,300
Accounts payable and accrued liabilities	(648)	2,972
Net cash provided by operating activities	42,485	37,785
Cash Flows from Investing Activities:		
Additions to oil and gas properties	(19,146)	(17,031)
Acquisitions of oil properties	(28,022)	(16,577)
Net cash used in investing activities	(47,168)	(33,608)
Cash Flows from Financing Activities:		
Proceeds from line of credit	87,000	27,000
Payments on line of credit	(53,000)	(12,000)
Distributions paid	(29,711)	(18,348)
Net cash provided by (used in) financing activities	4,289	(3,348)
Net (decrease) increase in cash and cash equivalents	(394)	829
Beginning cash and cash equivalents	1,053	228
Ending cash and cash equivalents	$659	$1,057
Supplemental Cash Flow Information:		
Cash paid for interest	$2,200	$1,014
Non-Cash Investing and Financing Activities:		
Accrued capital expenditures - oil and gas properties	$373	$785

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Condensed Consolidated Statements of Changes in Equity
(in thousands)
(Unaudited)

	General Partner	Limited Partner Units	Limited Partner Amount	Total Equity
Balance, December 31, 2012	$1,814	18,991	$70,367	$72,181
Equity-based compensation	98	298	5,233	5,331
Distributions	(545)	—	(29,166)	(29,711)
Net income	346	—	18,508	18,854
Balance, September 30, 2013	$1,713	19,289	$64,942	$66,655

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP
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") is a publicly held limited partnership that engages in the acquisition, development and production of oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. Our common units are traded on the NASDAQ Global Select Market 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, 2012 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 for the year ended December 31, 2012.
All intercompany transactions and account balances have been eliminated. In the Notes to Unaudited Condensed Consolidated Financial Statements, all dollar and unit amounts in tabulations are in thousands of dollars and units, respectively, unless otherwise indicated.
The condensed consolidated financial statements for previous periods include certain reclassifications to the accounts payable account that were made to conform to current presentation. Such reclassifications have no impact on previously reported total assets, total liabilities, net income or unitholders' capital.
Note 2. Acquisitions
During May 2013, we acquired additional working interests in our Cushing properties located in the Northeastern Oklahoma core area and in certain Southern Oklahoma units. The results of operations of these properties have been included in the unaudited condensed consolidated financial statements since the acquisition date. We paid approximately $27.4 million million in aggregate consideration for the interests and the transaction was accounted for under the acquisition method. The transaction was financed using proceeds from our credit facility.
Note 3. Equity Awards
We have a long-term incentive program (the "Long-Term Incentive Program") for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating, LLC ("Mid-Con Energy Operating"), who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, restricted units, phantom units, distribution equivalent rights granted with phantom units, and other types of awards and it is administered by the members of our general partner (the "Founders") and approved by the Board of Directors of the general partner. The Long-Term Incentive Program permits the grant of awards covering an aggregate of 1,764,000 units under the Form S-8 we filed with the SEC on January 25, 2012. As of September 30, 2013, there were 1,072,438 units available for issuance under the Plan.
In January 2013, we issued 199,500 unrestricted common units ("URUs") to employees, officers, directors and consultants of our general partner and affiliates. Also, in January 2013, we issued 40,001 restricted common units ("RUs") that have a three-year vesting period. The fair market value of both the URUs and RUs was based on the closing price of our common units at the date of the awards, which was $22.41 per unit. The RUs are subject to forfeiture and we assume a 10% forfeiture rate for the RUs to estimate our equity-based compensation expense.

In July 2013, we issued 14,374 URUs and 56,184 RUs to employees, officers, and directors of our general partner and affiliates that have a three-year vesting period. The fair value of both the URUs and RUs was based on the closing price of our common units at the date of the awards, which was $24.89 per unit. During the three months and nine months ended

September 30, 2013, there were 8,346 RUs and 12,346 RUs forfeited, respectively. The RUs are subject to forfeiture and we assume a 10% forfeiture rate for the RUs to estimate our equity-based compensation expense.

Also in July 2013, we issued 50,000 phantom units ("PRUs") through the LTIP to certain employees. The fair value of the PRUs was based on the closing price of our common units at the date of the awards, which was $23.38 per unit. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statement of operations. PRUs represent limited partner interest in us and entitle the holder, upon vesting, to receive the same number of limited partnership units. The phantom units are an incentive based equity award that will be issued to employees or members of the board of directors over a three-year vesting period subject to attaining certain production target levels. The PRUs are not eligible to receive quarterly distributions until they vest into URU's. In lieu of issuing limited partnership units, the committee consisting of the Founders, may elect at its discretion to pay the phantom units in cash equal to the fair market value of the limited partnership units that would otherwise be distributed as of the date of vesting. We accounted for the PRUs as liability awards. The fair value of the PRUs will be determined based on the fair market value of our units at the end of each reporting period discounted for expected distribution payments during the vesting period. The PRUs are subject to forfeiture and we assume a 10% forfeiture rate for the PRUs to estimate the fair market value of the PRUs. Total estimated compensation expense associated with the PRUs is then only recognized when it is deemed probable that the production target levels will be achieved. At September 30, 2013 we believe it is probable that production target levels will be achieved and that all PRUs issued and outstanding will fully vest.

