MID-CON ENERGY PARTNERS, LP

FORM 10-K
(Annual Report)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10–K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2015

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 No.)**

2501 North Harwood Street, Suite 2410
Dallas, Texas 75201
(Address of principal executive offices and zip code)

(972) 479-5980
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Common Units Representing Limited Partner Interests	**NASDAQ Global Select Market**
(Title of each class)	**(Name of each exchange on which registered)**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well–known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☒

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ☒ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S–K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III or any amendment to the Form 10–K. ☒

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

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b–2 of the Exchange Act). YES ☐ NO ☒

The aggregate market value of the common units held by non-affiliates of the registrant was approximately $107.8 million on June 30, 2015, based on $5.00 per unit, the last reported sales price of the units on The NASDAQ Global Select Market on such date.

Documents incorporated by Reference: None.

As of February 29, 2016 the registrant had 29,786,710 common units and 360,000 general partner units outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following includes a description of the meanings of some of the oil and natural gas industry terms used throughout this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been excerpted from the applicable definitions contained in Rule 4-10(a) of Regulation S-X.

Basin: A large depression on the earth's surface in which sediments accumulate.

Bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbl/d : One Bbl per day.

Behind Pipe: Reserves associated with recompletion projects which have not been previously produced.

Boe: Barrel of Oil Equivalent, equals six Mcf of natural gas or one Bbl of oil based on a rough energy equivalency. This is a physical correlation of heat content and does not reflect a value or price relationship between the commodities.

Boe/d: One Boe per day.

Btu: One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Conventional Hydraulic Fracturing: Hydraulic fracturing is used to stimulate production from new and existing oil and natural gas wells. Large volumes of fracturing fluids, or "fracing fluids," are pumped deep into the well at high pressures sufficient to cause the reservoir rock to break or fracture. Almost all frac fluid mixtures are comprised of more than 95 percent water. As the pressure builds within the well, rock beds begin to crack. More fluid is added while the pressure is increased until the rock beds finally fracture, creating channels for trapped oil and natural gas to flow into the well and up to the surface. The fractures are kept open with proppants made of small granular solids (generally sand) to ensure the continued flow of fluids. By creating or even restoring fractures, the surface area of a formation exposed to the borehole increases and the fracture provides a conductive path that connects the reservoir to the well. These new paths increase the rate that fluids can be produced from the reservoir formations, in some cases by many hundreds of percent.

Developed Acreage: Acres spaced or assigned to productive wells or wells capable of production.

Development Well: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry Hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

EOR: Enhanced Oil Recovery.

EPA: United States Environmental Protection Agency.

Exploitation: Drilling or other projects that may target proven or unproven reserves (such as probable or possible reserves), but that generally have a lower risk than that associated with exploration projects.

Exploratory Well: A well drilled to find and produce oil and natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field: An area comprised of multiple leases in close proximity to one another that typically produce from the same reservoirs and may or may not be produced under waterflood.

Gross wells: The number of wells in which a working interest is owned.

Injection Well: A well employed for the introduction into an underground stratum of water, gas or other fluid under pressure.

MBbls : One thousand Bbls.

MBoe: One thousand Boe.

MBtu: One thousand Btu.

MBoe/d: One thousand Boe per day.

Mcf: One thousand cubic feet of natural gas.

Mcf/d : One thousand cubic feet of natural gas per day.

MMBoe: One million Boe.

MMBtu: One million Btu.

MMcf : One million cubic feet of natural gas.

NGLs: Natural gas liquids.

Net Production: Production that is owned by us, less royalties and production due others.

Net Revenue Interest: A working interest owner's gross working interest in production, less the royalty, overriding royalty, production payment and net profits interests.

Net Well: The total of fractional working interests owned in a gross well.

NYMEX: New York Mercantile Exchange.

Oil: Oil, condensate and natural gas liquids.

Productive Well: A well that is producing or that is mechanically capable of production.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves: Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves: Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Realized Price: The cash market price, less all expected quality, transportation and demand adjustments.

Recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed. Reserves associated with recompletion are also referred to as "Behind Pipe."

Reserve: That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

Spot Price : The cash market price without reduction for expected quality, transportation and demand adjustments.

Standardized Measure: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC"), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Because we are a limited partnership, we are generally not subject to federal or state income taxes and thus make no provision for federal or state income taxes in the calculation of our standardized measure. Standardized measure does not give effect to derivative transactions.

Undeveloped Acreage: Acreage owned or leased on which wells can be drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Unit: A contiguous geographic area that was established and approved by state oil and gas commissions for the express purpose of secondary recovery.

Unitization: The process of obtaining approval from working interest owners, mineral owners and regulatory agencies to conduct secondary (e.g., waterflooding) or tertiary operations.

Wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

Working Interest: The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover: Operations on a producing well to restore or increase production.

WTI: West Texas Intermediate, also called Texas light sweet, is defined as a type of crude oil as a benchmark in oil price and is the underlying commodity of New York Mercantile Exchanges oil future contracts.

NAMES OF ENTITIES

As used in this Form 10-K, unless we indicate otherwise:

- *"Founders" collectively refers to Charles R. Olmstead, S. Craig George and Jeffrey R. Olmstead;*
- *"our general partner" refers to Mid-Con Energy GP, LLC;*
- *"Mid-Con Affiliate" refers to Mid-Con Energy III, LLC and its subsidiaries, which is an affiliate of our general partner;*
- *"ME3 Oilfield Service" refers to ME3 Oilfield Service, LLC which is a wholly owned subsidiary of our Mid-Con Affiliate;*
- *"Mid-Con Energy Partners," the "partnership," "we," "our," "us" or like terms when used refer to Mid-Con Energy Partners, LP, a Delaware limited partnership, and its subsidiaries;*
- *"Mid-Con Energy Operating" refers to Mid-Con Energy Operating, LLC, an affiliate of our general partner;*
- *"Mid-Con Energy Properties" refers to Mid-Con Energy Properties, LLC, our wholly owned subsidiary;*
- *"our predecessor" collectively refers to Mid-Con Energy Corporation, prior to June 30, 2009, and to Mid-Con Energy I, LLC and Mid-Con Energy II, LLC, on a combined basis, thereafter, our respective predecessors for accounting purposes; and*
- *"Yorktown" collectively refers to Yorktown Partners LLC, Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., Yorktown Energy Partners VIII, L.P., Yorktown Energy Partners IX, L.P. and/or Yorktown Energy Partners X, L.P.*

FORWARD-LOOKING STATEMENTS

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

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

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Item 1. "Business," Item 1A. "Risk Factors," Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report on Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," "goal," "forecast," "guidance," "might," "scheduled" and the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K 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 Annual Report on Form 10-K 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 and elsewhere in this Annual Report on Form 10-K. 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.

PART I

ITEM 1. BUSINESS

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

Overview

We operate as one business segment engaged in the ownership, acquisition, exploitation and development of producing oil and natural gas properties. Our properties are located primarily in the Mid-Continent and Permian Basin regions of the United States in five core areas: Southern Oklahoma, Northeastern Oklahoma, parts of Oklahoma, Colorado and Texas within the Hugoton, Texas Gulf Coast and Texas within the Eastern Shelf of the Permian. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Our management team has significant industry experience, especially with waterflood projects and, as a result, our operations focus primarily on enhancing the development of producing oil properties through waterflooding. Waterflooding, a form of secondary oil recovery, works by displacing or “sweeping” oil to producing wellbores. Through the continued development of our existing properties and through future acquisitions, we will seek to increase our reserves and production in order to make and, over time, increase distributions to our unitholders. Also, in order to enhance the stability of our cash flow for the benefit of our unitholders, we generally intend to hedge a portion of our production volumes through various commodity derivative contracts.

As of December 31, 2015, our total estimated proved reserves were approximately 22.3 MMBoe, of which approximately 95% were oil and 68% were proved developed, both on a Boe basis. As of December 31, 2015, we operated approximately 100% of our properties through our affiliate, Mid-Con Energy Operating and 67% of our net proved reserves were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended December 31, 2015 was approximately 4,676 Boe per day and our total estimated proved reserves had an average reserve-to-production ratio of approximately 13 years.

The following table summarizes information by core area regarding our estimated net proved oil and natural gas reserves, count of gross wells, reserve-to-production ratio and our average net production for the month ended December 31, 2015:

	Estimated Net Proved Reserves				December 2015 Average Net Production			Gross Active Wells		
Core Area	(MBoe)	% Operated [1]	% Oil	% Proved Developed	Boe/d Gross	Boe/d Net	Reserve-to-Production Ratio [2]	Oil and Natural Gas Wells	Injection, Disposal or Water Supply Wells	Gross Shut-in or Waiting on Completion
Southern Oklahoma	3,071	100%	100%	80%	1,713	890	9	98	68	20
Northeastern Oklahoma	8,916	100%	95%	72%	1,643	1,369	18	226	102	307
Hugoton	3,212	100%	99%	78%	852	682	13	70	50	86
Permian	6,524	100%	89%	55%	2,299	1,685	11	172	54	68
Gulf Coast	529	100%	100%	36%	74	50	29	6	4	2
Total	22,252	100%	95%	68%	6,581	4,676	13	572	278	483

(1) Operated through our affiliate, Mid-Con Energy Operating. Less than .01% of our net proved reserves are operated by others.
(2) The reserve to production ratio is calculated by dividing estimated net proved reserves as of December 31, 2015 by average net production for the month ended December 31, 2015.

2015 Highlights

Operational and Financial Performance

- Net production in 2015 averaged 4,707 Boe/d, up approximately 51% from 2014
- LOE of $19.55/Boe in 2015 was a decrease of approximately 15% from 2014
- G&A averaged $5.48/Boe, a decrease of approximately 56% from 2014
- Free cash from operations funded $25.0 million in debt reductions along with approximately $14.0 million in capital development spending during 2015
- 2015 leverage ratio of 3.27x declined 0.24x from 2014

Financing Activities

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

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

During November 2015, the semi-annual borrowing base redetermination and amendment of our underlying revolving credit facility was completed. The redetermination resulted in a decrease of our borrowing base from $220.0 million to $190.0 million, consisting of a $165.0 million conforming tranche, which includes monthly commitment reductions of $2.5 million each mandated through May 2016, and a $25.0 million non-conforming tranche. The credit facility amendment also designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. See Note 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Equity Awards

On November 20, 2015, the unitholders approved an amendment to the Long-Term Incentive Program that increased the number of common units available for issuance under the program from 1,764,000 to 3,514,000 common units. See our Form S-8 filed on November 25, 2015 with the SEC for further details.

Our Business Strategies

Our primary business objective is to generate stable cash flows, which we expect will allow us to make quarterly cash distributions to our unitholders and, over time, to increase our quarterly cash distributions. In addition to our hedging strategy described below, we intend to execute the following business strategies:

- ***Continue exploitation of our existing properties to maximize production.*** We plan to continue exploiting our proved reserves to maximize production, primarily through waterflood projects and through various oil recovery methods, including workovers, conventional hydraulic fracturing, re-stimulations, recompletions, infill drilling and other optimization activities. We expect to continue these activities in order to maximize economic production volumes.
- ***Pursue acquisitions of long-lived, low-risk producing properties with upside potential.*** We will seek to acquire properties with long-lived reserves, low production decline rates and low-risk development potential. We also will seek to acquire properties within mature oil fields with opportunities for incremental improvements in oil recovery through waterfloods and other recovery techniques, which we believe will offer us additional potential to increase reserves, economic production volumes and cash flows.
- ***Capitalize on our relationship with our Mid-Con Affiliate for favorable acquisition opportunities.*** We expect that our Mid-Con Affiliate will continue to invest capital and technical staff resources to acquire and develop properties with existing waterfloods and to identify, acquire, form and develop new waterflood projects on those properties. Through this relationship with our Mid-Con Affiliate, we plan to avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. While they are not obligated to sell any properties to us and may have difficulties acquiring and developing properties, we expect that our Mid-Con Affiliate will offer to sell properties to us from time to time. We believe

that the opportunity to acquire properties from our Mid-Con Affiliate provides us with a strategic advantage over those of our competitors who must bear a greater share of development risks themselves.

