Mid-Con Energy Partners, LP
Form 10-Q
November 05, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2018

OR

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

Mid-Con Energy Partners, LP

(Exact name of registrant as specified in its charter)

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

2431 East 61st Street, Suite 850

Tulsa, Oklahoma 74136

(Address of principal executive offices and zip code)

(918) 743-7575

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes No

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

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
Emerging Growth Company	

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

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

As of November 5, 2018, the registrant had 30,436,124 common 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:

- volatility of commodity prices;
- revisions to oil and natural gas reserves estimates as a result of changes in commodity prices;
- effectiveness of risk management activities;
- business strategies;
- future financial and operating results;
- our ability to pay distributions;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- 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;
- future capital requirements and availability and terms of capital;
- marketing of oil and natural gas;
- general economic conditions;
- competition in the oil and natural gas industry;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation;
- developments in oil producing and natural gas producing countries; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 1. “Financial Statements,” Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and other items within this Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “ “forecast,” “guidance,” “might,” “scheduled” and the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this Form 10-Q are not guarantees of future performance and we cannot assure any reader that such statements will be realized or that the forward-looking events will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in the "Risk Factors" section included in Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2017 ("Annual Report") and Part II - Item 1A. in this Form 10-Q. All forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

INFORMATION AVAILABLE ON OUR WEBSITE

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

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, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 126	$ 1,832
Accounts receivable		
Oil and natural gas sales	7,725	5,262
Other	1,617	103
Prepaid expenses and other	242	166
Assets held for sale, net	430	2,058
Total current assets	10,140	9,421
Property and equipment		
Oil and natural gas properties, successful efforts method		
Proved properties	391,560	335,796
Unproved properties	1,564	369
Other property and equipment	427	427
Accumulated depletion, depreciation, amortization and impairment	(149,393)	(129,101)
Total property and equipment, net	244,158	207,491
Other assets	1,599	2,451
Total assets	$ 255,897	$ 219,363
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,048	$ 593
Related parties	4,507	1,631
Derivative financial instruments	10,644	4,252
Accrued liabilities	2,011	603
Liabilities related to assets held for sale	—	77
Total current liabilities	18,210	7,156
Derivative financial instruments	7,326	666
Long-term debt	96,000	99,000
Other long-term liabilities	52	70
Asset retirement obligations	39,192	10,249

Commitments and contingencies		
Class A convertible preferred units - 11,627,906 issued and outstanding, respectively	21,411	20,534
Class B convertible preferred units - 9,803,921 and 0 issued and outstanding, respectively	14,587	—
Equity, per accompanying statements		
General partner	(815)	(572)
Limited partners - 30,436,124 and 30,090,463 units issued and outstanding, respectively	59,934	82,260
Total equity	59,119	81,688
Total liabilities, convertible preferred units and equity	$255,897	$ 219,363

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,	
	2018	2017	2018	2017
Revenues				
Oil sales	$18,765	$13,731	$49,240	$42,343
Natural gas sales	380	233	812	917
Other operating revenues	320	—	320	—
(Loss) gain on derivatives, net	(6,358)	(2,749)	(19,240)	2,916
Total revenues	13,107	11,215	31,132	46,176
Operating costs and expenses				
Lease operating expenses	6,654	6,122	16,706	16,695
Oil and natural gas production taxes	1,157	857	2,992	2,366
Other operating expenses	288	—	288	—
Impairment of proved oil and natural gas properties	—	4,850	9,710	22,522
Depreciation, depletion and amortization	4,812	4,350	11,646	13,850
Dry holes and abandonments of unproved properties	10	—	195	—
Accretion of discount on asset retirement obligations	404	142	748	386
General and administrative	1,494	1,188	4,746	4,485
Total operating costs and expenses	14,819	17,509	47,031	60,304
Loss on sales of oil and natural gas properties, net	(1)	—	(389)	—
Loss from operations	(1,713)	(6,294)	(16,288)	(14,128)
Other (expense) income				
Interest income	1	3	3	8
Interest expense	(1,620)	(1,626)	(4,369)	(4,615)
Other income	20	4	20	70
(Loss) gain on settlements of asset retirement obligations	(37)	(8)	12	(13)
Total other expense	(1,636)	(1,627)	(4,334)	(4,550)
Net loss	(3,349)	(7,921)	(20,622)	(18,678)
Less: Distributions to preferred unitholders	1,148	783	3,303	2,275
Less: General partner's interest in net loss	(39)	(94)	(243)	(222)
Limited partners' interest in net loss	$(4,458)	$(8,610)	$(23,682)	$(20,731)
Limited partners' interest in net loss per unit				
Basic and diluted	$(0.14)	$(0.29)	$(0.78)	$(0.69)
Weighted average limited partner units outstanding				
Limited partner units (basic and diluted)	30,392	30,042	30,292	29,972

See accompanying notes to condensed consolidated financial statements

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Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Cash Flows

(in thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
Cash Flows from Operating Activities		
Net loss	$(20,622)	$(18,678)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	11,646	13,850
Debt issuance costs amortization	503	1,023
Accretion of discount on asset retirement obligations	748	386
Impairment of proved oil and natural gas properties	9,710	22,522
Dry holes and abandonments of unproved properties	195	—
(Gain) loss on settlements of asset retirement obligations	(12)	13
Cash paid for settlements of asset retirement obligations	(102)	(30)
Mark to market on derivatives		
Loss (gain) on derivatives, net	19,240	(2,916)
Cash settlements (paid) received for matured derivatives	(5,988)	524
Cash settlements received from early termination of derivatives	—	147
Cash premiums paid for derivatives	(200)	(5,009)
Loss on sales of oil and natural gas properties	389	—
Non-cash equity-based compensation	670	409
Changes in operating assets and liabilities		
Accounts receivable	(2,463)	697
Other receivables	(646)	150
Prepaids and other	(76)	363
Accounts payable - trade and accrued liabilities	689	1,009
Accounts payable - related parties	2,452	(557)
Net cash provided by operating activities	16,133	13,903
Cash Flows from Investing Activities		
Acquisitions of oil and natural gas properties	(21,626)	(4,668)
Additions to oil and natural gas properties	(6,072)	(7,281)
Additions to other property and equipment	—	(133)
Proceeds from sales of oil and natural gas properties	1,163	—
Net cash used in investing activities	(26,535)	(12,082)
Cash Flows from Financing Activities		
Proceeds from line of credit	20,000	6,000
Payments on line of credit	(23,000)	(6,000)
Offering costs	—	(92)
Debt issuance costs	(651)	—