As of September 30, 2013, there was approximately $2.1 million of unrecognized compensation cost related to nonvested RUs. The cost is expected to be recognized over a weighted average period of approximately 2.35 years. Additionally, there was approximately $1.0 million of unrecognized compensation cost related to nonvested PRUs based on the closing price of our common units at September 30, 2013. The cost is expected to be recognized over the next 2.8 years.

The equity-based compensation expense for the three and nine months ended September 30, 2013 was $0.7 million and $5.4 million, respectively, and for the three and nine months ended September 30, 2012 was $2.5 million and $5.2 million, respectively. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statements of operations.

Note 4. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity prices and interest rates and to assist with stabilizing cash flows. Accordingly, we utilize derivative financial instruments to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and the NYMEX futures prices. Our policies do not permit the use of derivatives for speculative purposes. At September 30, 2013, our open positions consisted of crude oil price collar contracts and crude oil price swap contracts. We have elected not to designate any of our positions as cash flow hedges for accounting purposes and, accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in our unaudited condensed consolidated statements of operations. Pursuant to the accounting standard that permits netting of assets and liabilities where the right of offset exists, we present the fair value of derivative financial instruments on a net basis.

As of September 30, 2013, we had the following oil derivative open positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day
Swaps - 2013	$98.34			1,859
Collars - 2013		$97.67	$108.08	293
Swaps - 2014	$93.56			1,973
Swaps - 2015	$90.05			164

Our oil derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, it is our policy to enter into 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 rating. The counterparties to our derivative contracts currently in place are lenders under our credit facility and have investment grade ratings.

The following table summarizes the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in our condensed consolidated balance sheets at September 30, 2013 (in thousands):

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
Assets			
Derivative financial instrument - current asset	$619	$518	$101
Derivative financial instrument - long-term asset	169	112	57
Total	$788	$630	$158
Liabilities			
Derivative financial instrument - current liability	$(2,077)	$(518)	$(1,559)
Derivative financial instrument - long-term liability	(508)	(112)	(396)
Total	$(2,585)	$(630)	$(1,955)
Net liability	$(1,797)	—	$(1,797)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net settlements on derivatives	$(1,293)	$1,211	$89	$1,980
Gain (loss) on unsettled derivatives, net	(5,501)	(6,103)	(6,334)	3,638
Total gain (loss) on derivatives, net	$(6,794)	$(4,892)	$(6,245)	$5,618

Note 5. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our balance sheet for cash, accounts receivable, accounts payable and derivative financial instruments approximate their fair values. The carrying amount of long-term debt under our credit facility approximates fair value because the credit facility’s variable interest rate resets frequently and approximates current market rates available to us.

We account for our oil and gas commodity derivatives at fair value. The fair value of our derivative financial instruments is determined utilizing NYMEX closing prices for the contract period.

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).

Our 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.

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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 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.
Assets and Liabilities Measured at Fair Value on a Recurring Basis
We account for our commodity derivatives at fair value on a recurring basis. We use certain pricing models to determine the fair value of our derivative financial instruments. 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 4 for a summary of our derivative financial instruments.
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis
We estimate the fair value of the asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note 6 for a summary of changes in asset retirement obligations.
We review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds its estimated fair value. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. There were no impairment charges for the three months ended September 30, 2013. During the nine months ended September 30, 2013, we recorded a non-cash impairment charge of $1.6 million within our miscellaneous core area due to a decline in reserve estimates. During the three and nine months ended September 30, 2012, we recorded a non-cash impairment charge of $1.1 million within our miscellaneous core area and a $0.2 million non-cash impairment charge within our Southern Oklahoma core area due to a decline in reserve estimates. The charges are included in impairment of proved oil and gas properties in our unaudited condensed consolidated statements of operations.

The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value as of September 30, 2013 and December 31, 2012 (in thousands):

	Level 1 (in thousands)	Level 2	Level 3
September 30, 2013			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments- asset	$—	$158	$—
Derivative financial instruments- liability	$—	$1,955	$—
Net financial liabilities	$—	$(1,797)	$—
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$—	$—	$896
Impairment of proved oil and gas properties	$—	$—	$1,578
December 31, 2012			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments- asset	$—	$4,537	$—
Derivative financial instruments- liability	$—	$—	$—
Net financial assets	$—	$4,537	$—
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$—	$—	$845
Impairment of proved oil and gas properties	$—	$—	$1,296

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 nine months ended September 30, 2013.

Note 6. Asset Retirement Obligations

Asset retirement obligations ("ARO") are recorded as a liability at their estimated present value at the various assets' inception, with the offsetting charge to oil and gas properties. Periodic accretion of the discounted estimated liability is recorded in the condensed consolidated statement 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.