- ***Maintain operational control and a focus on cost effectiveness in all our operations.*** As of December 31, 2015, Mid-Con Energy Operating operated approximately 100% of our properties, calculated on a Boe basis. We plan to continue exercising this level of operational control over our existing properties and favor acquisitions of operated properties in order to manage the timing and levels of our capital expenditures, development activities and operating costs.
- ***Reduce the impact of commodity price volatility on our cash flows through a disciplined commodity hedging strategy.*** We seek to reduce the impact of commodity price volatility on our cash flows by maintaining a portfolio of commodity derivative contracts to help offset the underlying volatility of oil and natural gas prices. As opposed to entering into commodity derivative contracts at predetermined times or on prescribed terms, we enter into commodity derivative contracts in connection with material increases in our estimated production, at times when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the prices, percentages of our hedged production volumes or the duration of our commodity derivative contracts when circumstances suggest that it is prudent to do so.
- ***Employ equity as our primary currency for acquisitions.*** We intend to maintain an equity-weighted bias towards acquisition financing. Although the cost of equity financing is generally more costly than debt financing, we believe the resulting conservatism and financial flexibility merit the incremental expense of continuing to rely on equity as our primary currency to fund acquisitions.
- ***Utilize compensation programs that align the interest of our management team with our unitholders .*** We tie the compensation of our executives and directors directly to achieving our strategic, operating and financial goals and have adopted compensation programs that place a significant part of the pay of each of our executives "at risk" in the form of an annual short-term incentive awards and long-term, equity-based incentive grants. The amount of the annual short-term incentive awards paid depends on our performance against financial and operating objectives as well as the executive meeting key leadership and development standards. A portion of the compensation of our executives is also in the form of equity awards that tie their compensation directly to creating unitholder value over the long-term. We believe this combination of annual short-term incentive awards and long-term equity awards aligns the incentives of our management with our unitholders.

Our Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies and achieve our objective of generating and growing cash available for distribution:

- ***An asset portfolio largely consisting of properties with existing waterflood projects with proved reserves, of which 95% are oil, and relatively predictable production profiles that provide growth potential through ongoing response to waterflooding and that have modest capital requirements.*** Our properties consist of interests in mature fields located in Oklahoma, Colorado and Texas that have well-understood geologic features, relatively predictable production profiles and modest capital requirements, which we believe make them well-suited for waterflood development and for our objective of generating stable cash flows. Currently, over 67% of our net proved reserves on a Boe basis are being produced under waterflood. Based on production estimates from our December 31, 2015 audited reserves, the average estimated decline rate for our existing proved developed producing reserves is approximately 13.1% for 2016 and, on a compounded average decline basis, approximately 10.0% for the subsequent five years and approximately 8.5% thereafter. Further, we believe that a substantial majority of the capital required for growth from our existing properties has already been spent. As a result, these properties have relatively predictable production profiles and production growth potential with modest capital requirements.
- ***The ability to further exploit existing mature properties by utilizing our waterflood expertise.*** We have actively operated a significant portion our properties since 2005 and have a history of exploiting proved reserves to maximize production, primarily through waterflood projects. Over the last ten years, we identified, initiated, acquired, formed and developed over 11% of all new waterflood projects in the state of Oklahoma, while the next most active competitor formed only 7% of all new waterfloods. Furthermore, our experience in the Mid-Continent allows us to exploit synergies developed by applying knowledge of field, reservoir and play characteristics throughout North America. We believe that our expertise in secondary recovery techniques will increase the level of production from certain properties in our portfolio, particularly from existing waterflood projects, which, over time, may increase our cash flows.

- ***Acquisition opportunities that are consistent with our criteria of predictable production profiles with upside potential that may arise as a result of our relationship with the Mid-Con Affiliate.*** We expect that our Mid-Con Affiliate will continue to invest capital and technical staff resources to acquire and develop properties with existing waterfloods and to identify, acquire, form and develop new waterflood projects on those properties. Through this relationship with our Mid-Con Affiliate, we plan to avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. While they are not obligated to sell any properties to us and may have difficulties acquiring and developing properties, we expect that our Mid-Con Affiliate will offer to sell properties to us from time to time. We believe that the opportunity to acquire properties from our Mid-Con Affiliate provides us with a strategic advantage over those of our competitors who must bear a greater share of development risks themselves.
- ***Access to the collective expertise of Yorktown's employees and their extensive network of industry relationships through our relationship with Yorktown.*** Yorktown Energy Partners ("Yorktown") is a private investment firm focused on investments in the energy sector with more than $4.0 billion in assets under management. With their decades of investment experience in the oil and natural gas industry and their extensive network of industry relationships, Yorktown's employees are well positioned to assist us in identifying and evaluating acquisition opportunities and in making strategic decisions.
- ***Mid-Con Energy Operating operates approximately 100% of our properties, which allows them to control our operating costs and capital expenditures*** . As of December 31, 2015, Mid-Con Energy Operating operated approximately 100% of our properties, as calculated on a Boe basis, which allowed it to control our operating costs and capital expenditures. We expect to continue exercising this level of operational control over our properties, including any properties we acquire through future acquisitions, which allows us to better manage our operating costs and capital expenditures. This substantial operational control of our producing properties also allows us to maximize the value of our properties, helps us stabilize our cash flows and affords us better control over the timing and costs of our operations.
- ***The range and depth of our technical and operational expertise allows us to expand both geographically and operationally to achieve our goals.*** We have assembled a senior team of geologists, engineers, landmen, accountants and operational personnel that have been successful in developing a significant number of new waterflood projects. Collectively, our management and employees have prior waterflood experience in over 250 waterflood projects located in ten states. Through our affiliate, Mid-Con Energy Operating, we have a team of over 90 employees, with senior leadership in all production disciplines, and we have recruited a select group of younger professionals that are being trained in our waterflood specialty. With this expertise and depth, we believe this team has the ability to generate new waterflood projects that may become future acquisition opportunities for us. Beyond our core strength of waterflood development, our range and depth of expertise will allow us to expand both geographically and operationally. Although our projects to date have been focused on waterfloods in the Mid-Continent and Permian regions, our management and operational employees have significant oil and gas experience in many other regions of the United States. Our wealth of experience enables us to pursue other types of exploitation opportunities, such as infill drilling projects that could significantly contribute to our strategy of generating stable cash flow and, over time, increasing our quarterly cash distributions.

Hedging Strategy

Our hedging program's objective is to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and NYMEX WTI futures prices. As of December 31, 2015, we had commodity derivative contracts covering approximately 81% and 46% of our estimated production (estimate based on the mid-point of 2016 production guidance as released on February 29, 2016) for calendar years 2016 and 2017, respectively. At December 31, 2015, our derivative contracts had maturities in 2016 and 2017 and were comprised of commodity price swap, call and put contracts.

In January 2015, we restructured a portion of our commodity derivative contracts in place at December 31, 2014 resulting in our total commodity derivative contracts covering approximately 74% and 57% of our estimated oil production (estimate based on the mid-point of 2015 production guidance at a 95% oil weighting) for calendar years 2015 and 2016, respectively. The new commodity derivative contracts were extended through September 2016. The restructuring achieved more predictable cash flows and reduced exposure to fluctuations in the price of oil in 2015 and 2016 while also protecting the borrowing base of our reserve based revolving credit facility against further oil price weakness and improving compliance with our revolving credit facility's leverage covenants.

Regarding the restructuring of our commodity derivative contracts in January 2015, we received net proceeds of approximately $11.1 million from the early termination of contracts on January 22 and 23, 2015, received approximately $5.9 million from selling call contracts and paid out approximately $19.8 million in premiums to enhance at the market swap contracts through September 2016. The restructuring also resulted in approximately $4.1 million in deferred premium put options. As of December 31, 2015, we had paid $1.9 million of the deferred put premiums in connection with derivative contract settlements. These transactions provided an additional $23.8 million of cash flows for 2015.

In connection with the semi-annual redetermination of our borrowing base in November 2015, we entered entered into additional commodity derivative contracts resulting in our total commodity derivative contracts covering at least 80% of 2016 projected monthly production and at least 50% of 2017 projected monthly production. In addition to our primary hedging strategy as described above, we also intend to enter into additional commodity derivative contracts in connection with material increases in our estimated production and at times when we believe market conditions or other circumstances suggest that it is prudent to do so. It is not our strategy to enter into commodity derivative contracts at predetermined times or on prescribed terms. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the prices, percentages of our hedged production volumes or the duration of our commodity derivative contracts when circumstances suggest that it is prudent to do so.

By removing a portion of price volatility associated with our estimated future oil production, we have mitigated, but not eliminated, the potential effects of changing oil prices on our cash flows from operations for those periods. For a further description of our commodity derivative contracts, please read “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Derivative Contracts.”

Our Principal Business Relationships

Our Relationship with our Mid-Con Affiliate

Our Mid-Con Affiliate acquires and develops oil and natural gas properties that are either undeveloped or that may require significant capital investment and development efforts before they meet our criteria for ownership. As these development projects mature, we expect to have the opportunity to acquire some of these properties from our Mid-Con Affiliate. Through this relationship with our Mid-Con Affiliate, we will avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. However, our Mid-Con Affiliate may not be successful in identifying or consummating acquisitions or in successfully developing the new properties they acquire. Further, our Mid-Con Affiliate is not obligated to sell any properties to us, and they are not prohibited from competing with us to acquire oil and natural gas properties.

Services Agreement

Our subsidiaries and our general partner have a services agreement with Mid-Con Energy Operating. Pursuant to the services agreement, Mid-Con Energy Operating provides certain services to us, our subsidiaries and our general partner, including management, administrative and operational services, which include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. Mid-Con Energy Operating has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate back to us. Mid-Con Energy Operating will not be liable to us for its performance of, or failure to perform, services under the services agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Our Relationship with Yorktown

We have a valuable relationship with Yorktown, a private investment firm founded in 1991 and focused on investments in the energy sector. Since 2004, Yorktown has made several equity investments in our predecessor. Peter A. Leidel, a principal of Yorktown, serves on our Board of Directors.

Yorktown currently has more than $4.0 billion in assets under management and Yorktown’s employees have extensive investment experience in the oil and natural gas industry. Yorktown’s employees review a large number of potential acquisitions and are involved in decisions relating to the acquisition and disposition of oil and natural gas assets by the various portfolio companies in which Yorktown owns interests. With their extensive investment experience in the oil and natural gas industry and their extensive network of industry relationships, Yorktown’s employees are well positioned to assist us in identifying and evaluating acquisition opportunities and in making strategic decisions. Yorktown is not obligated to sell any properties to us, and they are not prohibited from competing with us to acquire oil and natural gas properties. Investment funds managed by Yorktown manage numerous other portfolio companies, including our Mid-Con Affiliate, which is engaged in the oil and natural gas industry and, as a result, Yorktown may present acquisition opportunities to other Yorktown portfolio companies that compete with us.

Our Areas of Operation

As of December 31, 2015, our properties were primarily located in the Mid-Continent and Permian regions of the United States in five core areas: Southern Oklahoma, Northeastern Oklahoma, parts of Oklahoma, Colorado and Texas within the Hugoton, Texas Gulf Coast and Texas within the Eastern Shelf of the Permian. These core areas are generally composed of multiple waterflood units that are in close proximity to one another, produce from geologically similar reservoirs and utilize similar recovery methods. Focusing on these core areas allows us to apply our cumulative technical and operational knowledge to ongoing property development and to better predict future rates of recovery. For a discussion of the properties in our core areas, please see "Summary of Oil Properties and Projects."

Our properties consist of mature, legacy onshore oil reservoirs, approximately 67% of the reserves of which are being produced under waterflooding, on a Boe basis. Our properties include multiple waterflood projects with varying degrees of maturity.

We own an average working interest of approximately 92% across 572 gross (512 net) producing wells, 278 gross (246 net) injection, water supply or disposal wells, and 483 gross (463 net) wells shut-in or waiting on completion and operate approximately 100% of our properties by value, as calculated using our estimated net proved reserves as of December 31, 2015. Approximately 98% of our revenue is derived from the proceeds of oil production.