Proceeds from sale of Class B convertible preferred units, net of offering costs	14,847	—
Distributions to Class A convertible preferred units	(2,000)	(1,500)
Distributions to Class B convertible preferred units	(500)	—
Net cash provided by (used in) financing activities	8,696	(1,592)
Net (decrease) increase in cash and cash equivalents	(1,706)	229
Beginning cash and cash equivalents	1,832	2,359
Ending cash and cash equivalents	$126	$2,588

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 Partners Units	Limited Partners Amount	Total Equity
Balance, December 31, 2017	$ (572)	30,091	$ 82,260	$ 81,688
Equity-based compensation	—	345	670	670
Distributions to Class A convertible preferred units	—	—	(1,500)	(1,500)
Distributions to Class B convertible preferred units	—	—	(800)	(800)
Allocation of value to beneficial conversion feature of Class B convertible preferred units	—	—	686	686
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(876)	(876)
Accretion of beneficial conversion feature of Class B convertible preferred units	—	—	(127)	(127)
Net loss	(243)	—	(20,379)	(20,622)
Balance, September 30, 2018	$ (815)	30,436	$ 59,934	$ 59,119

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Operations

Nature of Operations

Mid-Con Energy Partners, LP ("we," "our," "us," the "Partnership," or the "Company") is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition 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 listed under the symbol "MCEP" on the NASDAQ. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company.

Basis of Presentation

Our unaudited condensed consolidated financial statements are prepared pursuant to the rules and regulations of the SEC. These financial statements have not been audited by our independent registered public accounting firm, except that the condensed consolidated balance sheet at December 31, 2017, is derived from the audited financial statements. Accordingly, certain information and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been condensed or omitted in this Form 10-Q. We believe that the presentations and disclosures made are adequate to make the information not misleading.

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

Non-cash Investing and Supplemental Cash Flow Information

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

	Nine Months Ended September 30,	
(in thousands)	2018	2017
Non-cash investing information		
Change in oil and natural gas properties - accrued capital expenditures	$315	$885
Change in oil and natural gas properties - accrued acquisitions	$1,897	$—
Supplemental cash flow information		
Cash paid for interest	$3,567	$3,566

Note 2. Acquisitions, Divestitures and Assets Held for Sale

Acquisitions

We adopted ASU No. 2017-01, “Business Combinations (Topic 805)” effective January 1, 2018. We now evaluate all acquisitions to determine whether they should be accounted for as a business combination or an asset acquisition. The assets acquired and liabilities assumed in the acquisitions were recorded in our unaudited condensed consolidated balance sheets at their estimated fair values as of the acquisition date using assumptions that represent Level 3 fair value measurement inputs. See Note 5 in this section for additional discussion of our fair value measurements. Results of operations attributable to the acquisition subsequent to the closing were included in our unaudited condensed consolidated statements of operations.

Pine Tree

In January 2018, we acquired multiple oil and natural gas properties located in Campbell and Converse Counties, Wyoming. The Pine Tree acquisition ("Pine Tree") was accounted for as a business combination. We acquired Pine Tree for cash consideration of $8.4 million, after final post-closing purchase price adjustments.

The recognized fair values of the Pine Tree assets acquired and liabilities assumed are as follows:

(in thousands)	
Fair value of net assets acquired	
Oil and natural gas properties	$9,232
Total assets acquired	9,232
Fair value of net liabilities assumed	
Asset retirement obligation	862
Net assets acquired	$8,370

The following table presents revenues and expenses of the acquired oil and natural gas properties included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Oil and natural gas sales	$ 325	$ —	$ 809	$ —
Expenses[1]	$ 235	$ —	$ 516	$ —

[1] Expenses include lease operating expenses ("LOE"), production taxes, accretion and depletion.

Wheatland

In June 2017, we acquired multiple oil and natural gas properties located in Oklahoma and Cleveland Counties, Oklahoma, for cash consideration of $4.0 million, after final post-closing purchase price adjustments. The Wheatland acquisition was accounted for as a business combination.

The recognized fair values of the assets acquired and liabilities assumed are as follows:

(in thousands)	
Fair value of net assets acquired	
Oil and natural gas properties	$4,305
Other property and equipment	132
Total assets acquired	4,437
Fair value of net liabilities assumed	
Asset retirement obligation	407
Net assets acquired	$4,030

The following table presents revenues and expenses of the acquired oil and natural gas properties included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
(in thousands)	2018	2017	2018	2017
Oil and natural gas sales	$ 681	$ 601	$ 2,179	$ 743
Expenses[(1)]	$ 485	$ 381	$ 1,608	$ 464

(1) Expenses include LOE, production taxes, accretion and depletion.

Divestitures

Effective at closing, the operations and cash flows of the following divested properties were eliminated from the ongoing operations of the Partnership, and the Partnership has no continuing involvement in these properties. The divestitures did not represent a strategic shift and did not have a major effect on the Partnership's operations or financial results.

Nolan County

In January 2018, we completed the sale of certain oil and natural gas proved properties in Nolan County, Texas, for $1.5 million, after final post-closing purchase price adjustments. These properties were deemed to meet held-for-sale accounting criteria as of December 31, 2017, and impairment of $0.3 million was recorded to reduce the carrying value of these assets to their estimated fair value of $1.5 million at December 31, 2017; therefore, no gain or loss was realized on the sale in 2018.

The following table presents revenues and expenses of the divested oil and natural gas properties that were included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Oil and natural gas sales	$ —	$ 123	$ —	$ 438
Expenses[1]	$ —	$ 74	$ —	$ 377

[1] Expenses include LOE, production taxes, accretion and depletion.

Southern Oklahoma

In December 2017, we sold the properties located in Southern Oklahoma for cash proceeds, net of expenses, of $21.7 million, prior to final post-closing purchase price adjustments, and we recognized a loss of $4.6 million.

The following table presents revenues and expenses of the oil and natural gas properties sold included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Oil and natural gas sales	$ —	$ 2,161	$ (5)	$ 7,124
Expenses[1]	$ —	$ 1,757	$ (17)	$ 5,813

[1] Expenses include LOE, production taxes, accretion and depletion.

Assets Held for Sale

Land in Southern Oklahoma met held-for-sale criteria as of September 30, 2018, and December 31, 2017. The carrying value of $0.4 million was presented in “Assets held for sale, net” in our unaudited condensed consolidated balance sheets.

Note 3. Equity Awards

We have a long-term incentive program (the “Long-Term Incentive Program”) for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating, LLC (“Mid-Con Energy Operating”) and ME3 Oilfield Service, LLC (“ME3 Oilfield Service”), who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, unrestricted units, restricted units, phantom units, distribution equivalent rights granted with phantom units and other types of awards. The Long-Term Incentive Program is administered by Charles R. Olmstead, Executive Chairman of the Board, and Jeffrey R. Olmstead, President and Chief Executive Officer, and approved by the Board of Directors of our general partner (the “Board”). 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.