Our ARO represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their production lives, in accordance with applicable state laws. We determine our ARO by calculating the present value of estimated cash flow related to the liability. Each year we review and, to the extent necessary, revise our ARO estimates.

Changes in our ARO for the periods indicated are presented in the following table:

	Nine Months Ended September 30, (in thousands)	Year Ended December 31, 2012
Asset retirement obligation - beginning of period	$2,890	$1,919
Liabilities incurred for new wells and interests	990	636
Revision of estimates	(94)	209
Accretion expense	124	126
Asset retirement obligation - end of period	$3,910	$2,890

As of September 30, 2013 and December 31, 2012, $3.9 million and $2.9 million, respectively, of our ARO was classified as long-term and was reported as “Asset Retirement Obligations” in our unaudited condensed consolidated balance sheets.

Note 7. Debt

As of September 30, 2013, our credit facility consists of a $250.0 million senior secured revolving facility that expires in December 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiaries. 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. At September 30, 2013, we had approximately $112.0 million of borrowings outstanding under the revolving credit facility. The facility requires us and our subsidiaries to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0, and a current ratio of not less than 1.0 to 1.0.

The 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. 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. As of September 30, 2013, we were in compliance with all debt covenants.

During the 2012 borrowing base determinations, our borrowing base under the credit facility was increased from $75.0 million to $100.0 million and from $100.0 million to $130.0 million, in April and November, respectively. On April 9, 2013, the borrowing base under the credit facility was reaffirmed at $130.0 million. No material terms of the agreement were amended. Borrowings under the facility may not exceed our current borrowing base of $130.0 million. The borrowing base is determined by the 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 on or about April 30 and October 31 of each year with an additional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. 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.

On November 5, 2013, the borrowing base was increased from $130.0 million to $150.0 million and The Bank of Nova Scotia ("Scotiabank") was added to the lender group. Effective with this increase, the maturity terms of our credit facility were extended to November 5, 2018. No other material terms of the original credit agreement were amended.

Borrowings under the credit facility bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of the Royal Bank of Canada, the federal funds effective rate plus 0.50%, or the one month adjusted London Interbank Offered Rate (“LIBOR”) plus 1.0%, all of which are subject to a margin that varies from 0.75% to 1.75% 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 1.75% to 2.75% per annum according to the borrowing base usage. For the three months and nine months ended September 30, 2013, the average effective interest rate was approximately 2.83% and 2.72%, respectively. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

Note 8. Commitment and Contingencies

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.

We are party to various claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management, 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.

Our general partner has entered into employment agreements with certain executive officers. The employment agreements provide for a term that commenced on August 1, 2011 and expires on August 1, 2014, unless earlier terminated, with automatic one-year renewal terms unless either we or the employee gives written notice of termination at least by February 1 preceding any such August 1. 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 him. 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 $1.6 million to $1.9 million, including the value of vesting of any outstanding units.

Note 9. Equity

Common Units

In January and July 2013, we issued 7,994 and 10,405 common units, respectively, related to the vesting of restricted units that were granted in 2012 and vested in January and July 2013.

At September 30, 2013 and December 31, 2012, Partnership’s equity consisted of 19,288,562 and 18,990,849 common units, respectively, representing approximately a 98% limited partnership interest in us.

Cash Distributions

The following sets forth the distributions we paid during the nine months ended September 30, 2013 (in thousands):

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 14, 2013	October 1, 2012 - December 31, 2012	$0.495	$9,697
May 14, 2013	January 1, 2013 - March 31, 2013	$0.505	$9,891
August 14, 2013	April 1, 2013 - June 30, 2013	$0.515	$10,123
			$29,711

On October 23, 2013, the Board of Directors of our general partner declared a quarterly cash distribution for the third quarter of 2013 of $0.515 per unit, or $2.06 on an annualized basis, which will be paid on November 14, 2013 to unitholders of record at the close of business on November 7, 2013. The aggregate amount of the distribution will be approximately $10.1 million.

Allocation of Net Income (Loss)

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

Note 10. Related Party Transactions

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. We, our general partner and its affiliates have entered into the various documents and agreements, which are described below.

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. During the three and nine months ended September 30, 2013, we reimbursed Mid-Con Energy Operating approximately $0.7 and $2.5 million, for direct expenses, respectively. These costs are included in the general and administrative expenses in our unaudited condensed consolidated statements of operations.

Other Transactions with Related Persons

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 gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies, or COPAS fees). These costs are included in lease operating expenses in our unaudited condensed consolidated statements of operations.