Our estimated proved reserves as of December 31, 2015 were approximately 22.3 MMBoe, of which approximately 95% were oil and approximately 68% were proved developed, both on a Boe basis. For the month ended December 31, 2015, we produced an average of approximately 4,676 Boe per day.

The following table shows our estimated net proved oil reserves for our core areas, based on a reserve report prepared by our internal reserve engineers and audited by Cawley, Gillespie & Associates, Inc., our independent petroleum engineers, as of December 31, 2015, and certain unaudited information regarding production and sales of oil and natural gas with respect to such properties:

	Average Net Production For the Month Ended December 31, 2015		Estimated Net Proved Reserves as of December 31, 2015					
Core Area	**Net (Boe/d)**	**% of Total**	**MBoe**	**% of Total Proved Reserves**	**% Oil**	**% Proved Developed Reserves**	**PV-10 (1)(2) ($ in millions)**	**% of Total**
Southern Oklahoma	890	19%	3,071	14%	100%	80%	$ 30	16%
Northeastern Oklahoma	1,369	29%	8,916	40%	95%	72%	$ 74	39%
Hugoton	682	15%	3,212	15%	99%	78%	$ 12	6%
Permian	1,685	36%	6,524	29%	89%	55%	$ 67	35%
Gulf Coast	50	1%	529	2%	100%	36%	$ 8	4%
Total	4,676	100%	22,252	100%	95%	68%	$ 191	100%

(1) Our Standardized Measure at December 31, 2015 was $191.4 million. Because we are a partnership, we made no provision for federal or state income taxes in the calculation of standardized measure. The present value of future net pre-tax cash flows attributable to estimated net proved reserves, discounted at 10% per annum ("PV–10"), is a computation of the standardized measure of discounted future net cash flows on a pre–tax basis. PV–10 is computed on the same basis as standardized measure but does not include a provision for federal or state income taxes. PV–10 is considered a non–GAAP financial measure under the regulations of the Securities and Exchange Commission (the "SEC"). We believe PV–10 to be an important measure for evaluating the relative significance of our oil and natural gas properties. We further believe investors and creditors may utilize our PV–10 as a basis for comparison of the relative size and value of our reserves to other companies. PV–10, however, is not a substitute for the standardized measure. Our PV–10 measure and the standardized measure do not purport to present the fair value of our reserves.

(2) Our estimated net proved reserves and standardized measure were computed by applying average trailing 12- month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable 12-month period, held constant throughout the life of the properties). These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The average trailing 12-month index prices were $50.28
per Bbl for oil and $2.58 per MMBtu for natural gas for the 12 months ended December 31, 2015.

All proved undeveloped locations conform to SEC rules for recording proved undeveloped reserves. None of our proved undeveloped reserves as of December 31, 2015 have remained undeveloped for more than five years from the date the reserves were initially booked as proved undeveloped.

Summary of Oil Properties and Projects

Our core areas detailed below represent all of our total estimated net proved reserves and our standardized measure as of December 31, 2015 and all of our average daily net production for the month ended December 31, 2015. The following is a summary of each of our properties within our core areas. All of the following descriptions are based on our December 31, 2015 audited reserve report.

Southern Oklahoma

Our Southern Oklahoma properties are located in Love and Carter Counties, Oklahoma. The Southern Oklahoma properties are part of seven waterflood units operated by Mid-Con Energy Operating, six of which were unitized by Mid-Con Energy Operating. During December 2015, our properties in these fields produced on average 1,713 Boe per day gross, 890 Boe per day net, and contained 3,071 MBoe of estimated net proved reserves. We acquired additional interests in these properties in May 2013 and May 2014 and have an average working interest of approximately 66% in 98 producing, 63 injection and 5 water supply wells (gross). During 2015, we drilled 1 gross producing well and converted 1 gross injection well to a producing well.

Northeastern Oklahoma

Our Northeastern Oklahoma properties are located in four counties in Oklahoma: Seminole, Creek, Osage and Pawnee Counties. The majority of our properties are being produced under waterflood and are operated by Mid-Con Energy Operating. The Cleveland Field was unitized in April 2013 as a waterflood unit. During December 2015, our properties in these fields produced on average 1,643 Boe per day gross, 1,369 Boe per day net and contained 8,916 MBoe of estimated net proved reserves. We acquired additional interests in these properties in May 2013 and acquired additional properties in August 2014. Our average working interest in these properties is approximately 96% in 226 producing, 85 injection, 15 disposal and 2 water supply wells (gross). During 2015, we drilled 6 gross producing wells and converted 7 gross producing wells to injection wells.

Hugoton

Our Hugoton properties are located in three fields in Cimarron County and Texas County, Oklahoma, Potter County, Texas and Cheyenne County, Colorado. The Hugoton properties are part of eight waterflood units operated by Mid-Con Energy Operating, one of which Mid-Con Energy Operating unitized. During December 2015, our properties in these units produced on average 852 Boe per day gross, 682 Boe per day net and contained 3,212 MBoe of estimated net proved reserves. We acquired additional properties in February 2014 and have an average working interest of approximately 97% in 70 producing, 45 injection and 5 water supply wells (gross). During 2015, we converted 3 gross producing wells to injection wells.

Permian

Our Permian properties are located in eleven counties in Texas: Coke, Coleman, Fisher, Haskell, Jones, Kent, Nolan, Runnels, Stonewall, Taylor and Tom Green Counties, Texas. We acquired these properties in November 2014. The Permian properties have three waterflood units operated by Mid-Con Energy Operating. During December 2015, our properties in these fields produced on average 2,299 Boe per day gross, 1,685 Boe per day net and contained 6,524 MBoe of estimated net proved reserves. We have an average working interest of approximately 94% in 172 producing, 35 injection, 16 disposal and 3 water supply wells (gross). During 2015, we drilled 5 gross producing wells, 1 gross water supply well and converted 3 gross producing wells to injection wells.

Gulf Coast

Our Gulf Coast property is located in Liberty County, Texas. We acquired the waterflood unit in August 2014, and it is operated by Mid-Con Energy Operating. During December 2015, this waterflood produced on average 74 Boe per day gross, 50 Boe per day net and contained 529 MBoe of estimated net proved reserves. We have an average working interest of approximately 92% in 6 producing, 3 injection and 1 water supply wells (gross). During 2015, we drilled 1 gross producing well and converted 1 gross producing well to injection.

Oil and Natural Gas Reserves and Production

Internal Controls Relating to Reserve Estimates

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our internal controls over the recording of reserves estimates require reserve estimates to be in compliance with the SEC rules, regulations, definitions and guidance. Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by our reservoir engineering staff. Internal evaluations of our reserves are maintained in a secure reserve engineering database. Reserves are reviewed internally by our senior management on a quarterly basis. Our reserve estimates are audited by our independent third-party reserve engineers, Cawley, Gillespie & Associates, Inc., at least annually.

Our staff works closely with Cawley, Gillespie & Associates, Inc. to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve audit process. To facilitate their audit of our reserves, we provide Cawley, Gillespie & Associates, Inc. with any information they may request, including all of our reserve information as well as geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures, lease operating expenses, product pricing, production taxes and relevant economic criteria. We also make all of our pertinent personnel available to Cawley, Gillespie & Associates, Inc. to respond to any questions they may have.

Technology Used to Establish Proved Reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs and under existing economic conditions, operating methods and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Cawley, Gillespie & Associates, Inc. employ technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, injection data, seismic data and well test data. Reserves attributable to producing properties with sufficient production history are estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing properties with limited production history and for undeveloped locations are estimated using performance from analogous properties in the surrounding area and geologic data to assess the reservoir continuity. These properties were considered to be analogous based on production performance from the same formation and similar completion techniques.

Qualifications of Responsible Technical Persons

Cawley, Gillespie & Associates, Inc. is an independent oil and natural gas consulting firm. No director, officer, or key employee of Cawley, Gillespie & Associates, Inc. has any financial ownership in the Mid-Con Affiliate, Mid-Con Energy Operating or any of their respective affiliates. Cawley, Gillespie & Associates, Inc.’s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported. The engineering audit presented in the Cawley, Gillespie & Associates, Inc. report was overseen by Bob Ravnaas, P.E., Executive Vice President. Mr. Ravnaas is an experienced reservoir engineer having been a practicing petroleum engineer since 1981. He has more than 30 years of experience in reserves evaluation. Mr. Ravnaas received a Bachelor of Science with special honors in Chemical Engineering from the University of Colorado at Boulder in 1979 and a Master of Science in Petroleum Engineering from the University of Texas at Austin in 1981. He is a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, the American Association of Petroleum Geologists and the Society of Petrophysicists and Well Log Analysts.

Dr. Chad B. Roller, Ph.D., is our Vice President of Exploitation and has served in this role since March 2015. Dr. Roller previously served as Petroleum Engineer at Mid-Con Energy and Royal Dutch Shell where his expertise includes waterflood development and enhanced oil recovery. Dr. Roller received his Ph.D. from Rice University in 2005 and Master of Science and Bachelor of Science degrees from the University of Oklahoma in 2002 and 2001, respectively.

Estimated Proved Reserves

The following table presents our estimated net proved oil and natural gas reserves associated with our estimated proved reserves attributable to our properties as of December 31, 2015, based on reserve reports prepared by our reservoir engineering staff and audited by Cawley, Gillespie & Associates, Inc.

	Net Oil MBbls	Net Gas MMcf	Total Net MBoe (2)
Reserve Data (1)			
Estimated proved developed reserves	14,368	4,762	15,162
Estimated proved undeveloped reserves	6,746	2,065	7,090
Total	21,114	6,827	22,252

(1) Our estimated net proved reserves were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month price for the prior twelve months were $50.28 per Bbl for oil and $2.58 per MMBtu for natural gas at December 31, 2015. These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Average adjusted prices used were $47.23 per Bbl of oil and $2.02 per Mcf of natural gas.

(2) MBoe is based on a natural gas conversion factor of 6 Mcf to 1 Boe.

The data in the table above represent estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil that are ultimately recovered. For a discussion of risks associated with internal reserve estimates, see “Item 1A. Risk Factors — Risks Related to Our Business.” Our estimated proved reserves and future production rates rely on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure amounts should not be construed as the current market value of our estimated oil reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Production, Revenue and Price History

For a description of the Partnership’s historical production, revenues and average sales prices and unit costs, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations.”

Development of Proved Undeveloped Reserves

None of our proved undeveloped reserves at December 31, 2015 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. Consistent with the typical waterflood response time range of six to eighteen months from initial development, the transfer of proved undeveloped reserves to the proved developed category is attributable to development costs incurred in prior years. During 2015, our capital expenditures for development (drilling, recompletion and conversion to injection) were approximately $4.9 million. Based on our current expectations of our cash flows, we plan to reduce our 2016 capital spending budget for the development of our proved undeveloped reserves and look for development opportunities that can be funded from our cash flows from operations. For a more detailed discussion of our pro forma liquidity position, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

For the period from December 31, 2014 through December 31, 2015, our proved undeveloped reserves increased from 5,297 MBoe to 7,090 MBoe. The upward revision in our proved undeveloped reserves is largely attributable to evaluations of waterflood and infill drilling projects in the Permian, Northeastern Oklahoma, and Hugoton core areas. In our Gulf Coast core area, a producing well failure due to casing collapse in the Liberty South (Yegua) Unit necessitated the reclassification of approximately 442 MBoe from proved developed producing reserves to proved undeveloped reserves. A replacement producing well was spud in the third quarter of 2015 and completion was in process at December 31, 2015. The refinement of our drilling program contributed to the removal of proved undeveloped reserves in our Cushing field (Northeast Oklahoma) no longer scheduled to be drilled within five years from the date in which they were first booked. One element leading to the removal is an increased emphasis on an expanded drilling and recompletions program in our Permian core area following a successful drilling program in 2015, which resulted in a positive revision of our proved developed reserves of 540 MBoe. The following table provides further details with respect to various factors that impacted the changes in our proved undeveloped reserves during 2015 (MBoe):

	Net Oil MBbls	Net Gas MMcf	Total Net MBoe
Proved Undeveloped Reserves as of December 31, 2014	5,094	1,215	5,297
Transferred to proved developed through drilling & development	(994)	—	(994)
Revisions of previous estimates (1)	(516)	(139)	(540)
Improved recovery (2)	3,240	989	3,405
Acquisitions	—	—	—
Reduction due to aged five or more years	(78)	—	(78)
Proved Undeveloped Reserves as of December 31, 2015	6,746	2,065	7,090

(1) Revisions due to product price changes.