The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at September 30, 2018:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,300,538)
Restricted units granted, net of forfeitures	(399,424)
Equity-settled phantom units granted, net of forfeitures	(932,669)
Awards available for future grant	881,369

We recognized \$0.3 million and \$0.6 million of total equity-based compensation expense for the three and nine months ended September 30, 2018, respectively, and we recognized \$0.1 million and \$0.4 million of total equity-based compensation expense for the three and nine months ended September 30, 2017, respectively. These costs are reported as a component of general and administrative expenses ("G&A") in our unaudited condensed consolidated statements of operations.

Unrestricted Unit Awards

During the nine months ended September 30, 2018, we granted 87,832 unrestricted units with an average grant date fair value of \$1.79 per unit. During the nine months ended September 30, 2017, we granted 25,400 unrestricted units with an average grant date fair value of \$2.65 per unit.

Restricted Unit Awards

All restricted units were vested as of September 30, 2018. A summary of our restricted unit awards for the nine months ended September 30, 2018, is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2017	6,362	\$ 5.42
Units granted	—	—
Units vested	(6,362)	5.42
Units forfeited	—	—
Outstanding at September 30, 2018	—	\$ —

Equity-Settled Phantom Unit Awards

Equity-settled phantom units vest over a period of two or three years and do not have any rights or privileges of a common unitholder, including right to distributions, until vesting and the resulting conversion into common units. During the nine months ended September 30, 2018, we granted 450,000 equity-settled phantom units with a two-year vesting period and 44,500 equity-settled phantom units with a three-year vesting period. During the nine months ended September 30, 2017, we granted 27,000 equity-settled phantom units with a two-year vesting period and 14,500 equity-settled phantom units with a three-year vesting period. As of September 30, 2018, there were $0.5 million of unrecognized compensation costs related to non-vested equity-settled phantom units. These costs are expected to be recognized over a weighted average period of twenty months.

A summary of our equity-settled phantom unit awards for the nine months ended September 30, 2018, is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2017	117,495	$ 1.45
Units granted	494,500	1.74
Units vested	(257,829)	1.63
Units forfeited	(3,000)	1.31
Outstanding at September 30, 2018	351,166	$ 1.73

Note 4. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices. 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 account for our commodity derivative contracts at fair value. See Note 5 in this section for a description of our fair value measurements.

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

At September 30, 2018, and at December 31, 2017, our commodity derivative contracts were in a net liability position with a fair value of $18.0 million and $4.9 million, respectively. All of our commodity derivative contracts are with major financial institutions that are also lenders under our revolving credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our commodity derivative contracts under lower commodity prices and we could incur a loss. As of September 30, 2018, all of our counterparties have performed pursuant to the terms of their commodity derivative contracts.

The following tables summarize the gross fair value by the appropriate balance sheet classification, even when the derivative financial instruments are subject to netting arrangements and qualify for net presentation, in our unaudited condensed consolidated balance sheets at September 30, 2018, and December 31, 2017:

(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets
September 30, 2018			
Liabilities			
Derivative financial instruments - current liability	(10,443)	(201)	(10,644)

Derivative deferred premium - current liability	(201)	201	—
Derivative financial instruments - long-term liability	(7,326)	—	(7,326)
Total	(17,970)	—	(17,970)
Net Liability	$ (17,970)	$ —	$ (17,970)

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(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets
December 31, 2017			
Assets			
Derivative financial instruments - current asset	$ 39	$ (39)	$ —
Total	39	(39)	—
Liabilities			
Derivative financial instruments - current liability	(3,890)	(362)	(4,252)
Derivative deferred premium - current liability	(401)	401	—
Derivative financial instruments - long-term liability	(666)	—	(666)
Total	(4,957)	39	(4,918)
Net Liability	$ (4,918)	$ —	$ (4,918)

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, 2018	2017	Nine Months Ended September 30, 2018	2017
Net settlements on matured derivatives[1]	$(2,483)	$323	$(5,988)	$524
Net settlements on early terminations of derivatives[1]	—	147	—	147
Net change in fair value of derivatives	(3,875)	(3,219)	(13,252)	2,245
Total (loss) gain on derivatives, net	$(6,358)	$(2,749)	$(19,240)	$2,916

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

At September 30, 2018, and December 31, 2017, our commodity derivative contracts had maturities at various dates through September 2020 and were comprised of commodity price swap, put and collar contracts. At September 30, 2018, 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 - 2018	$ 54.19	$ —	$ —	467	WTI
Puts - 2018	$ —	$ 45.00	$ —	326	WTI
Collars - 2018	$ —	$ 43.57	$ 53.13	1,141	WTI
Swaps - 2019	$ 56.14	$ —	$ —	1,779	WTI
Swaps - 2020	$ 54.81	$ —	$ —	1,199	WTI

At December 31, 2017, 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 - 2018	$ 51.33	$ —	$ —	444	WTI
Puts - 2018	$ —	$ 45.00	$ —	164	WTI
Collars - 2018	$ —	$ 44.38	$ 55.52	1,315	WTI
Swaps - 2019	$ 51.48	$ —	$ —	427	WTI

Note 5. Fair Value Disclosures

Fair Value of Financial Instruments

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

Fair Value Measurements

Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a three-tier fair value hierarchy that is intended to increase consistency and comparability in fair value measurements and related disclosures. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities recorded in the balance sheet are categorized based on the inputs to the valuation technique as follows:

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

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

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

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. We had no transfers in or out of Levels 1, 2 or 3 for the three and nine months ended September 30, 2018, and for the year ended December 31, 2017.

Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no material changes in valuation approach or related inputs for the three and nine months ended September 30, 2018, and for the year ended December 31, 2017.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

The following sets forth, by level within the hierarchy, the value of our assets and liabilities measured at fair value on a recurring basis as of September 30, 2018, and December 31, 2017:

(in thousands)	Level 1	Level 2	Level 3	Fair Value
September 30, 2018				
Derivative financial instruments - liability	$ —	$17,769	$—	$17,769
Derivative deferred premiums - liability	$ —	$—	$201	$201
December 31, 2017				
Derivative financial instruments - asset	$ —	$39	$—	$39
Derivative financial instruments - liability	$ —	$4,556	$—	$4,556
Derivative deferred premiums - liability	$ —	$—	$401	$401

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

(in thousands)	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Balance of Level 3 at beginning of period	$ (401)	$ (5,449)
Derivative deferred premiums - settlements	200	5,048
Balance of Level 3 at end of period	$ (201)	$ (401)

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

Asset Retirement Obligations

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

Acquisitions

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

Reserves

We calculate the estimated fair values of reserves and properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of reserves, future operating and developmental costs, future commodity prices, a market-based weighted average cost of capital rate and the rate at which future cash flows are discounted to estimate present value. We discount future values by a per annum rate of 10% 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 begin with Level 1 NYMEX-WTI forward curve pricing, less Level 3 assumptions that include location, pricing adjustments and quality differentials.