At September 30, 2013, we had a payable to Mid-Con Energy Operating of approximately $2.6 million which was comprised of a joint interest billing payable of approximately $2.4 million and a payable for operating services of approximately $0.2 million. At December 31, 2012 we had a payable to Mid-Con Energy Operating of approximately $3.0 million which was comprised of a joint interest billing payable of approximately $2.7 million and a payable for operating services of approximately $0.3 million. These amounts are included in the accounts payable in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2011-11, Disclosures about Offsetting Assets and Liabilities, which requires disclosure of both gross information and net information about derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to master netting arrangements. This information will enable users on an entity's financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position, including the effect or potential effect of rights of set-off associated with certain financial instruments and derivative instruments within the scope of the update. We adopted this guidance on January 1, 2013, and the adoption of this ASU did not have an effect on our condensed consolidated financial statements.

Note 12. Subsequent Events

On October 22, 2013, we entered into a series of oil derivative contracts covering a total of approximately 45,000 barrels of future production between January and March, 2015.

On October 23, 2013, the Board of Directors of our general partner declared a quarterly cash distribution for the third quarter of 2013 of $0.515 per unit, or $2.06 on an annualized basis, which will be paid on November 14, 2013 to unitholders of record at the close of business on November 7, 2013. The aggregate amount of the distribution will be approximately $10.1 million.

On November 5, 2013, the borrowing base was increased from $130.0 million to $150.0 million and Scotiabank was added to the lender group. Effective with this increase, the maturity terms of our secured facility were extended to November 5, 2018. No other material terms of the original credit agreement were amended.

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

We are a Delaware limited partnership focused on the acquisition, exploitation and development of oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our common units are traded on the NASDAQ Global Select Market under the symbol "MCEP".

Our properties are located in the Mid-Continent region of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates. Our reserve base continues to grow through the acquisition of additional working interests in our Cushing properties and the unitization of the Cleveland Field Unit in our Northeastern Oklahoma core area and our continued capital development programs through drilling and completion activities throughout all of our core areas.

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We are an "emerging growth company" as defined in Section 101 of the Jumpstart Our Business Startups Act of 2012, or the JOBS Act.

Quarterly Highlights

On August 14, 2013, we paid a cash distribution to unitholders for the second quarter of 2013 at the rate of $0.515 per unit. The aggregate distribution was approximately $10.1 million.

During the third quarter of 2013 our oil production decreased approximately 71 Boe per day (3%) compared to approximately 2,593 Boe per day on average during the second quarter of 2013. Oil production volumes decreased due to multiple conversions of production wells to injection wells. Furthermore, we experienced delays in planned operations. Of the 20 total wells drilled year-to-date, as of September 30, 2013, eight were undergoing completion operations or waiting on injection permits, power or equipment.

Business Environment

The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future, which means that the price of oil can 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.

Our hedging strategy is to enter into various commodity derivative contracts intended to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program's objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distributions over time, while retaining some ability to participate in upward moves in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher amount of hedged volumes in the near 12 months.

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 and development 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.

Results of Operations

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues:				
Oil sales	$22,831	$14,939	$63,755	$43,937
Natural gas sales	151	109	513	462
Net settlements on derivatives	(1,293)	1,211	89	1,980
Gain (loss) on unsettled derivatives, net	(5,501)	(6,103)	(6,334)	3,638
Total revenues	$16,188	$10,156	$58,023	$50,017
Operating costs and expenses:				
Lease operating expenses	$4,768	$2,634	$11,859	$7,359
Oil and gas production taxes	$1,007	$585	$2,670	$1,298
Impairment of proved oil and gas properties	$—	$1,255	$1,578	$1,255
Depreciation, depletion and amortization	$3,586	$2,611	$10,957	$7,320
General and administrative (1)	$1,630	$3,714	$9,667	$8,583
Interest expense	$895	$461	$2,320	$1,164
Production:				
Oil (MBbls)	227	171	677	475
Natural gas (MMcf)	32	31	105	91
Total (MBoe)	232	176	694	490
Average net production (Boe/d)	2,522	1,913	2,542	1,788
Average sales price:				
Oil (per Bbl):				
Sales price	$100.58	$87.36	$94.17	$92.50
Effect of net settlements on commodity derivative instruments	$(5.70)	$7.08	$0.13	$4.17
Realized oil price after derivatives	$94.88	$94.44	$94.30	$96.67
Natural gas (per Mcf):				
Sales price (2)	$4.72	$3.52	$4.89	$5.08
Average unit costs per Boe:				
Lease operating expenses	$20.55	$14.97	$17.09	$15.02
Oil and gas production taxes	$4.34	$3.32	$3.85	$2.65
Depreciation, depletion and amortization	$15.46	$14.84	$15.79	$14.94
General and administrative expenses	$7.03	$21.10	$13.93	$17.52

(1) General and administrative expenses include non-cash, equity-based compensation of $0.7 million and $5.4 million for the three and nine months ended September 30, 2013; and $2.5 million and $5.2 million for the three and nine months ended September 30, 2012, respectively.

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

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012.