(2) Added reserves through EOR and infill drilling activities.

Development Activities

Since January 2015, we undertook a paced development program consisting of drilling approximately 13 gross (12.5 net) development wells, the majority of which reside in our Permian and Northeastern Oklahoma core areas. As part of our waterflood development program, approximately 14 gross (13 net) producing wells were converted to injection wells with the majority of the conversions taking place in our Cleveland Unit in Northeastern Oklahoma. We will continue our development program and look for additional opportunities that can be funded from our cash flows from operations in 2016.

In our Permian core area, we drilled 5 gross (5 net) development wells in the Corsica Strawn, White Flats and Len Bryans fields. We continue to evaluate these properties for additional drilling opportunities and waterflood potential.

In our Northeastern Oklahoma core area, we have been engaged in an active exploitation program in our Cleveland Field. During 2013, we unitized our Cleveland Field operations and this has allowed us to enhance our exploitation strategy with a positive impact on production. In August 2014, we acquired additional properties in Creek County, Oklahoma. In 2015 we drilled 6 gross (6 net) development wells in our Northeastern Oklahoma core area.

The following table sets forth information with respect to development activities during the periods indicated. The information should not be considered indicative of future performance nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Developmental wells:						
Productive	13	13	47	44	22	17
Injection	—	—	4	4	8	6
Water Supply	1	1	1	1	1	1
Dry	1	1	2	1	—	—
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	13	13	47	44	22	17
Injection	—	—	4	4	8	6
Water Supply	1	1	1	1	1	1
Dry	1	1	2	1	—	—
Total	15	15	54	50	31	24

We are in the process of completing 1 gross (1 net) recently drilled well in our Permian core area.

Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2015. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Gross Wells			Net Wells		
	Operated	Non-operated	Total	Operated	Non-operated	Total
Oil	568	1	569	512	—	512
Natural Gas	—	3	3	—	1	1
Injection	231	—	231	203	—	203
Disposal	31	—	31	30	—	30
Water Supply	16	—	16	13	—	13
Shut-in or Waiting on Completion	483	—	483	463	—	463
Total	1,329	4	1,333	1,221	1	1,222

Production by Field

The following table sets forth our production for 2015, 2014 and 2013 from each of our fields that we represent as our core areas:

	Year Ended December 31,					
	2015		2014		2013	
Core Area	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Southern Oklahoma	354	10	428	8	491	34
Northeastern Oklahoma	482	165	344	73	199	48
Hugoton	273	14	269	20	210	25
Permian	502	379	53	37	—	—
Gulf Coast	12	2	12	1	—	—
Total	1,623	570	1,106	139	900	107

Developed Acreage

The following table sets forth information relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table. As of December 31, 2015, approximately 94% of our leasehold acreage was held by production:

Core Area	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Southern Oklahoma	8,744	6,454	—	—
Northeastern Oklahoma	8,529	7,462	—	—
Hugoton	14,146	13,998	—	—
Permian	14,500	13,792	3,045	2,747
Gulf Coast	541	485	—	—
Total	46,460	42,191	3,045	2,747

The Southern Oklahoma, Northeastern Oklahoma, Hugoton and Gulf Coast areas do not have any undeveloped acreage because all of our proved undeveloped reserves are related to new drilling or recompletion activities within currently producing areas of our developed acreage and represent in-fill or reduced spacing activity.

Delivery Commitments

We have no commitments to deliver a fixed and determinable quantity of our oil or natural gas production in the near future under our existing contracts.

Operations

General

We operate approximately 100% of our properties, as calculated on a Boe basis as of December 31, 2015, through our affiliate, Mid-Con Energy Operating. All of our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies. We design and manage the development, recompletion or workover for all of the wells we operate and supervise operation and maintenance activities. We do not own the drilling rigs or other oil field services equipment used for drilling or maintaining wells on the properties we operate.

We engage numerous independent contractors in each of our core areas to provide all of the equipment and personnel associated with our drilling and maintenance activities, including well servicing, trucking and water hauling, bulldozing, and various downhole services (e.g., logging, cementing, perforating and acidizing). These services are short-term in duration (often being completed in less than a day) and are typically governed by a one-page service order that states only the parties' names, a brief description of the services and the price.

We also engage several independent contractors to provide hydraulic fracturing services. These services are usually completed in four to six hours utilizing lower pressures and volumes of fluid than are typically employed in connection with multi-stage hydraulic fracturing jobs performed in connection with unconventional oil and gas shale plays. These services are not normally governed by long-term services contracts, but instead are generally performed under one-time service orders, which state the parties' name and the price. These service orders sometimes contain additional terms addressing, for example, taxes, payment due dates, warranties and limitations of the contractor's liability to damages arising from the contractor's gross negligence or willful misconduct.

Geological and Engineering Services

Mid-Con Energy Operating employs production and reservoir engineers, geologists and land specialists, as well as field production supervisors. Through the services agreement, we have the direct operational support of a staff of over 40 petroleum professionals with significant technical expertise. We believe that this technical expertise, which includes extensive experience utilizing secondary recovery methods, particularly waterfloods, differentiates us from, and provides us with a competitive advantage over, many of our competitors. Please see Item 13. "Certain Relationships and Related Transactions, and Director Independence — Reimbursement of Expenses" for more information.

Administrative Services

Mid-Con Energy Operating provides us with management, administrative and operational services under the services agreement. We reimburse Mid-Con Energy Operating, on a cost basis, for the allocable expenses it incurs in performing these services. Mid-Con Energy Operating has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us. For a detailed description of the administrative services provided by Mid-Con Energy Operating pursuant to the services agreement, please see Item 13. "Certain Relationships and Related Transactions, and Director Independence — Reimbursement of Expenses."

Oil and Natural Gas Leases

The typical oil lease agreement covering our properties provides for the payment of royalties to the mineral owner for all hydrocarbons produced from any well drilled on the lease premises. The lessor royalties and other leasehold burdens on our properties range from less than 12.5% to 33.5%, resulting in a net revenue interest to us ranging from 66.5% to 87.5% on a 100% working interest basis. Our average net revenue interest is 76.6%. Most of our leases are held by production and do not require lease rental payments.

Principal Customers

For the year ended December 31, 2015, sales of oil and natural gas to BML, Inc ("BML"), Enterprise Crude Oil, LLC (“Enterprise”) and Coffeyville Resources Refining & Marketing, LLC ("Coffeyville") accounted for approximately 31%, 22% and 21%, respectively, of our sales.

The loss of any of our customers could temporarily delay production and sale of our oil and natural gas. If we were to lose any of our significant customers, we believe we could identify substitute customers to purchase the impacted production volumes. However, if any of our customers dramatically decreased or ceased purchasing oil from us, we may have difficulty finding substitute customers to purchase our production volumes at comparable rates.

Hedging Activities

We continue to enter into commodity derivative contracts with unaffiliated third parties that are also participants in our revolving credit facility to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas prices. At December 31, 2015, our commodity derivative contracts had maturities in 2016 and 2017 and were comprised of price swap, call and put contracts. For a more detailed discussion of our hedging activities, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources” and “Item 7A. Quantitative and Qualitative Disclosure About Market Risk — Commodity Price Risk.”

Competition

We operate in a highly competitive environment for acquiring properties and securing trained personnel. Many of our competitors possess and employ financial resources substantially greater than ours, which can be particularly important in the areas in which we operate. These companies may have a greater ability to continue acquisition, and or exploration and production activities during periods of low commodity prices. Some of our competitors may also possess greater technical and personnel resources than us. As a result, our competitors may be able to pay more for productive oil properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to acquire and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry.

At times, we may also be affected by competition for drilling rigs, completion rigs and the availability of related equipment and services. In recent years, the United States onshore oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and caused significant increases in the price for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation programs.

Title to Properties

Prior to completing an acquisition of producing oil properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties. After an acquisition, we review the assignments from the seller for scrivener’s and other errors and execute and record corrective assignments as necessary.

We initially conduct only a review of the titles to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We believe that we have satisfactory title to all of our material properties. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business.

Hydraulic Fracturing

Hydraulic fracturing has been a routine part of the completion process for the majority of the wells on our producing properties in Oklahoma, Colorado and Texas for several decades. Most of our properties are dependent on our ability to hydraulically fracture the producing formations. We are currently conducting hydraulic fracturing activities in our Northeastern Oklahoma and Southern Oklahoma core areas. The majority of our leasehold acreage is currently held by production from existing wells. Therefore, fracturing is not currently required to maintain this acreage but it will be required in the future to develop the majority of our proved behind pipe and proved undeveloped reserves associated with this acreage. Nearly all of our proved behind pipe and proved undeveloped reserves associated with future drilling and recompletion projects, or 36% of our total estimated proved reserves as of December 31, 2015 will be subject to hydraulic fracturing. Although the cost of each well will vary, on average approximately 9% of the total cost of drilling and completing a well is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completing our wells are treated and are built into and funded through our normal capital expenditure budget.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please see "Environmental Matters and Regulation —Water Discharges" in this section. For related risks to our unitholders, please see "Item 1A. Risk Factors — Risks Related to Our Business." Federal and State legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Insurance

In accordance with industry practice, we maintain insurance against many potential operating risks to which our business could be exposed. Our coverage includes general liability, commercial umbrella liability, control of well, auto liability, property and equipment, worker's compensation and employer's liability, and directors and officers liability.

Currently, we have coverage for general liability insurance coverage, which includes coverage for sudden and accidental pollution liability and legal and contractual liabilities arising out of property damage and bodily injury, among other things. The insurance policies contain maximum policy limits and in most cases, deductibles that must be met prior to recovery and are subject to certain customary exclusions and limitations. This insurance coverage is in addition to the general and automobile liability policies and may be triggered if the general or automobile liability insurance policy limits are exceeded and exhausted. The control of well policy insures us for blowout risks associated with drilling, completing and operating our wells, including above ground pollution.

These policies do not provide coverage for all liabilities, and no assurance can be given that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, tribal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) govern the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil drilling and production activities; (iii) restrict the way we handle or dispose of our wastes; (iv) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (v) require investigatory and remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (vi) impose obligations to reclaim and abandon wellsites. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of corrective or remedial obligations, and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the U.S. Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, storage, transport, drilling, disposal, and remediation requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storages, transport, drilling disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot provide assurances that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, we can provide no assurance that we will not incur substantial costs in the future related to revised or additional environmental regulations that could have a material adverse effect on our business, financial condition and results of operations.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The federal Resource Conservation and Recovery Act, as amended, ("RCRA"), and comparable state statutes and their respective implementing regulations, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil, if properly handled, are exempt from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. However, it is possible that certain oil exploration, development and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to public health or the environment and to seek to recover from responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances or other pollutants released into the environment. Despite the so-called petroleum exclusion, we generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease, or operate numerous properties that have been used for oil and/or natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Water Discharges

The federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and analogous state laws, impose restrictions and strict controls regarding the discharge of pollutants, including oil and hazardous substances, into state waters and federal navigable waters in the United States. The discharge of pollutants into federal or state waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state or tribal agency that has been delegated authority for the program by the EPA. Federal, state and tribal regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. Plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws required individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Oil Pollution Act of 1990, as amended ("OPA"), amends the Clean Water Act and establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the United States

The Safe Drinking Water Act, as amended, (the "SDWA") and analogous state laws impose requirements relating to our underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations related to permitting, testing, monitoring, record-keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water. We currently own and operate a number of injection wells, used primarily for reinjection of produced waters that are subject to SDWA requirements.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We employ conventional hydraulic fracturing techniques to increase the productivity of certain of our properties. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into rock formations to fracture the surrounding rock and stimulate production. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has published draft guidance documents related to this newly asserted regulatory authority. In addition, Congress has considered federal regulation of hydraulic fracturing including disclosure of the chemicals used in the hydraulic fracturing process. Several states in which we operate including Texas and Oklahoma have adopted rules requiring the disclosure of certain information related to hydraulic fluids associated with horizontal wells that are hydraulically fractured. Additionally, some states and local governments have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. For example, the state of Arkansas established a moratorium on waste water injection in certain areas hydraulic fracturing activities due to concern that such activities may be related to increased earthquake activity. Other authorities are considering restrictions on the disposal of hydraulic fluids by deepwell injection. We follow applicable industry standard practices and legal requirements for groundwater protection in our hydraulic fracturing activities. In the event that new or more stringent federal, state or local legal restrictions are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and in June 2015 issued a draft report for public comment and peer review. The EPA is conducting a study regarding the disposal of wastewater resulting from hydraulic fracturing activities into surface water. In April 2015, the EPA published proposed pretreatment standards for oil and natural gas extraction. The U.S. Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Almost all of our hydraulic fracturing operations are conducted on vertical wells. The fracture treatments on these wells are much smaller and utilize much less water than what is typically used on most of the shale gas wells that are being drilled throughout the United States. We follow applicable industry standard practices and legal requirements for groundwater protection in our operations, subject to close supervision by state and federal regulators, which conduct many inspections during operations that include hydraulic fracturing. We minimize the use of water and dispose of the produced water into approved disposal or injection wells. We currently do not intentionally discharge water to the surface.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development of our projects.