Impairment

The need to test oil and natural gas assets for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. If the carrying value of the long-lived assets exceeds the estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. For the nine months ended September 30, 2018, we recorded non-cash impairment of

$9.7 million. We recorded non-cash impairment of $4.9 million and $22.5 million for the three and nine months ended September 30, 2017.

Note 6. Asset Retirement Obligations

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

As of September 30, 2018, and December 31, 2017, 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:

(in thousands)	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Asset retirement obligations - beginning of period	$ 10,326	$ 11,331
Liabilities incurred for new wells and interest	28,639	759
Liabilities settled upon plugging and abandoning wells	(114)	(57)
Liabilities removed upon sale of wells	(399)	(2,152)
Revision of estimates	(8)	(75)
Accretion expense	748	520
Asset retirement obligations - end of period	$ 39,192	$ 10,326

Note 7. Debt

We had outstanding borrowings under our revolving credit facility of $96.0 million and $99.0 million at September 30, 2018, and December 31, 2017, respectively. Our current revolving credit facility matures in November 2020.

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 variables. The borrowing base is subject to scheduled redeterminations in the spring and fall of each year with an additional redetermination, either at our request or at the request of the lenders, during the period between each scheduled borrowing base redetermination. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election, the greater of the prime rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50% and the one month adjusted London Interbank Offered Rate ("LIBOR") plus 1.0%, all of which are subject to a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or the applicable LIBOR plus a margin that varies from 2.75% to 3.75% per annum according to the borrowing base usage. For the three months ended September 30, 2018, the average effective rate was 5.60%. Any unused portion of the borrowing base will be subject to a commitment fee of 0.50% per annum. Letters of credit are subject to a letter of credit fee that varies from 2.75% to 3.75% according to usage.

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

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

During the quarter ended September 30, 2017, we were not in compliance with our leverage ratio calculation. On November 10, 2017, the Partnership received a waiver from the Administrative Agent and the Lenders of our revolving credit facility waiving the noncompliance through December 15, 2017. On December 22, 2017, Amendment 11 to the credit agreement was finalized. The amendment extended the waiver of the leverage ratio default until January 31, 2018. This amendment decreased the Partnership's borrowing base to $115.0 million effective December 22, 2017, and required the facility usage not exceed $100.0 million. The amendment also required that the cash proceeds received from the Southern Oklahoma divestiture on December 22, 2017, and the Nolan County divestiture on January 9, 2018, be applied to the borrowings outstanding. See Note 2 in this section for more information regarding these divestitures.

On January 31, 2018, Amendment 12 to the credit agreement was executed, extending the maturity of our credit facility from November 2018 until November 2020 and increasing the borrowing base of the Partnership's revolving credit facility to $125.0 million. The lenders also waived any default or event of default that occurred as a result of the Partnership's failure to maintain the required leverage ratios for the quarter ended September 30, 2017. The amendment also required the Partnership to have a minimum liquidity of 20% to make cash distributions to the Preferred Unitholders. As of September 30, 2018, we were in compliance with our financial covenants.

During the spring 2018 semi-annual borrowing base redetermination of our revolving credit facility completed in June 2018, the lender group reaffirmed the Partnership's $125.0 million conforming borrowing base. There were no changes to the terms or conditions of the credit agreement.

We anticipate our fall 2018 redetermination to begin and be completed during the fourth quarter of 2018.

Note 8. Commitments and Contingencies

Leases

We lease office space in Tulsa, Oklahoma, Abilene, Texas, and Gillette, Wyoming. Total lease expenses were $0.1 million and $0.2 million for both the three and nine months ended September 30, 2018, and 2017. These expenses are included in G&A in our unaudited condensed consolidated statements of operations.

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

(in thousands)	
Remaining 2018	$129
2019	484
2020	469
2021	471

Total	$1,553

Services Agreement

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

Employment Agreements

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

Legal

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

Note 9. Equity

Common Units

At September 30, 2018, and December 31, 2017, the Partnership’s equity consisted of 30,436,124 and 30,090,463 common units, respectively, representing a 98.8% limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution Agreement to sell, from time to time through or to the Managers (as defined in the agreement), up to \$50.0 million in common units representing limited partner interests. In connection with the Preferred Units agreements described below, the Partnership suspended sales of common units pursuant to the Equity Distribution Agreement effective as of the closing date until the fifth anniversary of the closing date of the Class A Preferred Units purchase agreement, without the consent of a majority of the holders of the outstanding Preferred Units.

Our Partnership Agreement requires us to distribute all of our available cash on a quarterly basis. Our available cash is our cash on hand at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs, including cash from working capital borrowings. As of September 30, 2018, cash distributions to our common units continued to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions. Management and the Board will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of common unit cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders. There is no assurance as to future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors.

Preferred Units

The Partnership has issued two classes of Preferred Units. Per accounting guidance, we were required to allocate a portion of the proceeds from Preferred Units to a beneficial conversion feature based on the intrinsic value of the beneficial conversion feature. The intrinsic value is calculated at the commitment date based on the difference between the fair value of the common units at the issuance date (number of common units issuable at conversion multiplied by the per-share value of our common units at the issuance date) and the proceeds attributed to the class of Preferred Units. The beneficial conversion feature is accreted using the effective yield method over the period from the closing date to the effective date of the holder’s conversion right.

The holders of our Preferred Units are entitled to certain rights that are senior to the rights of holders of common units, such as rights to distributions and rights upon liquidation of the Partnership. We pay holders of Preferred Units a cumulative, quarterly cash distribution on Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership’s existing secured indebtedness prevents the payment of a cash distribution to all holders of the Preferred Units, in kind (additional Class A or Class B Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end, or as otherwise permitted to accumulate pursuant to the Partnership Agreement.

Prior to August 11, 2021, each holder of Preferred Units has the right, subject to certain conditions, to convert all or a portion of their Preferred Units into common units representing limited partner interests in the Partnership on a one-for-one basis, subject to adjustment for splits, subdivisions, combinations and reclassifications of the common units. Upon conversion of the Preferred Units, the Partnership will pay any distributions (to the extent accrued and unpaid as of the then most recent Preferred Units distribution date) on the converted units in cash.