Net income was approximately $4.3 million for the three months ended September 30, 2013, compared to approximately $1.1 million net loss for the three months ended September 30, 2012, an increase of approximately $5.4 million. The increase was primarily attributable to higher oil revenues due to increased production and a higher oil price, no impairment expense and

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lower general and administrative costs, partially offset by higher lease operating expenses during the three months ended September 30, 2013.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended September 30, 2013, were approximately $23.0 million compared to approximately $15.0 million for the three months ended September 30, 2012. The increase in revenues was primarily due to an increase in the volume of daily oil production from our successful drilling efforts and incremental volumes from acquisitions of oil properties and additional working interest in the latter part of 2012 and May 2013 along with a higher oil price.

Our production volumes for the three months ended September 30, 2013, were approximately 232 MBoe, or approximately 2,522 Boe per day on average. In comparison, our total production volumes for the three months ended September 30, 2012, were approximately 176 MBoe, or approximately 1,913 Boe per day on average. The increase in production volumes was primarily the result of ongoing waterflood response to injection and increased infill drilling in our Southern Oklahoma and Hugoton Basin core areas. Furthermore, the acquisition in the second quarter of 2013 of additional working interests in our existing Cushing properties favorably impacted our oil and natural gas production. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the three months ended September 30, 2013, was approximately $100.58, compared with approximately $87.36 for the three months ended September 30, 2012.

Effects of Commodity Derivative Contracts. We utilize NYMEX contracts to hedge against changes in commodity prices. Due to the period change in the mark-to-market value of these contracts, we recorded a net loss of $6.8 million from our commodity hedging instruments for the three months ended September 30, 2013, which was composed of non-cash loss on unsettled derivative contracts of of $5.5 million and a realized loss of $1.3 million. Correspondingly, for the three months ended September 30, 2012, we recorded a net loss from our commodity hedging program of approximately $4.9 million, which was composed of a $6.1 million non-cash loss on unsettled derivative contracts and a realized gain of approximately $1.2 million on net cash settlements of derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately $4.8 million for the three months ended September 30, 2013, or approximately $20.55 per Boe, compared to approximately $2.6 million for the three months ended September 30, 2012, or approximately $14.97 per Boe. The increase in total lease operating expenses over the prior year’s quarter was primarily attributable to the additional number of producing wells resulting from our drilling programs and the acquisition of additional oil properties and working interests acquired in the latter part of 2012 and during 2013. Also, the Hugoton Basin core area properties have a higher lease operating expense per Boe and with the addition of the Clawson Ranch Waterflood Unit in October 2012 lease operating expenses per Boe have increased. Workovers in the Hugoton Basin core area during the three months ended September 30, 2013, along with post-closing lease operating expense adjustments from the May 2013 acquisition and adjustments to administrative overhead rates from the operator have also contributed to the higher lease operating expenses of approximately $0.5 million for the three months ended September 30, 2013.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. For the three months ended September 30, 2013, our production taxes were approximately $1.0 million, or approximately $4.34 per Boe for an effective tax rate of approximately 4.4%, compared to approximately $0.6 million for the three months ended September 30, 2012, or approximately $3.32 per Boe for an effective tax rate of approximately 3.9%. During the three months ended September 30, 2013, both the increase in production taxes and price per Boe, was directly related to higher oil and gas revenues resulting from increased production and higher average sales prices. Although the State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%, a portion of our wells in Oklahoma currently receive a reduced tax rate due to the Enhanced Recovery Project Gross Production Tax Exemption which has been extended to July 2014.

Impairment Expense. There were no impairment charges for the three months ended September 30, 2013. During the three months ended September 30, 2012, we recorded a non-cash impairment charge of $1.1 million within our miscellaneous core area and a $0.2 million non-cash impairment charge within our Southern Oklahoma core area due to a decline in reserve estimates. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may

not be recoverable. If the carrying amount exceeds the property's estimated fair value, we adjust the carrying amount of the property to fair value through a charge to impairment expense.
Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses ("DD&A") on producing properties for the three months ended September 30, 2013, were approximately $3.6 million, or approximately $15.46 per Boe produced, compared to approximately $2.6 million, or approximately $14.84 per Boe produced, for the three months ended September 30, 2012. The increase in depreciation, depletion and amortization expenses was primarily due to an

increase in total asset value of the oil and gas properties from our drilling program, the acquisition of properties and additional working interests in our Hugoton Basin, Southern and Northeastern Oklahoma core areas during 2012 and 2013.

General and Administrative Expenses. Our general and administrative expenses were approximately $1.6 million for the three months ended September 30, 2013, or approximately $7.03 per Boe produced, compared to approximately $3.7 million for the three months ended September 30, 2012 or approximately $21.10 per Boe produced. The overall decrease in general and administrative expenses for the three months ended September 30, 2013 was primarily due to a decrease in compensation costs related to our non-cash equity-based compensation plan. Non-cash equity based compensation was $0.7 million and $2.5 million for the three months ended September 30, 2013 and 2012, respectively. Excluding the impact of non-cash equity-based compensation, G&A would have been $4.22 per Boe and $6.88 per Boe for the three months ended September 30, 2013 and 2012, respectively.