While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe that such requirements will have a material adverse effect on our operations. For example, on August 16, 2012, the EPA published final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or "VOC", and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations that occurred at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could increase our costs of development and production, though we do not expect these requirements to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, or CO_2, methane, and other greenhouse gases, or "GHG", present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHG under existing provisions of the federal Clean Air Act. These regulations include requirements to regulate emissions of GHG from motor vehicles, certain requirements for construction and operating permit reviews for GHG emissions from certain large stationary sources, requiring the reporting of GHG emissions from specified large GHG emission sources including operators of onshore oil and natural gas production and rules requiring so-called green completions of natural gas wells for wells constructed after January 2015. In addition, pursuant to President Obama's strategy to reduce methane emissions, the EPA is expected to propose in spring of 2016 new regulations that will set methane emission standards for new and modified oil and natural gas facilities. We are currently monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule. Data collected from our initial GHG monitoring activities indicated that we do not currently exceed the threshold level of GHG emissions triggering a reporting obligation. To the extent we exceed the applicable regulatory threshold level in the future, we will report the emissions beginning in the applicable period. Also, Congress has from time to time considered legislation to reduce emissions of GHG and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHG. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require us to incur significant costs to reduce emissions of GHG associated with operations or could adversely affect demand for our production.

National Environmental Policy Act

Oil exploration, development and production activities on federal lands are subject to the National Environmental Policy Act, as amended, (“NEPA”). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that analyzes the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Currently, we have no exploration and production activities on federal lands. However, for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA may be required. This process has the potential to delay the development of oil projects.

Endangered Species Act

The federal Endangered Species Act (“ESA”) may restrict activities that affect endangered or threatened species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While our facilities are located in areas that are not currently designated as habitat for endangered or threatened species, the designation of previously unidentified endangered or threatened species habitats could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to consider listing more than 250 species as endangered under the Endangered Species Act over a period of six years. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, (“OSHA”), and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations, and similar state statutes and regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Other Regulation of the Oil and Natural Gas Industry

General

Various aspects of our oil and natural gas operations are subject to extensive and frequently changing regulation as the activities of the oil and natural gas industry often are reviewed by legislators and regulators. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members.

The Federal Energy Regulatory Commission (“FERC”) regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. FERC regulates interstate oil pipelines under the provisions of the Interstate Commerce Act ("ICA") as in effect in 1977 when ICA jurisdiction over oil pipelines was transferred to FERC, and the Energy Policy Act of 1992, or the EPA Act 1992. FERC is also authorized to prevent and sanction market manipulation in natural gas markets under the Energy Policy Act of 2005. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

In addition, the Federal Trade Commission (“FTC”), and the U.S. Commodity Futures Trading Commission (“CFTC”) hold statutory authority to prevent market manipulation in oil and energy futures markets, respectively. Together with FERC, these agencies have imposed broad rules and regulations prohibiting fraud and manipulation in oil and natural gas markets and energy futures markets. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation. Failure to comply with such market rules, regulations and requirements could have a material adverse effect on our business, results of operations, and financial condition.

Oil and NGLs Transportation Rates

Our sales of crude oil, condensate and NGLs are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the ICA and EPA act 1992. The price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for oil, NGLs, and other products are regulated by the FERC, and in general, these rates must be cost-based or based on rates in effect in 1992, although FERC has established an indexing system for such transportation which allows such pipelines to take an annual inflation-based rate increase. Shippers may, however, contest rates that do not reflect costs of service. The FERC has also established market-based rates and settlement rates as alternative forms of ratemaking in certain circumstances.

In other instances involving intrastate-only transportation of oil, NGLs, and other products, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. Such pipelines may be subject to regulation by state regulatory agencies with respect to safety, rates and/or terms and conditions of service, including requirements for ratable takes or non-discriminatory access to pipeline services. The basis for intrastate regulation and the degree of regulatory oversight and scrutiny given to intrastate pipelines varies from state to state. Many states operate on a complaint-based system and state commissions have generally not initiated investigations of the rates or practices of liquids pipelines in the absence of a complaint.

Regulation of Oil and Natural Gas Exploration and Production

Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits, bonds and pollution liability insurance for the drilling of wells, regulating the location of wells, the method of drilling, casing, operating, plugging and abandoning wells, notice to surface owners and other third parties, and governing the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation of oil and natural gas resources, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing of such wells.

Oklahoma allows forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil wells generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil we can produce from our wells or limit the number of wells or the locations at which we can drill.

States also impose severance taxes and enforce requirements for obtaining drilling permits. For example, the State of Oklahoma currently imposes a production tax and an excise tax for oil and natural gas properties. A portion of our wells in Oklahoma currently receive a reduced production tax rate due to the Enhanced Recovery Project Gross Production Tax Exemption. Additionally, production tax rates vary by state. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future.

In 2012, there were numerous new and proposed regulations related to oil and natural gas exploration and production activities. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Pipeline Safety

While we do not own pipelines subject to safety regulation, we rely on such pipelines to deliver our production. Federal and state safety regulations have become increasingly more stringent over time and could affect the availability and cost of pipeline transportation to us.

Employees

The officers of our general partner manage our operations and activities. Neither we, our subsidiaries, nor our general partner have employees. Our general partner has entered into a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating will perform services for us, including the operation of our properties. Mid-Con Energy Operating has over 90 employees performing services for our operations and activities. We believe that Mid-Con Energy Operating has a satisfactory relationship with these employees.

Offices

In addition to our oil and natural gas properties discussed above, we lease corporate office space in Dallas, Texas and Tulsa, Oklahoma, and we also maintain a number of field office locations. We believe that our existing office facilities are adequate to meet our needs for the immediate future.

Financial Information

We operate our business as a single segment. Additionally, all of our properties are located in the United States and all of the related reserves are derived from properties located in the United States. Our financial information is included in the consolidated financial statements and the related notes included in "Item 8. Financial Statements and Supplementary Data."

Available Information

Our annual reports on Form 10–K, quarterly reports on Form 10–Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are made available free of charge on our website at www.midconenergypartners.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. These documents are also available on the SEC's website at www.sec.gov or you may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. No information from either the SEC's website or our website is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. This list is not exhaustive.

Risks Related to Our Business

We may not have sufficient cash available to make quarterly distributions on our units following the establishment of cash reserves and payment of expenses, including payments to our general partner.

We may not have sufficient cash available for distribution each quarter to make quarterly distributions on our units. Under the terms of our partnership agreement, the amount of cash available for distributions will be reduced by our operating expenses and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including development of our oil and natural gas properties, future debt service requirements and future cash distributions to our unitholders. The amount of cash that we distribute to our unitholders will depend principally on the cash we generate from operations, which will depend 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 inclusive of the net revenues from realized hedges;
- the amount and timing of settlements on our commodity derivative contracts;
- the ability to acquire additional oil and natural gas properties on economically acceptable terms;
- the ability to continue our development projects at economically attractive costs;
- the level of our capital expenditures, including scheduled and unexpected maintenance expenditures;
- the level of our operating costs, including payments to our general partner; and
- the level of our interest expense, which depends on the amount of our outstanding indebtedness and the interest payable thereon.

We may not make cash distributions during periods when we record net income.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flows, including cash from reserves established by our general partner and borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions to our unitholders during periods when we record net losses and may not make cash distributions to our unitholders during periods when we record net income.

If oil prices decline further or remain at current levels for a prolonged period, or if there is an increase in the differential between the NYMEX-WTI or other benchmark prices of oil and the wellhead price we receive for our production, our cash flows from operations will decline, which could reduce the cash available for distribution.

Lower oil prices may decrease our revenues and therefore, our cash available for distribution to our unitholders. Prices for oil may fluctuate widely in response to relatively minor changes in supply of and demand for oil, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil;
- market expectations about future prices of oil;
- the price and quantity of imports of crude oil;

- overall domestic and global economic conditions;
- political and economic conditions in other oil producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- trading in oil derivative contracts;
- the level of consumer product demand;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the proximity, cost, availability and capacity of oil pipelines and other transportation facilities;
- the impact of the U.S. dollar exchange rates on oil prices; and
- the price and availability of alternative fuels.

Historically, oil prices have been extremely volatile. For the five years ended December 31, 2015, front-month NYMEX-WTI oil futures prices ranged from a high of $113.93 to a low of $34.73 per barrel. As of February 26, 2016, the front-month NYMEX-WTI oil futures price was $32.86 per barrel.

Also, the prices that we receive for our oil production often reflect a regional discount, based on the location of the production, to the relevant benchmark prices, such as the NYMEX-WTI, that are used for calculating hedge positions. These discounts, if significant, could similarly reduce our cash available for distribution to our unitholders and adversely affect our financial condition.

If commodity prices decline further or remain at current levels for a prolonged period, production from a significant portion of our producing or development projects may become uneconomic and cause write downs of the value of our properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

If commodity prices decline further or remain at current levels for a prolonged period many of our producing or development projects may become uneconomic resulting in a downward adjustment of our reserve estimates, which could negatively impact our borrowing base under our current revolving credit facility and/or our ability to fund our operations or to pay distributions to our unitholders.

NYMEX-WTI oil prices have declined from $53.27 per barrel on December 31, 2014 to $37.04 per barrel on December 31, 2015. The reduction in price was caused by many factors, including substantial increases in U.S. production and reserves from unconventional (shale) reservoirs, without an offsetting increase in demand. The International Energy Agency forecasts a decline U.S. production and a slowdown in global demand growth in 2016. This environment could cause the prices for oil to remain at current levels or fall to lower levels.

The decrease in commodity prices during 2015 resulted in a downward adjustment to our estimated proved reserves for our properties and our standardized measure which decreased from approximately $664.3 million as of December 31, 2014 to $191.4 million as of December 31, 2015. Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil and natural gas properties. We recognized approximately $103.9 million in non-cash impairment expense for the year ended December 31, 2015. In addition, if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil properties for additional impairments. We may incur impairment charges in the future which could have a material adverse effect on our results of operations in the period taken.

Our hedging strategy may be ineffective in mitigating the impact of commodity price volatility on our cash flows, which could result in financial losses or could reduce cash available for distribution.

Our hedging strategy is to enter into commodity derivative contracts covering a portion of our near-term estimated oil production. The prices at which we are able to enter into commodity derivative contracts covering our production in the future will be dependent upon oil futures prices at the time we enter into these transactions, which may be substantially higher or lower than current oil prices.