Class A Preferred Units

On August 11, 2016, we completed a private placement of 11,627,906 Class A Preferred Units for an aggregate offering price of $25.0 million. The Class A Preferred Units were issued at a price of $2.15 per Class A Preferred Unit. Proceeds from this issuance were used to fund the Permian Bolt-On acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of $24.6 million in connection with the issuance of these Class A Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Class A Preferred Units ($18.6 million) and the beneficial conversion feature ($6.0 million). Accretion of the beneficial conversion feature was $0.3 million and $0.9 million for the three and nine months ended September 30, 2018. Accretion of the beneficial conversion feature was $0.3 million and $0.8 million for the three and nine months ended September 30, 2017. The registration statement registering resales of common units issued or to be issued upon conversion of the Class A Preferred Units was declared effective by the SEC on June 14, 2017.

At September 30, 2018, the Partnership had accrued $0.5 million for the third quarter 2018 distribution that will be paid in cash in November 2018. The following table summarizes cash distributions paid on our Class A Preferred Units during the nine months ended September 30, 2018:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2018	July 1, 2017 - December 31, 2017	$ 0.0860	$ 1,000
May 15, 2018	January 1, 2018 - March 31, 2018	$ 0.0430	$ 500
August 22, 2018	April 1, 2018 - June 30, 2018	$ 0.0430	$ 500

The following table summarizes cash distributions paid on our Class A Preferred Units during the nine months ended September 30, 2017:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2017	October 1, 2016 - December 31, 2016	$ 0.0430	$ 500
May 15, 2017	January 1, 2017 - March 31, 2017	$ 0.0430	$ 500
August 14, 2017	April 1, 2017 - June 30, 2017	$ 0.0430	$ 500

Class B Preferred Units

On January 31, 2018, we completed a private placement of 9,803,921 Class B Preferred Units for an aggregate offering price of $15.0 million. The Class B Preferred Units were issued at a price of $1.53 per Class B Preferred Unit. Proceeds from this issuance were used to fund the acquisition of certain oil and natural gas properties located in Campbell and Converse Counties, Wyoming, and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of $14.9 million in connection with the issuance of these Class B Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Class B Preferred Units ($14.2 million) and the beneficial conversion feature ($0.7 million). Accretion of the beneficial conversion feature was $0.1 million for the nine months ended September 30, 2018. The registration statement registering resales of common units issued or to be issued upon conversion of the Class B Preferred Units was declared effective by the SEC on May 25, 2018.

At September 30, 2018, the Partnership had accrued $0.3 million for the third quarter 2018 distribution that will be paid in cash in November 2018. The following table summarizes cash distributions paid on our Class B Preferred Units during the nine months ended September 30, 2018:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
May 15, 2018	February 1, 2018 - March 31, 2018	$ 0.0204	$ 200
August 22, 2018	April 1, 2018 - June 30, 2018	$ 0.0306	$ 300

Allocation of Net Income or Loss

Net income or loss is allocated to our general partner in proportion to its pro rata ownership during the period. The remaining net income or loss is allocated to the limited partner unitholders net of Preferred Unit distributions, including accretion of the Preferred Unit beneficial conversion feature. In the event of net income, diluted net income per partner unit reflects the potential dilution of non-vested restricted stock awards and the conversion of Preferred Units.

Note 10. Related Party Transactions

Agreements with Affiliates

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

Services Agreement

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

Operating Agreements

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

Oilfield Services

We are party to operating agreements, pursuant to which our affiliate, Mid-Con Energy Operating, bills us for oilfield services performed by our affiliates, ME3 Oilfield Service, LLC and ME2 Well Services, LLC. These amounts are either included in LOE in our unaudited condensed consolidated statements of operations or are capitalized as part of oil and natural gas properties in our unaudited condensed consolidated balance sheets.

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

	Three Months Ended September 30,	Nine Months Ended September 30,

(in thousands)	2018	2017	2018	2017
Services agreement	$617	$610	$1,746	$1,903
Operating agreements	2,145	1,678	4,936	4,694
Oilfield services	928	809	2,956	2,476
	$3,690	$3,097	$9,638	$9,073

At September 30, 2018, we had a net payable to our affiliate, Mid-Con Energy Operating, of $4.5 million, comprised of a joint interest billing payable of $4.3 million and a payable for operating services of $0.2 million. At December 31, 2017, we had a net payable to our affiliate, Mid-Con Energy Operating, of $1.6 million, comprised of a joint interest billing payable of $1.4 million and a payable for operating services of $0.2 million. These amounts were included in accounts payable-related parties in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

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. We are currently in the process of identifying all contracts that are leases or contain leases. We plan to adopt this standard on January 1, 2019, and believe the primary impact of adoption will be the recognition of assets and liabilities on our balance sheet for current operating leases.

Note 12. Revenue Recognition

We adopted ASC 606 effective January 1, 2018, using the modified retrospective approach. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Under ASC 605, we followed the sales method of accounting for oil and natural gas sales revenues in which revenues were recognized on our share of actual proceeds from oil and natural gas sold to purchasers. Revenue recognition required for our oil and natural gas sales contracts by ASC 606 does not differ from revenue recognition required under ASC 605 to account for such contracts. Therefore, we concluded that there was no change in our revenue recognition under ASC 606 and the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018, did not result in an adjustment to retained earnings.

Revenue from Contracts with Customers

Under our oil and natural gas sales contracts, enforceable rights and obligations arise at the time production occurs on dedicated leases as the Partnership promises to deliver goods in the form of oil or natural gas production on contractually-specified leases to the purchasers. Sales of oil and natural gas are recognized at the point that control of the product is transferred to the customer; title and risk of loss to the product generally transfers at the delivery point specified in the contract. The Partnership commits and dedicates for sale all of the crude oil or natural gas production from contractually agreed-upon leases to the purchaser. Our oil contract pricing provisions are tied to a market index, with certain marketing adjustments, including location and quality differentials as well as certain embedded marketing fees. Our natural gas sales revenues are a percentage of the proceeds received by the purchaser for selling the volume of gas produced by the Partnership on a monthly basis. The purchaser sells the volume of natural gas at index rates per Mcf. Payment is typically received 30 to 60 days after the date production is delivered.