Interest Expense. Our interest expense for the three months ended September 30, 2013, was approximately $0.9 million, compared to $0.5 million for the three months ended September 30, 2012. The increase was due to higher borrowings outstanding from our credit facility during the three months ended September 30, 2013 compared to the three months ended September 30, 2012.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012.

Net income was approximately $18.9 million for the nine months ended September 30, 2013 compared to approximately $23.0 million for the nine months ended September 30, 2012, a decrease of approximately $4.1 million. This decrease primarily reflects the impact of changes in the mark-to-market fair value of our non-cash unsettled derivative contracts, higher depreciation, depletion and amortization expense along with increased operating expenses, partially offset by an increase in oil sales during the nine months ended September 30, 2013, which reflects our continued growth.

Sales Revenues. Revenues from oil and natural gas sales for the nine months ended September 30, 2013 were approximately $64.3 million as compared to approximately $44.4 million for the nine months ended September 30, 2012. The increase in revenues was primarily due to an increase in daily oil production which includes incremental volumes from recent acquisitions of both properties and working interests.

Our production volumes for the nine months ended September 30, 2013 were approximately 694 MBoe, or approximately 2,542 Boe per day. In comparison, our total production volumes for the nine months ended September 30, 2012, were approximately 490 MBoe, or approximately 1,788 Boe per day. The increase in production volumes was primarily due to ongoing waterflood response from injection and our drilling programs in the Southern Oklahoma and Hugoton Basin core areas. Also, the increase in production for the nine months ended September 30, 2013 reflects the favorable impact from various acquisitions of oil properties and additional working interests during 2012 and 2013. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the nine months ended September 30, 2013 was $94.17, compared with $92.50 for the nine months ended September 30, 2012.

During the first nine months of 2013, we drilled a total of 20 wells with 14 being producers and 6 being injectors. Of the 20 total wells drilled, 8 wells were undergoing completion operations or waiting on injection permits, power or equipment as of September 30, 2013.

Effects of Commodity Derivative Contracts. We utilize NYMEX contracts to hedge against changes in commodity prices. Due to the period change in the mark-to-market value of these contracts, we recorded a net loss from our commodity hedging program for the nine months ended September 30, 2013, of approximately $6.2 million, which was composed of a non-cash loss on unsettled derivative contracts of approximately $6.3 million and a gain of approximately $0.1 million on net cash settlements of derivative contracts. For the nine months ended September 30, 2012, we recorded a net gain from our commodity hedging program of approximately $5.6 million, which was composed of a non-cash gain on unsettled derivative contracts of $3.6 million and a gain of approximately $2.0 million on net cash settlements of derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately $11.9 million for the nine months ended September 30, 2013, or $17.09 per Boe, compared to approximately $7.4 million for the nine months ended September 30, 2012, or approximately $15.02 per Boe. The increase in total lease operating expenses was primarily attributable to the additional number of producing wells due to our drilling program and the additional oil properties and working interests acquired during 2012 and 2013. The increase in average costs per Boe was primarily due to the higher costs of operations in our Hugoton Basin and Northeastern Oklahoma areas from acquisitions in October 2012 and May 2013, respectively, due to workovers in both areas in the last nine months

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. Our production taxes were approximately $2.7 million for the nine months ended September 30, 2013, or approximately $3.85 per Boe for an effective tax rate of approximately 4.2%, compared to approximately $1.3 million for the nine months ended September 30, 2012, or approximately $2.65 per Boe for an effective tax rate of approximately 2.8%. The increase in production taxes during the nine months ended September 30, 2013 was directly related to higher oil and gas revenues driven by increased production. During May 2012 we received approximately $0.5 million of prior period production tax adjustments for one of our Southern Oklahoma units. The adjustment was due to the Enhanced Recovery Project Gross Production Tax Exemption and it also resulted in a lower production tax per Boe rate for the nine months ended September 30, 2012.

Although the State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%, a portion of our wells in Oklahoma currently receive a reduced tax rate due to the Enhanced Recovery Project Gross Production Tax Exemption which has been extended to July 2014.

Impairment Expense. Our impairment expense was approximately $1.6 million and $1.3 million for the nine months ended September 30, 2013 and 2012, respectively. We review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If the carrying amount exceeds the property’s estimated fair value, we adjust the carrying amount of the property to fair value through a charge to impairment expense. As a result of declines in reserve estimates, we recorded approximately a $1.6 million non-cash impairment charge within our miscellaneous core area properties for the nine months ended September 30, 2013. During the nine months ended September 30, 2012, we recorded a $1.1 million and $0.2 million non-cash impairment charge within our miscellaneous core area and our Southern Oklahoma core areas, respectively.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses on producing properties for the nine months ended September 30, 2013 were approximately $11.0 million, or approximately $15.79 per Boe produced, compared to approximately $7.3 million, or approximately $14.94 per Boe produced, for the nine months ended September 30, 2012. The increase in depreciation, depletion and amortization expenses was primarily due to the increase in total asset value of the oil and gas properties from our drilling program, the acquisitions of properties and additional working interests in our Hugoton Basin, Southern and Northeastern Oklahoma core areas during 2012 and 2013.