Our revolving credit facility prohibits us from entering into commodity derivative contracts covering all of our estimated future production, and we therefore retain the risk of a price decrease on our volumes which we are precluded from securing with commodity derivative contracts. Furthermore, we may be unable to enter into additional commodity derivative contracts during favorable market conditions and, thus, may be unable to lock in attractive future prices for our product sales. Finally, our revolving credit facility and associated amendments may cause us to enter into commodity derivative contracts at inopportune times.

Our hedging activities could result in cash losses and may limit the prices we would otherwise realize for our production, which could reduce our cash available for distribution.

Our hedging strategy may limit our ability to realize cash flows from commodity price increases. Many of our commodity derivative contracts require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays), we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity and our cash available for distribution to our unitholders.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a commodity derivative contract. Disruptions in the financial markets could lead to a sudden decrease in a counterparty's liquidity, which could impair its ability to perform under the terms of the commodity derivative contract and, accordingly, prevent us from realizing the benefit of the commodity derivative contract. Because we conduct our hedging activities exclusively with participants in our revolving credit facility, our net position on a counterparty by counterparty basis is generally that of a borrower.

Unless we replace the oil reserves we produce, our revenues and production will decline, which would adversely affect our cash flows from operations and our ability to make distributions to our unitholders.

We may be unable to make quarterly distributions without substantial capital expenditures that maintain our asset base. Producing oil reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil reserves and production and, therefore, our cash flows and ability to make distributions are highly dependent on our success in economically finding or acquiring recoverable reserves and efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations and reduce cash available for distribution to our unitholders.

Our operations require substantial capital expenditures, which will reduce our cash available for distribution and could materially affect our ability to make distributions to our unitholders.

We make and expect to continue to make substantial capital expenditures for the development, production and acquisition of oil reserves. Some of these expenditures will reduce our cash available for distribution. If the borrowing base under our revolving credit facility or our revenues decrease as a result of lower oil prices, declines in estimated reserves or production or for any other reason, we may not be able to obtain the capital necessary to sustain our operations at a level necessary to make distributions to our unitholders. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our development projects, which in turn could lead to a decline in our oil reserves, and could adversely affect our business, financial condition and results of operations and reduce cash available for distribution to our unitholders.

Developing and producing oil is a costly and high-risk activity with many uncertainties that could adversely affect our business, financial condition or results of operations and, as a result, our ability to make distributions to our unitholders.

The cost of developing and operating oil properties, particularly under a waterflood, is often uncertain, and cost and timing factors can adversely affect the economics of a well. Our efforts may be uneconomical if we drill dry holes, or if our properties are productive but do not produce as much oil as we had estimated. Furthermore, our producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of equipment, labor or other services;
- unexpected operational events and conditions;
- adverse weather conditions and natural disasters;
- injection plant or other facility or equipment malfunctions and equipment failures or accidents;
- title disputes;
- unitization difficulties;
- pipe or cement failures, casing collapses or other downhole failures;
- compliance with environmental and other governmental requirements;
- lost or damaged oilfield service tools;

- unusual or unexpected geological formations and reservoir pressure;
- loss of injection fluid circulation;
- costs or delays imposed by or resulting from compliance with regulatory requirements;
- fires, blowouts, surface craterings, explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations; and
- uncontrollable flows of oil or well fluids.

If any of these factors were to occur with respect to a particular property, we could lose all or a part of our investment in the property, or we could fail to realize the expected benefits from the property, either of which could materially and adversely affect our revenue and cash available for distribution to our unitholders.

We inject water into most of our properties to maintain and, in some instances, to increase the production of oil. We may in the future employ other secondary or tertiary recovery methods in our operations. The additional production and reserves attributable to the use of secondary recovery methods and of tertiary recovery methods are inherently difficult to predict. If our recovery methods do not result in expected production levels, we may not realize an acceptable return on the investments we make to use such methods.

Hydraulic fracturing has been a part of the completion process for the majority of the wells on our producing properties, and most of our properties are dependent on our ability to hydraulically fracture the producing formations. We engage third-party contractors to provide hydraulic fracturing services and generally enter into service orders on a job-by-job basis. Some service orders limit the liability of these contractors. Hydraulic fracturing operations can result in surface spillage or, in rare cases, the underground migration of fracturing fluids. Any such spillage or migration could result in litigation, government fines and penalties or remediation or restoration obligations. Our current insurance policies provide some coverage for losses arising out of our hydraulic fracturing operations. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated clean-up activities, and total losses related to a spill or migration could exceed our per occurrence or aggregate policy limits. Any losses due to hydraulic fracturing that are not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our estimated proved reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

It is not possible to measure underground accumulations of oil in an exact way. Oil reserve engineering is complex, requiring subjective estimates of underground accumulations of oil and assumptions concerning future oil prices, future production levels and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may prove inaccurate. For example, if the price used in our December 2015 reserve report had been $10.00 less per barrel for oil, then the standardized measure of our estimated proved reserves as of that date would have decreased from $191.4 million to $93.3 million.

Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could affect our business, results of operations and financial condition and our ability to make distributions to our unitholders.

The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil reserves.

The present value of future net cash flows from our proved reserves, or standardized measure, may not represent the current market value of our estimated proved oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our estimated proved reserves on the 12-month average oil index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with the Financial Accounting Standard Board Codification 932, “Extractive Activities-Oil and Gas,” may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

If we do not make acquisitions on economically acceptable terms, our future growth and ability to make or increase distributions will be limited.

Our ability to make and to increase distributions to our unitholders depends in part on our ability to make acquisitions that result in an increase in available cash per unit. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with their owners;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to acquire properties containing estimated proved reserves, our total level of estimated proved reserves will decline as a result of our production, and we will be limited in our ability to make cash distributions to our unitholders.

Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil reserves. Even if we make acquisitions that we believe will increase available cash per unit, these acquisitions may nevertheless result in a decrease in available cash per unit. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, commodity prices, revenues, operating expenses and costs;
- an inability to successfully integrate the assets we acquire;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing assets; and
- the occurrence of other significant charges, such as the impairment of oil properties, goodwill or other intangible assets, asset devaluations or restructuring charges.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of properties acquired from third parties (as opposed to the Mid-Con Affiliate) may be incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition, given the time constraints imposed by most sellers. Even a detailed review of the properties owned by third parties and the records associated with such properties may not reveal existing or potential problems, nor will such a review permit us to become sufficiently familiar with such properties to assess fully the deficiencies and potential issues associated with such properties. We may not always be able to inspect every well on properties owned by third parties, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Adverse developments in our core areas would reduce our ability to make distributions to our unitholders.

We only own oil and natural gas properties and related assets, all of which are currently located in Oklahoma, Colorado, and Texas. An adverse development in the oil and natural gas business in these geographic areas could have an impact on our results of operations and cash available for distribution to our unitholders.

We are primarily dependent upon a small number of customers for our production sales and we may experience a temporary decline in revenues and production if we lose any of those customers.

The loss of any of our customers could temporarily delay production and sale of our oil and natural gas. If we were to lose any of our significant customers, we believe that we could identify substitute customers to purchase the impacted production volumes. However, if any of our customers dramatically decreased or ceased purchasing oil from us, we may have difficulty finding substitute customers to purchase our production volumes at comparable rates.

Sales of oil and natural gas to BML, Enterprise and Coffeyville accounted for approximately 31%, 22% and 21%, respectively, of our sales for the year ended December 31, 2015. Our production is and will continue to be marketed by our affiliate, Mid-Con Energy Operating. By selling a substantial majority of our current production to a small concentration of customers we believe that we have obtained and will continue to receive more favorable pricing than would otherwise be available to us if smaller amounts had been sold to several purchasers based on posted prices. To the extent these significant customers reduce the volume of oil they purchase from us, we could experience a temporary interruption in sales of, or may receive a lower price for, our oil production, and our revenues and cash available for distribution could decline which could adversely affect our ability to make cash distributions to our unitholders.

In addition, a failure by any of these significant customers, or any purchasers of our production, to perform their payment obligations to us could have a material adverse effect on our results of operations. To the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to us. If for any reason we were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of our production were uncollectible, we would recognize a charge in the earnings of that period for the probable loss and could suffer a material reduction in our liquidity and ability to make distributions to our unitholders.

Unitization difficulties may prevent us from developing certain properties or greatly increase the cost of their development.

Regulation of waterflood unit formation is typically governed by state law. In Oklahoma, 63% of the leasehold and mineral owners in a proposed unit area must consent to a unitization plan before the Oklahoma Corporation Commission, the regulatory body which oversees issues related to unitization and well spacing, will issue a unitization order. Mid-Con Energy Operating may be required to dedicate significant amounts of time and financial resources to obtaining consents from other owners and the necessary approvals from the Oklahoma Corporation Commission and similar regulatory agencies in other states. Obtaining these consents and approvals may also delay our ability to begin developing our new waterflood projects and may prevent us from developing our properties in the way we desire.

Other owners of mineral rights may object to our waterfloods.

It is difficult to predict the movement of the injection fluids that we use in connection with waterflooding. It is possible that certain of these fluids may migrate out of our areas of operations and into neighboring properties, including properties whose mineral rights owners have not consented to participate in our operations. This may result in litigation in which the owners of these neighboring properties may allege, among other things, a trespass and may seek monetary damages and possibly injunctive relief, which could delay or even permanently halt our development of certain of our oil properties.

We might be unable to compete effectively with larger companies, which might adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with companies that possess and employ financial, technical and personnel resources substantially greater than ours. These companies may be able to pay more for properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities despite the recent declines in oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations and our ability to make distributions to our unitholders.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests lying contiguous or adjacent to or adjoining our interests could take actions, such as drilling additional wells, that could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves, and may inhibit our ability to further exploit and develop our reserves.

We may incur additional debt to enable us to pay our quarterly distributions, which may negatively affect our ability to pay future distributions or execute our business plan.

In October 2015, our Board of Directors elected to suspend quarterly cash distributions on our common units. The terms of our credit agreement require the pre-approval of our lenders in order to reinstate distributions on our common units, however in the case whereby our distributions were to be reinstated, we may from that point forward be unable to make future distributions without borrowing under our revolving credit facility. If we were to use borrowings under our revolving credit facility to pay distributions to our unitholders for an extended period of time rather than to fund capital expenditures and other activities relating to our operations, we may be unable to maintain or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on our future indebtedness to pay these distributions, would reduce our cash available to make distributions on our units and could have a material adverse effect on our business, financial condition and results of operations.

Our revolving credit facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

Our revolving credit facility restricts, among other things, our ability to incur debt and pay distributions under certain circumstances, and requires us to comply with customary financial covenants and specified financial ratios. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our revolving credit facility that are not cured or waived within specific time periods, a significant portion of our indebtedness may become immediately due and payable, we could be prohibited from making distributions to our unitholders, and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our revolving credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our revolving credit facility, the lenders could seek to foreclose on our assets.

The total amount we are able to borrow under our revolving credit facility is limited by a borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts, as determined by our lenders in their sole discretion. The borrowing base is subject to redetermination on a semi-annual basis and more frequent redetermination in certain circumstances. In November 2015, our borrowing base was reduced from $220.0 million to $190.0 million, consisting of a $165.0 million conforming tranche which requires monthly commitment reductions of $2.5 million each month through May 2016, and a $25.0 million non-conforming tranche. The redetermination also included an amendment requiring consent by our lenders in order to make cash distributions to our unitholders. If our lenders were to decrease our borrowing base to a level below our then outstanding borrowings, which as of February 29, 2016 were $173.0 million, the amount exceeding the revised borrowing base would become immediately due and payable. The negative redetermination of our borrowing base could adversely affect our business, results of operations, financial condition and our ability to make distributions to our unitholders. Furthermore, in the future, we may be unable to access sufficient capital under our revolving credit facility as a result of any decrease in our borrowing base.

We may not be able to generate enough cash flows to meet our debt obligations.