Transaction Price Allocated to Remaining Performance Obligations

Our product sales are generally short-term in nature, with a contract term of one year or less. For those contracts, we have utilized the practical expedient in ASC 606-10-50-14, exempting the Partnership from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

We have utilized the practical expedient in ASC 606-10-50-14(a), which states the Partnership is not required to disclose the transaction price allocated to remaining performance obligations for specific situations in which the Partnership does not need to estimate variable consideration to recognize revenue. For our crude oil sales and natural gas sales contracts, the variable consideration related to variable production is not estimated because the uncertainty related to the consideration is resolved as the barrel of oil ("Bbl") and Mcf of natural gas are transferred to the customer each day.

Contract Balances

Our product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Note 13. Subsequent Events

Distributions

On October 24, 2018, the Partnership announced that the Board declared Preferred Unit distributions for the third quarter of 2018, according to terms outlined in the Partnership Agreement. Distributions will be paid on November 14, 2018, to holders of record as of the close of business on November 7, 2018. The Class A Preferred Unit cash distributions will be $0.043 per Class A Preferred Unit, or $0.5 million in aggregate. Additionally, the Class B Preferred Unit cash distributions will be $0.0306 per Class B Preferred Unit, or $0.3 million in aggregate.

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

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

Overview

Mid-Con Energy Partners, LP is a publicly held limited partnership formed in July 2011 that engages in the ownership, acquisition and development of producing oil and natural gas properties in North America, with a focus on EOR. Our properties are located in Oklahoma, Texas and Wyoming. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Executive Summary

Highlights and Recent Developments

During the three months ended September 30, 2018, we generated solid results by continuing to decrease total leverage, growing production and operating cash flow and building our inventory of future projects through acquisitions of optimization and growth assets. The quarter included the following achievements:

- During the third quarter, we closed on acquisitions in Oklahoma and Wyoming for a total purchase price of $14.7 million, subject to customary post-closing adjustments. These acquisitions included optimization opportunities in Oklahoma and Wyoming, as well as a high growth asset in Wyoming.
- These acquisitions, combined with approximately $2.3 million in capital expenditure spending, resulted in net production averaging 3,609 Boe/d during the third quarter 2018. This was an increase of 23.0% from second quarter 2018.
- Net loss and operating cash flows continued to improve primarily due to an increase in realized oil pricing, and an increase in total production from our acquisitions and capital expenditures.
- Total outstanding debt at November 5, 2018, increased by $8.0 million since the second quarter 2018 due to our recent acquisitions and capital expenditures.
- Total liquidity at November 5, 2018, was $29.5 million, consisting of $0.5 million in available cash and $29.0 million in available borrowings ($125.0 million borrowing base less $95.0 million outstanding borrowings and $1.0 million outstanding standby letter of credit).
- Total leverage, as calculated per our credit agreement, continues to decrease, and was below 3.0X for the period ending September 30, 2018, as growing cash flows more than offset the increase in outstanding debt during the quarter.
- On August 22, 2018, we paid cash distributions on Class A Preferred Units of $0.5 million and on Class B Preferred Units of $0.3 million for the second quarter of 2018.

Operating Performance

- The Partnership continued to see positive results from the properties acquired in the Wyoming Powder River Basin during the first quarter of 2018. At our House Creek Sussex Unit, we have continued to return wells to active status with a positive impact on unit production. The Partnership has returned 45 wells to active status since acquisition. At Pine Tree, the working interest owners have given approval to commence secondary operations, and the Partnership received regulatory approval to convert six wells to injection, and first injection is planned to occur in the remainder of 2018. Four wells were also returned to production at Pine Tree in the third quarter.

- In the third quarter, the Partnership drilled three producing wells, performed two recompletions, six capital workovers and re-entered one plugged well to re-establish production.
- Development of waterfloods in our Oklahoma and Texas properties continue to show positive response and further development is planned for the remainder of 2018.
- The Partnership is currently evaluating recent acquisitions in Oklahoma and Wyoming for operational efficiencies, well reactivations and stimulations and opportunities for reductions in lease operating expenses.

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 and natural gas may fluctuate widely. Sustained periods of low prices for oil and natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. Our average sales price per Bbl, excluding commodity derivative contracts, was $61.70 and $46.28 for the nine months ended September 30, 2018, and 2017, respectively.

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices. 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. We have entered oil commodity derivative contracts covering a portion of our anticipated oil production through September 2020.

Our business faces the challenge of natural production declines. As initial reservoir pressures are depleted, production from a given well or formation decreases. Although our waterflood operations tend to restore reservoir pressure and production, once a waterflood is fully effected, production, once again, begins to decline. Our future growth will depend on our ability to continue to add reserves in excess of our production. Our focus on adding reserves is primarily through improving the economics of producing oil from our existing fields and, secondarily, through acquisitions of additional proved reserves. Our ability to add reserves through development 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 may distribute to our unitholders in the future depends principally on the cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other factors:

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

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

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

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess the cash flow generated by our assets, without regard to financing methods, capital structure or historical cost basis and our ability to incur and service debt and fund capital expenditures. In addition, management uses Adjusted EBITDA to evaluate actual potential cash flow available to reduce debt, develop existing reserves or acquire additional properties and pay distributions to our unitholders. Adjusted EBITDA is a non-GAAP measure and should not be considered an alternative to net income (loss), net cash provided by operating activities or any other performance or liquidity measure determined in accordance with GAAP. Our calculations of Adjusted EBITDA are not necessarily comparable to EBITDA or Adjusted EBITDA as calculated by other companies.

Results of Operations

The tables presented in this section summarize certain of the results of operations and period-to-period comparisons for the three and nine months ended September 30, 2018, and 2017. Because of normal production declines, changes in drilling activities, fluctuations in commodity prices and the effects of acquisitions and divestitures, the historical data presented below should not be interpreted as being indicative of future results.