General and Administrative Expenses. Our general and administrative expenses were approximately $9.7 million for the nine months ended September 30, 2013, or approximately $13.93 per Boe produced compared to approximately $8.6 million for the nine months ended September 30, 2012, or approximately $17.52 per Boe produced. The increase in general and administrative expenses for the nine months ended September 30, 2013 was primarily due to compensation costs related to the hiring of additional staff of engineers and technical personnel, higher professional fees necessary to comply with public reporting requirements, which included costs to file a Form S-3 in February 2013, and higher non-cash equity-based compensation costs which were $5.4 million for the nine months ended September 30, 2013 as compared to $5.2 million for the nine months ended September 30, 2012.

Interest Expense. Our interest expense for the nine months ended September 30, 2013 was approximately $2.3 million, compared to approximately $1.2 million for the nine months ended September 30, 2012. The increase was due to higher borrowings outstanding from our credit facility during the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

We believe a strong balance sheet is a necessary pre-requisite for creating sustainable growth in unitholder value. Our liquidity position as of September 30, 2013, consisted of approximately $0.7 million of available cash, and $18.0 million of available borrowings under our credit facility. Our primary use of capital has been for the acquisition and development of oil and natural gas properties. As we pursue profitable reserves and production growth, we continually monitor our liquidity and the credit markets. Additionally, we continue to monitor events and circumstances surrounding each of the lenders in our credit facility.

As of September 30, 2013, our $250.0 million credit facility had a remaining borrowing capacity of $18.0 million ($130.0 million borrowing base less $112.0 million of outstanding borrowings). The borrowing base is re-determined on or about April 30th and October 31st of each year. On November 5, 2013 the borrowing base of our credit facility was increased from $130.0 million to $150.0 million.

Cash Flow

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

	Nine Months Ended September 30,	
	2013	2012
Operating activities	$42,485	$37,785
Investing activities	(47,168)	(33,608)
Financing activities	4,289	(3,348)

Operating Activities. Net cash provided by operating activities was approximately $42.5 million and $37.8 million for the nine months ended September 30, 2013 and 2012, respectively. The $4.7 million increase from 2012 to 2013 was primarily attributable to higher oil and natural gas revenues resulting from increased production, partially offset by higher cash operating expenses. Our net cash provided by operating activities also includes a reduction of $5.3 million associated with changes in working capital items from 2012 to 2013. Changes in working capital items adjust for the timing of receipts and payments of actual cash. Cash provided by operating activities is impacted by the prices we receive for oil and natural gas sales and production volumes. Our production volumes in the future will in large part be dependent upon the results of past waterflood development activities, increase production through our drilling programs, acquisitions, and results of future capital expenditures.

Investing Activities. Net cash used in investing activities was approximately $47.2 million and approximately $33.6 million for the nine months ended September 30, 2013 and 2012, respectively. Cash used in investing activities during the nine months ended September 30, 2013 included $28.0 million for the purchase of additional working interest in the Cushing properties and certain Southern Oklahoma properties. We also spent $19.1 million on capital expenditures, primarily for drilling, development and completion activities. Cash used in investing activities during the nine months ended September 30, 2012 included $16.6 million for the purchase of certain oil properties in Northeastern Oklahoma and additional working interests in our existing units in Southern Oklahoma. We also spent $17.0 million on capital expenditures, primarily for drilling activities.

Financing Activities. Our cash flows from financing activities consisted primarily of proceeds from and payments on our credit facility, and distributions to unitholders. Net cash provided by financing activities was approximately $4.3 million and net cash used in financing activities was approximately $3.3 million for the nine months ended September 30, 2013 and 2012, respectively. During the nine months ended September 30, 2013, cash provided by financing activities included net proceeds of approximately $34.0 million from borrowings under our credit facility which were used to finance the acquisition of additional working interests in our Northeastern Oklahoma and Southern Oklahoma core areas, and to develop capital projects. Conversely, we made cash distributions to our unitholders of approximately $29.7 million. Cash used by financing activities during the nine months ended September 30, 2012, included net proceeds from borrowings under our credit facility of $15.0 million which were used to finance the purchase of certain oil properties located in our Northeastern Oklahoma core area and certain working interests in our existing units in the Southern Oklahoma core area and to develop capital projects. Conversely, we made cash distributions to our unitholders of approximately $18.3 million.

Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations in order to increase and maintain our production and the size of our asset base. The primary purpose of growth capital is to acquire, develop and produce assets that allow us to increase our production levels and asset base. To date, we have funded acquisition transactions through a combination of cash and available borrowing capacity under our current credit facility. We expect to finance any significant acquisition of oil and natural gas properties in 2013 through the issuance of equity, debt financing or borrowings under our credit facility. Additionally, we currently expect capital spending for the remainder of 2013 for the development, growth and maintenance of our oil and natural gas properties to be approximately $6.4 million.

Credit Facility

We have a $250.0 million senior secured revolving credit facility that expires in December 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiaries. 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. At September 30, 2013, we had approximately $112.0 million of borrowings outstanding under the revolving credit facility. The facility requires us and our subsidiaries to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0, and a current ratio of not less than 1.0 to 1.0. As of September 30, 2013, we were in compliance with all of the facility's financial covenants.

During 2012, our borrowing base under the credit facility was increased from $75.0 million to $100.0 million and from $100.0 million to $130.0 million, in April and November, respectively. On April 9, 2013, the borrowing base under the credit facility was reaffirmed at $130.0 million. No material terms of the agreement were amended. Borrowings under the facility may not exceed our current borrowing base of $130.0 million. The borrowing base is determined by the lenders based on our oil and natural gas reserves.

On November 5, 2013, the borrowing base under the credit facility was increased from $130.0 million to $150.0 million and Scotiabank was added to the lender group. Effective with this increase, the maturity terms of our credit facility were extended to November 5, 2018. No other material terms of the original credit agreement were amended.

For additional information about our long-term debt, such as interest rates and covenants, please see "Item 1. Financial Statements" contained herein.

Derivative Contracts

At September 30, 2013, our open commodity derivative contracts were in a net liability position with a fair value of approximately $1.8 million. All of our commodity derivative contracts are with major financial institutions. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments in the event of lower commodity prices and we could incur a loss. As of September 30, 2013, all of our counterparties had performed pursuant to their commodity derivative contracts.

All of our derivative contracts for 2013, 2014 and 2015 are either swaps with fixed settlements or collars. These instruments limit our exposure to declines in prices, but also limit the benefits if prices increase. We do not specifically designate commodity derivative contracts as cash flow hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of unsettled derivative contracts is recorded in current period earnings as a non-cash gain or loss. When prices for oil are volatile, a significant portion of the effect of our hedging activities consists of non-cash income or expenses due to changes in the fair value of our commodity derivative contracts. Net settlement gains or losses on derivative contracts only arise from net payments made or received on monthly settlements or if a commodity derivative contract is terminated prior to its expiration.

See Note 4 to the unaudited condensed consolidated financial statements within this report for a discussion of our derivative contracts.

Off–Balance Sheet Arrangements

As of September 30, 2013, we had no off–balance sheet arrangements.

Recently Issued Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2011-11, Disclosures about Offsetting Assets and Liabilities, which requires disclosure of both gross information and net information about derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to master netting arrangements. This information will enable users on an entity's financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position, including the effect or potential effect of rights of set-off associated with certain financial instruments and derivative instruments within the scope of the update. We adopted this guidance on January 1, 2013, and the adoption of this ASU did not have an effect on our condensed consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business.

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The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

The following should be read in conjunction with the financial statements and related notes included elsewhere in this Form10-Q and in our Annual Report.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil production. Realized pricing is primarily driven by the spot market prices applicable to the prevailing price for oil. Pricing for oil has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into commodity derivative contracts with respect to a significant portion of our projected oil production through various transactions that fix the future prices received. These hedging activities are intended to manage our exposure to oil price fluctuations. We do not enter into derivative contracts for speculative trading purposes.

Our oil derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, it is our policy to enter into 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 derivative contracts currently in place are lenders under our credit facility and have investment grade ratings. We expect to enter into future derivative contracts with these or other lenders under our credit facility whom we expect will also carry investment grade ratings.

The fair value of our oil commodity contracts and swaps at September 30, 2013, was a net liability of approximately \$1.8 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 contracts and swaps of approximately \$9.0 million. Please see "Item 1. Financial Statements" contained herein for additional information.

Interest Rate Risk

At September 30, 2013, we had long-term debt outstanding of \$112.0 million, with an effective interest rate of approximately 2.72%. 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 \$0.3 million on an annual basis. Our revolving credit facility allows borrowings up to \$130.0 million at an interest rate ranging from LIBOR plus 1.75% to LIBOR plus 2.75% or the prime rate plus 0.75% to the prime rate plus 1.75%, depending on the amount borrowed. The prime rate will be the United States prime rate as announced from time-to-time by the Royal Bank of Canada. Please see "Item 1. Financial Statements" contained herein for additional information.

Counterparty and Customer Credit Risk

We were subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current 2013 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. However, our current purchasers have 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 September 30, 2013. 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 September 30, 2013, 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, 2012.
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	Agreement and Amendment No.3 to Credit Agreement, dated as of November 5, 2013, 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 November 6, 2013).
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
November 6, 2013	By:	/s/ Jeffrey R. Olmstead Jeffrey R. Olmstead President and Chief Financial Officer