We expect our earnings and cash flows to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Additionally, our future cash flows may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flows from operations and to service our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flows from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot provide assurances that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flows to satisfy our debt obligations or to obtain alternative financing, could materially and adversely affect our ability to service our indebtedness and our business, financial condition and results of operations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in the exploration, development and production of our oil and natural gas properties, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of our wells and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets due to weather and adverse economic conditions have made it more difficult for us to obtain certain types of coverage. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and we cannot be sure the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and under-insured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to our unitholders.

Our business depends in part on transportation, pipelines and refining facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our production and could harm our business.

The marketability of our production depends in part on the availability, proximity and capacity of pipelines, tanker trucks and other transportation methods, and refining facilities owned by third parties. The amount of oil that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of available capacity on such systems, tanker truck availability and extreme weather conditions. Also, the shipment of our oil on third party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or refining facility capacity could reduce our ability to market our oil production and harm our business. Our access to transportation options and the prices we receive for our production can also be affected by federal and state regulation, including regulation of oil production and transportation, and pipeline safety, as well by general economic conditions and changes in supply and demand. In addition, the third parties on whom we rely for transportation services are subject to complex federal, state, tribal and local laws that could adversely affect the cost, manner or feasibility of conducting our business.

Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHG present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHG under existing provisions of the federal Clean Air Act, including requirements to reduce emissions of GHG from motor vehicles, requirements associated with certain construction and operating permit reviews for GHG emissions from certain large stationary sources, reporting requirements for GHG emissions from specified large GHG emission sources, including certain owners and operators of onshore oil and natural gas production and rules requiring so-called green completions of natural gas wells constructed after January 2015. We are currently monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule. Data collected from our initial GHG monitoring activities indicated that we do not exceed the threshold level of GHG emissions triggering a reporting obligation. To the extent we exceed the applicable regulatory threshold level in the future, we will report the emissions beginning in the applicable period. Also, Congress has from time to time considered legislation to reduce emissions of GHG, and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHG. Pursuant to President Obama's strategy to reduce methane emissions, EPA is expected to propose in spring of 2016 new regulations that will set methane emission standards for new and modified oil and natural gas facilities. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require us to incur significant costs to reduce emissions of GHG associated with operations or could adversely affect demand for our production.

Rules recently finalized regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for

Hazardous Air Pollutants ("NESHAP") programs. The EPA's final rule includes NSPS standards for completions of hydraulically fractured wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The new rules became effective October 15, 2012; however, a number of the requirements did not take immediate effect. The final rule establishes a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. During the first phase, ended December 31, 2014, owners and operators must either flare their emissions or use emissions reduction technology called "green completions" technologies already deployed at wells. On or after January 1, 2015, all newly fractured wells were required to use green completions. Controls for certain storage vessels and pneumatic controllers may phase-in over one year beginning on August 16, 2012, which is the date the final rule was published in the Federal Register, while certain compressors, dehydrators and other equipment must comply with the final rule immediately or up to three years and 60 days after publication of the final rule, depending on the construction date and/or nature of the unit. We continue to evaluate the EPA's final rule, as it may require changes to our operations, including the installation of new emissions control equipment.

Our operations are subject to environmental and operational safety laws and regulations that may expose us to significant costs and liabilities.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil development and production activities. These costs and liabilities could arise under a wide range of federal, state, tribal and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. Claims for damages to persons or property from private parties and governmental authorities may result from environmental and other impacts of our operations.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to make cash distributions to our unitholders could be adversely affected. For a detailed discussion please read "Item 1. Business —Environmental Matters and Regulation."

The derivatives regulation provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act and related rules adopted and to be adopted could adversely affect our ability to use commodity derivative contracts to reduce the effect of commodity price and other risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Pursuant to the Act, the Commodities Futures Trading Commission (the "CFTC"), the SEC and other regulators have promulgated and continue to promulgate rules implementing the Act's derivative regulation provisions. The Act and the CFTC rules will require us, in connection with certain derivatives activities, to comply with mandatory clearing and exchange-trading requirements (or take steps to qualify for an exemption to such requirements) with respect to swap contracts we enter that fall within a class of swap contracts the CFTC has designed for mandatory clearing. Although we expect to qualify for the "end-user exception" to the mandatory clearing and exchange-trading requirements for the swap contracts we enter to hedge our commercial risks, these mandatory clearing and exchange-trading requirements apply to other market participants, such as our counterparties (who may be registered as swap dealers), and the application of those requirements to such persons may change the cost and availability of the swap contracts we use to hedge our commercial risks. As of February 29, 2016, the CFTC had only designated certain classes of interest rate swap contracts and index credit default swap contracts for mandatory clearing, and it is unclear when the CFTC will designate other classes of swap contracts, such as physical commodity swap contracts, for mandatory clearing. The CFTC has proposed position limits rules that sets limits on the positions in certain core futures and futures equivalent swap contracts, option contracts and swap contracts for or linked to certain physical commodities that market participants could hold at any time, subject to with exceptions for certain bona fide hedging transactions intended to hedge certain price risks and certain other exemptions. Other rules also remain to be finalized by the CFTC, and, as a result, it is not possible at this time to predict with certainty the full effects of the Act and the related rules on us and the timing of such effects. A rule adopted under the Act has caused certain market participants and may cause other market participants, including certain of the historical counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities. Those separate entities could be our counterparties in future swap contracts and may not be as creditworthy as our current counterparties. The Act and the rules adopted thereunder may significantly increase the cost of entering into and maintaining commodity derivative contracts (including to comply with swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of commodity derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Act and the related rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, liquidity and cash flows and our ability to make distributions to our unitholders.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used in the completion of unconventional wells in shale formations as well as tight conventional formations, including many of those that we complete and produce. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has published draft guidance documents. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Many states in which we operate have adopted rules requiring well operators to publicly disclose certain information regarding hydraulic fracturing operations, including the chemical composition of any liquids used in the hydraulic fracturing process. Generally, certain proprietary information may be excluded from an operator’s disclosure. Additionally, some states and local authorities have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. In the event that new or more stringent federal, state or local legal restrictions are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in our development or production activities.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, and published an update on December 21, 2012. The EPA issued a draft report for public comment and peer review in June 2015. Moreover, the EPA is conducting a study regarding wastewater resulting from hydraulic fracturing activities. In April 2015, the EPA published proposed pretreatment standards for oil and gas extraction. On April 13, 2012, the Department of Interior, the Department of Energy and the EPA issued a memorandum outlining a multi-agency collaboration on unconventional oil and natural gas research in response to the White House “Blueprint for a Secure Energy Future” and the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas. On September 5, 2012, the U.S. Government Accountability Office issued two reports concerning environmental and health risks and key environmental and public health requirements related to hydraulic fracturing but did not make any recommendations. More recently there have been reports linking the injection of produced fluids from hydraulic fracturing to earthquakes. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms. Any additional level of regulation could lead to operational delays or increased operating costs which could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and would increase our costs of doing business, resulting in a decrease of cash available for distributions to our unitholders.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may affect adversely our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations sectors, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our business. In addition, cyber attacks on our customer and employee data may result in a financial loss and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

Risks Inherent in an Investment in Us

Our general partner controls us, and the Founders, our Mid-Con Affiliate and Yorktown own an approximate 18.8% interest in us. They have conflicts of interest with, and owe limited fiduciary duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Our general partner has control over all decisions related to our operations. Our general partner is owned by the Founders. As of December 31, 2015, the Founders, our Mid-Con Affiliate and Yorktown own an approximate 18.8% interest in us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners. All of the executive officers and non-independent directors of our general partner are also officers and/or directors of the Mid-Con Affiliate and will continue to have economic interests in, as well as management and fiduciary duties to, the Mid-Con Affiliate. Additionally, one of the directors of our general partner is a principal with Yorktown. As a result of these relationships, conflicts of interest may arise in the future between the Mid-Con Affiliate and Yorktown and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our limited partner unitholders. These potential conflicts include, among others:

- Our partnership agreement limits our general partner's liability, reduces its fiduciary duties and also restricts the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are consenting to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- Neither our partnership agreement nor any other agreement requires the Mid-Con Affiliate and Yorktown or their respective affiliates (other than our general partner) to pursue a business strategy that favors us. The officers and directors of the Mid-Con Affiliate and Yorktown and their respective affiliates (other than our general partner) have a fiduciary duty to make these decisions in the best interests of their respective equity holders, which may be contrary to our interests;
- The Mid-Con Affiliate and Yorktown and their affiliates are not limited in their ability to compete with us, including with respect to future acquisition opportunities, and are under no obligation to offer or sell assets to us;
- All of the executive officers of our general partner who provide services to us also devote a significant amount of time to the Mid-Con Affiliate and are compensated for those services rendered;
- Our general partner determines the amount and timing of our development operations and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other businesses with which our general partner is or may become affiliated, and cash reserves, each of which can affect the amount of cash that is distributed to unitholders;
- We entered into a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides management, administrative and operational services to us, and Mid-Con Energy Operating will also provide these services to the Mid-Con Affiliate;
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- Our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- Our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Neither we nor our general partner have any employees, and we rely solely on Mid-Con Energy Operating to manage and operate our business. The management team of Mid-Con Energy Operating, which includes the individuals who manage us, also provides substantially similar services to the Mid-Con Affiliate, and thus is not solely focused on our business.

Neither we nor our general partner have any employees, and we rely solely on Mid-Con Energy Operating to provide management, administrative and operational services to us. Mid-Con Energy Operating provides substantially similar services and personnel to the Mid-Con Affiliate and, as a result, may not have sufficient human, technical and other resources to provide those services at a level that it would be able to provide to us if it did not provide similar services to these other entities. Additionally, Mid-Con Energy Operating may make internal decisions on how to allocate its available resources and expertise that may not always be in our best interest compared to those of the Mid-Con Affiliate or other affiliates of our general partner. There is no requirement that Mid-Con Energy Operating favor us over these other entities in providing its services. If the employees of Mid-Con Energy Operating do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make distributions to our unitholders may be reduced.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity and incur debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. In addition, as with other yield-oriented securities, our unit price is impacted by the level of cash distributions to unitholders and implied distribution yield. This implied distribution yield is often used by investors to compare and rank similar yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity or incur debt.

Public unitholders do not have a priority right to receive distributions and are not entitled to receive any payments of arrearages.

Unlike many publicly traded partnerships, we do not have any incentive distribution rights or subordinated units. Because there are no subordinated units, our public unitholders are not senior in payment of distributions over any other parties, including the Founders or Yorktown. Public unitholders will not have any right to receive any payments of distribution arrearages in future periods.

Units held by persons who our general partner determines are not eligible holders will be subject to redemption.

To comply with U.S. laws with respect to the ownership of interests in oil and natural gas leases on federal lands, we have adopted certain requirements regarding those investors who may own our common units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and natural gas leases on federal lands. As of the date hereof, Eligible Holder means:

- a citizen of the United States;
- a corporation organized under the laws of the United States or of any state thereof;
- a public body, including a municipality;
- an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof; or
- a limited partner whose nationality, citizenship or other related status would not, in the determination of our general partner, create a substantial risk of cancellation or forfeiture of any property in which we or our subsidiary has an interest.

Onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof. Unitholders who are not persons or entities who meet the requirements to be an Eligible Holder run the risk of having their common units redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Our unitholders have limited voting rights and are not entitled to elect our general partner or its Board of Directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders have no right on an annual or ongoing basis to elect our general partner or its Board of Directors. The Board of Directors of our general partner, including the independent directors, is chosen entirely by the Founders, as a result of their ownership of our general partner, and not by our unitholders. Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if our unitholders are dissatisfied, it would be difficult to remove our general partner without its consent.

The vote of the holders of at least 66.67% of all outstanding units is required to remove our general partner. As of December 31, 2015, the Founders, our Mid-Con Affiliate and Yorktown own an approximate 18.8% interest in us, which will enable those holders, collectively, to make it difficult to remove our general partner.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the Founders from transferring all or a portion of their ownership interests in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board of Directors and officers of our general partner with their own choices and thereby influence the decisions made by the Board of Directors and officers in a manner that may not be aligned with the interests of our unitholders.