Production and Unit Costs per Boe. The table below provides production volume data and average unit costs per Boe:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2018	2017	Change		2018	2017	Change	
Production Volumes								
Oil (MBbls)	309	304	5	2%	798	915	(117)	(13%)
Natural gas (MMcf)	139	105	34	32%	317	339	(22)	(6%)
Total (MBoe)	332	322	10	3%	851	972	(121)	(12%)
Average daily net production (Boe/d)	3,609	3,500	109	3%	3,117	3,560	(443)	(12%)
Average sales price								
Oil (per Bbl)								
Sales price	$60.73	$45.17	$15.56	34%	$61.70	$46.28	$15.42	33%
Effect of net settlements on matured derivative instruments	$(8.69)	$(3.33)	$(5.36)	161%	$(7.75)	$(3.74)	$(4.01)	107%
Realized oil price after derivatives	$52.04	$41.84	$10.20	24%	$53.95	$42.54	$11.41	27%
Natural gas (per Mcf)	$2.73	$2.22	$0.51	23%	$2.56	$2.71	$(0.15)	(6%)
Average unit costs per Boe								
Lease operating expenses	$20.04	$19.01	$1.03	5%	$19.63	$17.18	$2.45	14%
Oil and natural gas production taxes	$3.48	$2.66	$0.82	31%	$3.52	$2.43	$1.09	45%
Depreciation, depletion and amortization	$14.49	$13.51	$0.98	7%	$13.69	$14.25	$(0.56)	(4%)
General and administrative expenses	$4.50	$3.69	$0.81	22%	$5.58	$4.61	$0.97	21%

Oil and natural gas sales. The following table provides oil and natural gas sales data for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended September 30,		Change		Nine Months Ended September 30,		Change	
(in thousands)	2018	2017	$	%	2018	2017	$	%
Oil sales	$18,765	$13,731	$5,034	37%	$49,240	$42,343	$6,897	16%
Natural gas sales	380	233	147	63%	812	917	(105)	(11%)
Total oil and natural gas sales	$19,145	$13,964	$5,181	37%	$50,052	$43,260	$6,792	16%

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The following table details the change in revenues due to price and volume variances:

	Three Months Ended September 30, 2018 and 2017			Nine Months Ended September 30, 2018 and 2017		
(in thousands, except prices)	Change in prices	Production Volumes	Total Net Dollar Effect of Change	Change in prices	Production Volumes	Total Net Dollar Effect of Change
Effects of changes in sales price						
Oil (Bbls)	$15.56	309	$4,808	$15.42	798	$12,309
Natural gas (Mcf)	$0.51	139	71	(0.15)	317	(46)
Total revenues due to change in price			$4,879			$12,263
	Change in Production Volumes	Prior Period Average Prices	Total Net Dollar Effect of Change	Change in Production Volumes	Prior Period Average Prices	Total Net Dollar Effect of Change
Effects of changes in production volumes						
Oil (Bbls)	5	$ 45.17	$226	(117)	$ 46.28	$(5,413)
Natural gas (Mcf)	34	$ 2.22	76	(22)	2.71	(58)
Total revenues due to change in production volumes			302			(5,471)
Total change in revenues			$5,181			$6,792

The change in oil and natural gas sales for the three and nine months ended September 30, 2018, compared to the three and nine months ended September 30, 2017, was primarily due to:

- increased oil sales prices; and
- incremental production from the Oklahoma and Wyoming acquisition properties; offset by the
- divestiture of our Southern Oklahoma properties.

(Loss) gain on derivatives, net. The table below summarizes the non-cash and cash components of our commodity derivative contracts as well as the change for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended September 30,		Change		Nine Months Ended September 30,		Change	
(in thousands)	2018	2017	$	%	2018	2017	$	%
Cash settlements on matured derivatives[(1)]	$(2,483)	$323	$(2,806)	(869%)	$(5,988)	$524	$(6,512)	(1243%)
Net cash settlements on early terminations of derivatives[(1)]	—	147	(147)	(100%)	—	147	(147)	(100%)

Non-cash change in fair value of derivatives	(3,875)	(3,219)	(656)	20%	(13,252)	2,245	(15,497)	(690%)
Total (loss) gain on derivatives, net	$(6,358)	$(2,749)	$(3,609)	131%	$(19,240)	$2,916	$(22,156)	(760%)

(1) The settlement amount does not include premiums paid attributable to contracts that matured or terminated early during the respective period.

Production expenses. The following table summarizes the change in oil and natural gas production expense for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended				Nine Months Ended			
	September 30,		Change		September 30,		Change	
(in thousands)	2018	2017	$	%	2018	2017	$	%
Lease operating expenses	$6,654	$6,122	$532	9%	$16,706	$16,695	$11	0%
Oil and natural gas production taxes	1,157	857	300	35%	2,992	2,366	626	26%
Total oil and natural gas production expenses	$7,811	$6,979	$832	12%	$19,698	$19,061	$637	3%
Effective production tax rate	6.1%	6.1%	0.0%	0%	6.0%	5.5%	0.5%	9%

The change in production expenses for the three and nine months ended September 30, 2018, compared to the three and nine months ended September 30, 2017, was primarily due to:

- incremental costs associated with properties acquired in Oklahoma and Wyoming;
- increased workovers at properties acquired in Oklahoma and Wyoming and on certain Texas properties;
- decreased spending on Texas properties;
- increased production taxes due to higher sales prices;
- divestiture of our Southern Oklahoma properties; and
- discontinuation of the EOR tax credit at one of our Oklahoma units effective July 1, 2017.

The following table summarizes production expenses per Boe data for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended				Nine Months Ended			
	September 30,		Change		September 30,		Change	
(per Boe)	2018	2017	$	%	2018	2017	$	%
Lease operating expenses	$20.04	$19.01	$1.03	5%	$19.63	$17.18	$2.45	14%
Oil and natural gas production taxes	3.48	2.66	0.82	31%	3.52	2.43	1.09	45%
Total oil and natural gas production expenses per Boe	$23.52	$21.67	$1.85	9%	$23.15	$19.61	$3.54	18%

The change in production expenses per Boe for the three months ended September 30, 2018, compared to the three months ended September 30, 2017, was primarily due to the changes noted above. The change in production expenses per Boe for the nine months ended September 30, 2018, compared to the nine months ended September 30, 2017, was primarily due to a decrease in production volumes.

Depreciation, Depletion, Amortization and Impairment Expenses. The following table provides our non-cash depreciation, depletion and amortization ("DD&A") and impairment expense for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended				Nine Months Ended			
	September 30,		Change		September 30,		Change	
(in thousands)	2018	2017	$	%	2018	2017	$	%
Depreciation, depletion and amortization	$4,812	$4,350	$462	11%	$11,646	$13,850	$(2,204)	(16%)
Impairment	—	4,850	(4,850)	(100%)	9,710	22,522	(12,812)	(57%)
Total DD&A and impairment	$4,812	$9,200	$(4,388)	(48%)	$21,356	$36,372	$(15,016)	(41%)

The change in DD&A for the three months ended September 30, 2018, compared to the three months ended September 30, 2017, was primarily due to the net impact of the Oklahoma and Wyoming acquisitions and the Southern Oklahoma divestiture.

The change in DD&A for the nine months ended September 30, 2018, compared to the nine months ended September 30, 2017, was primarily due to:

- decreased depletion rates due to increased reserves;

- reduced asset carrying values due to impairment;
- decreased production volumes; and
- the net impact of the Oklahoma and Wyoming acquisitions and the Southern Oklahoma divestiture.

The decrease in impairment for the three and nine months ended September 30, 2018, compared to the three and nine months ended September 30, 2017,was primarily due to higher strip pricing and lower net book values on previously impaired properties.

General and Administrative Expenses. The following table provides components of our G&A for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended				Nine Months Ended			
	September 30,		Change		September 30,		Change	
(in thousands, except for per Boe)	2018	2017	$	%	2018	2017	$	%
General and administrative expenses	$1,191	$1,115	$76	7%	$4,076	$4,076	$—	0%
Non-cash compensation	303	73	230	315%	670	409	261	64%
Total general and administrative expenses	$1,494	$1,188	$306	26%	$4,746	$4,485	$261	6%
General and administrative expenses (per Boe)	$4.50	$3.69	0.81	22%	$5.58	$4.61	0.97	21%

The change in both G&A and G&A per Boe for the three and nine months ended September 30, 2018, compared to the three and nine months ended September 30, 2017, was primarily due to increased non-cash compensation.

Interest Expense. Interest expense is impacted by our borrowings outstanding, interest rates, commitment fees and related debt placement fees which are amortized over the life of the credit agreement. The following table sets forth interest expense for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended				Nine Months Ended			
	September 30,		Change		September 30,		Change	
(in thousands)	2018	2017	$	%	2018	2017	$	%
Interest expense	$1,620	$1,626	$(6)	(0%)	$4,369	$4,615	$(246)	(5%)
Average effective interest rate	5.60%	4.02%	1.58%	39%	5.26%	3.80%	1.46%	38%

The change in interest expense for the three and nine months ended September 30, 2018, compared to the three and nine months ended September 30, 2017, was primarily due to:

- lower outstanding borrowings; offset by a
- higher effective interest rate caused by an increase in the underlying market rate and an increase in margins per Amendment 12 to our revolving credit facility.

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 borrow and our ability to raise equity or debt capital. 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 (including regional price differentials), operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. Historically, our primary use of cash has been for debt reduction, capital spending, including acquisitions and distributions.

Since November 2014, oil prices have been extremely volatile, impacting the way we conduct business. In response, we have implemented a number of adjustments to strengthen our financial position. We have continued to hedge a portion of our production to limit downside and volatility in the prevailing commodity price environment. We have aggressively pursued cost reductions to improve profitability and maximize cash flows. Our primary cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of LOE and G&A. Additionally, in the third quarter 2015, we indefinitely suspended our quarterly cash distributions on common units.

Our liquidity position at November 5, 2018, consisted of approximately $0.5 million of available cash and $29.0 million of available borrowings ($125.0 million borrowing base less $95.0 million outstanding borrowings and $1.0 million outstanding standby letter of credit). Our borrowing base is redetermined in the spring and fall of each year.

Revolving Credit Facility

During the spring 2018 semi-annual redetermination of the revolving credit facility completed in June 2018, the lender group reaffirmed the existing conforming borrowing base of $125.0 million. There were no changes to the terms or conditions of the credit agreement. At November 5, 2018, the outstanding borrowings of our revolving credit facility were $95.0 million.

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

Capital Requirements

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

We currently expect capital spending for the remainder of 2018 for the development, growth and maintenance of our oil and natural gas properties to be $2.6 million. We will adjust our capital program in response to business conditions and operating results along with our evaluation of additional development opportunities that are identified throughout the year.

Commodity Derivative Contracts

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices. 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 September 30, 2018, we had commodity derivative contracts covering approximately 63%, 58% and 52%, respectively, of our estimated 2018, 2019 and 2020 average daily production (estimate calculated based on the mid-point of our full year 2018 Boe production guidance as released on November 5, 2018, and multiplied by a 93% oil weighting based on third quarter 2018 reported production volumes). See Note 4 to the unaudited condensed consolidated financial statements for additional information regarding our commodity derivative contracts.

Preferred Units

As of September 30, 2018, we have issued $25.0 million of Class A Preferred Units and $15.0 million of Class B Preferred Units through private placements in August 2016 and January 2018, respectively. Both classes of Preferred Units receive a cumulative, quarterly cash distribution on Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership’s existing secured indebtedness prevents the payment of a cash distribution to all holders of the Preferred Units, in kind (additional Class A or Class B Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end, or as otherwise permitted to accumulate pursuant to the Partnership Agreements. See Note 9 to the unaudited condensed consolidated financial statements for additional information regarding Preferred Units.

Sources and Uses of Cash

The following table summarizes the net increase (decrease) in cash for the nine months ended September 30, 2018, and 2017:

	Nine Months Ended September 30,			
(in thousands)	2018	2017	Change	% Change
Net cash provided by operating activities	$16,133	$13,903	$2,230	16%
Net cash used in investing activities	(26,535)	(12,082)	(14,453)	120%
Net cash provided by (used in) financing activities	8,696	(1,592)	10,288	646%
Net (decrease) increase in cash and cash equivalents	$(1,706)	$229	$(1,935)	(845%)

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Operating Activities. The change in operating cash flows for the periods compared was primarily attributable to:

- increased oil sales of $6.9 million due to pricing; and
- lower debt issuance costs of $0.5 million; offset by
- higher production taxes of $0.6 million;
- increased net settlements paid on derivatives of $1.9 million; and
- decreased working capital of $1.7 million.

Investing Activities. The change in net cash used in investing activities was primarily attributable to:

- an increase in acquisitions of oil and natural gas properties of $16.9 million; and
- a decrease in drilling and completion activities of $1.2 million; less
- net proceeds of $1.2 million from the sales of oil and natural gas properties.

Financing Activities. The change in net cash provided by financing activities was primarily attributable to:

- net proceeds of $14.9 million from the issuance of Class B Preferred Units;
- an increase of net payments on the revolving credit facility of $3.0 million;
- an increase in distributions of $1.0 million to Preferred Unitholders; and
- payments of $0.7 million for debt issuance costs.

Off–Balance Sheet Arrangements

As of September 30, 2018, we had no off-balance sheet arrangements.

Recently Issued Accounting Pronouncements

See Note 11 to the unaudited condensed consolidated financial statements for additional information regarding recently issued accounting pronouncements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As a smaller reporting company, we are not required to provide the information otherwise required by this item.

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, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal 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 principal executive officer and principal 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, 2018, 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, 2017.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

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

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

+Filed herewith

SIGNATURES

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 5, 2018	By:	/s/ Jeffrey R. Olmstead Jeffrey R. Olmstead Chief Executive Officer
November 5, 2018	By:	/s/ Philip R. Houchin Philip R. Houchin Chief Financial Officer