We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval, which would dilute unitholders' ownership interests.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

Our partnership agreement restricts the limited voting rights of unitholders, other than Yorktown, our general partner and its affiliates, owning 20% or more of our common units, which may limit the ability of significant unitholders to influence the manner or direction of management.

Our partnership agreement restricts unitholders' limited voting rights by providing that any common units held by a person, entity or group owning 20% or more of any class of common units then outstanding, other than Yorktown, our general partner, its affiliates, their transferees and persons who acquired such common units with the prior approval of the Board of Directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting unitholders' ability to influence the manner or direction of management.

Sales of our common units by the selling unitholders may cause our price to decline.

As of December 31, 2015, the Founders, our Mid-Con Affiliate and Yorktown own 5,288,828 common units and 360,000 units held by our general partner, or an approximate 18.8% interest in us. Sales of these units or of other substantial amounts of our common units in the public market, or the perception that these sales may occur, could cause the market price of our common units to decline. Sales of such units could also impair our ability to raise capital through the sale of additional common units.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for our obligations as if it was a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Our unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make distributions to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to us that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our partnership agreement requires that we distribute all of our available cash (as defined in our partnership agreement), which could limit our ability to grow our reserves and production and make acquisitions.

Our partnership agreement provides that we will distribute all of our available cash each quarter. As a result, we may be dependent on the issuance of additional common units and other partnership securities and borrowings to finance our growth. A number of factors will affect our ability to issue securities and borrow money to finance growth, as well as the costs of such financings, including:

- general economic and market conditions, including interest rates prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and gas industry;
- the market price of, and demand for, our common units;
- our results of operations and financial condition; and
- prices for oil and natural gas.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions, or growth capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to make or increase our per unit distribution level. There are no limitations in our partnership agreement or in our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service ("IRS") were to treat us as a corporation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement, or a change in current law, could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions to unitholders would generally be taxed again as corporate distributions which would be taxable as dividends for U.S. federal income tax purposes to the extent paid out of our current or accumulated earnings and profits as determined for U.S. federal income tax purposes, and no income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders and, therefore, negatively impact the value of an investment in our units.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time the U.S. President and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would affect publicly traded partnerships. Further, the U.S. Treasury Department and the IRS have issued proposed regulations interpreting the scope of the qualifying income requirement for publicly traded partnerships by providing industry-specific guidance with respect to activities that will generate qualifying income. The proposed regulations, once issued in final form, may change interpretations of the current law relating to the characterization of income as qualifying income and could modify the amount of our gross income we are able to treat as qualifying income for purposes of the qualifying income requirement. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

The Obama Administration's budget proposal for fiscal year 2017 includes proposals that would, among other things, eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

If the IRS contests any of the federal income tax positions we take, the market for our units may be adversely affected, and the costs of any IRS contest will reduce our cash available for distribution to our unitholders.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may not agree with those positions. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Recently enacted legislation, applicable to partnership tax years beginning after 2017, alters the procedures for auditing large partnerships and for assessing and collecting taxes due (including penalties and interest) as a result of a partnership-level federal income tax audit. Under the new rules, unless we are eligible to, and do, elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to pay taxes, penalties and interest as a result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited tax year.

Our unitholders are required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us .

Because our unitholders are treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, our unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of our units could be more or less than expected .

If our unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and their adjusted tax basis in their units. Because prior distributions in excess of their allocable share of our total net taxable income decrease their tax basis in their units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation, depletion, amortization and Intangible Drilling Costs deduction recapture. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts, ("IRAs"), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Prospective unitholders who are tax-exempt entities or non-U.S. persons should consult their tax advisor before investing in our units.

We will treat each purchaser of units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of units and because of other reasons, we will adopt depreciation, depletion and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of units and could have a negative impact on the value of our units or result in audits of and adjustments to a unitholder's tax return.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Although recently issued final Treasury Regulations allow publicly traded partnerships to use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, these regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were issued, we may be required to change our method of allocating items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to affect a short sale of units may be considered as having disposed of those units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to effect a short sale of units may be considered as having disposed of the loaned units, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates ourselves using a methodology based on the market value of our units as a means to determine the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of units and could have a negative impact on the value of the units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. While we would continue our existence as a Delaware limited partnership, our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if special relief from the IRS is not available) for one fiscal year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. A technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a technical termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the tax year in which the termination occurs.

As a result of investing in our units, our unitholders may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future even if such unitholders do not live in those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own property and conduct business in many states, some of which impose a personal income tax on individuals and impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. We may own property or conduct business in other states or foreign countries in the future. It is a unitholder's responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in "Item 1. Business —Our Areas of Operation, —Our Oil and Natural Gas Reserve and Production" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Results of Operations" contained herein.

ITEM 3. 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. No amounts have been accrued at December 31, 2015.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are traded on the NASDAQ Global Select Market under the symbol "MCEP." At the close of business on February 29, 2016 , based upon information received from our transfer agent and brokers and nominees, we had 36 limited partner unitholders of record. This number does not include owners for whom common units may be held in "street" names. The daily high and low sales prices per common unit for the period from January 1, 2015 through December 31, 2015 were $7.21 and $1.05, respectively.

The following table sets forth the range of the daily high and low sales prices per common unit and cash distributions to limited partner unitholders for 2014 and 2015:

	Price Range		Cash Distribution
	High	Low	per Common Unit
2014:			
First Quarter	$ 24.15	$ 21.55	$ 0.515
Second Quarter	$ 23.36	$ 20.75	$ 0.515
Third Quarter	$ 24.39	$ 21.45	$ 0.515
Fourth Quarter	$ 22.25	$ 5.02	$ 0.125
2015:			
First Quarter	$ 7.21	$ 4.25	$ 0.125
Second Quarter	$ 6.97	$ 4.90	$ 0.125
Third Quarter	$ 4.99	$ 1.99	$ — (1)
Fourth Quarter	$ 3.53	$ 1.05	$ — (1)

(1) The Board of Directors of our general partner elected to suspend the third and fourth quarterly cash distributions that would have been paid in fourth quarter 2015 and first quarter of 2016.

Cash Distributions to Unitholders

Prolonged declines in commodity prices prompted us to suspend cash distributions to unitholders in an effort 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 future earnings, cash flows, capital requirements, financial conditions and other factors. Our credit agreement stipulates written consent from our lenders is required in order to reinstate distributions and also prohibits us from making cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining a future distributions.

Cash Distribution Policy

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The actual amount of our cash distributions for any quarter is subject to fluctuation based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement. However, there is no guarantee that we will pay quarterly distributions on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to reinstate distributions requires written consent from our lenders.

Definition of Available Cash

Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- *less* , the amount of cash reserves established by our general partner at the date of determination of available cash for the quarter to:
  - provide for the proper conduct of our business (including reserves for future capital expenditures, working capital and operating expenses) subsequent to that quarter;
  - comply with applicable laws, any of our loan agreements, security agreements, mortgage debt instruments or other agreements; or
  - provide funds for cash distributions to our unitholders (including our general partner) for any one or more of the next four quarters;
- *plus* , if our general partner so determines, all or a portion of cash or cash equivalents on hand on the date of determination of available cash for the quarter.

Securities Authorized for Issuance under Equity Compensation Plans

See “Item 11. Executive Compensation—Compensation Discussion and Analysis—Long-Term Incentive Program” for information regarding our equity compensation plans as of December 31, 2015.

Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

This section presents our selected historical consolidated financial data. The selected financial data is derived from our audited financial statements. The selected financial data should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 8. "Financial Statements and Supplementary Data,” both contained herein.

The following table shows selected financial data for the periods and as of the dates indicated (in thousands except number of units):

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Revenues:					
Oil sales	$ 72,520	$ 96,127	$ 85,080	$ 60,887	$ 36,813
Natural gas sales	1,394	784	656	674	1,218
Gain (loss) on derivatives, net	22,366	29,361	(5,675)	5,714	1,280
Total revenues	96,280	126,272	80,061	67,275	39,311
Operating costs and expenses:					
Lease operating expenses	33,591	26,091	16,366	10,948	8,491
Oil and natural gas production taxes	3,487	6,325	3,817	1,965	1,869
Impairment of proved oil and natural gas properties	103,938	30,206	1,578	1,296	—
Dry holes and abandonments of unproved properties	—	—	—	—	813
Depreciation, depletion and amortization	34,174	21,877	14,421	10,324	7,160
Accretion of discount on asset retirement obligations	432	250	173	126	78
General and administrative	9,411	14,313	12,244	11,000	3,767
Total operating costs and expenses	185,033	99,062	48,599	35,659	22,178
Income (loss) from operations	(88,753)	27,210	31,462	31,616	17,133
Other income (expense):					
Interest income and other	558	13	9	10	216
Interest expense	(7,258)	(4,731)	(3,282)	(1,764)	(578)
Loss on settlement of ARO	(42)	—	—	—	—
Gain on sale of assets	—	—	—	—	1,621
Other revenue and expenses, net	—	—	—	—	576
Total other income (expense)	(6,742)	(4,718)	(3,273)	(1,754)	1,835
Net income (loss)	$ (95,495)	$ 22,492	$ 28,189	$ 29,862	$ 18,968
Computation of net income (loss) per limited partner unit:					
General partner's interest in net income (loss)	$ (1,146)	$ 354	$ 518	$ 584	$ 379
Limited partners' interest in net income (loss)	$ (94,349)	$ 22,138	$ 27,671	$ 29,278	$ 18,589
Net income (loss) per limited partner unit:					
Basic	$ (3.18)	$ 0.98	$ 1.44	$ 1.62	$ 1.05
Diluted	$ (3.18)	$ 0.98	$ 1.44	$ 1.62	$ 1.05
Weighted average limited partner units outstanding:					
Limited partner units (basic)	29,642	22,499	19,234	18,049	17,640
Limited partner units (diluted)	29,642	22,518	19,249	18,049	17,640
Balance Sheet Data:					
Working capital	$ 1,308	$ 34,191	$ 1,435	$ 6,254	$ 2,361
Total assets	$ 327,086	$ 454,628	$ 190,083	$ 158,590	$ 96,611
Long-term debt	$ 150,000	$ 205,000	$ 112,000	$ 78,000	$ 45,000
Total equity	$ 130,498	$ 234,142	$ 66,788	$ 72,181	$ 43,349
Other Financial Data:					
Adjusted EBITDA	$ 54,982	$ 58,467	$ 59,973	$ 47,681	$ 23,994

Non-GAAP Financial Measures

We include in this report the non-GAAP financial measure Adjusted EBITDA and provide our calculation of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income and net cash from operating activities, which are the GAAP financial measurements most directly comparable to Adjusted EBITDA. We define Adjusted EBITDA as net income (loss) plus:

- Interest expense, net;
- Depreciation, depletion and amortization;
- Accretion of discount on asset retirement obligations;
- (Gain) loss on derivatives, net;
- Cash settlements received (paid) for matured derivatives, net;
- Cash settlements received (paid) for early termination and modification of derivatives, net;
- Deferred premiums (paid) upon settlement of derivatives,net;
- Cash premiums (paid) at inception of derivatives, net;
- Impairment of proved oil and natural gas properties;
- Dry holes and abandonments of unproved properties;
- Non-cash equity-based compensation; and
- (Gain) loss on sale of assets.

Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. We believe Adjusted EBITDA is useful to investors because it is used by our management, by external users of 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. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. Furthermore, Adjusted EBITDA should not be viewed as indicative of the actual amount of cash that is available for distributions or that is planned to be distributed for a given period nor does it equate to available cash as defined in our partnership agreement.

The following table presents our reconciliation of Adjusted EBITDA to Net income (loss), for each of the periods indicated. The table below further presents a reconciliation of Adjusted EBITDA to cash flow from operating activities, our most directly comparable GAAP financial measure, for each of the periods indicated.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Net income (loss)	$ (95,495)	$ 22,492	$ 28,189	$ 29,862	$ 18,968
Interest expense, net	7,248	4,718	3,273	1,754	362
Depreciation, depletion and amortization	34,174	21,877	14,421	10,324	7,160
Accretion of discount on asset retirement obligations	432	250	173	126	78
(Gain) loss on derivatives, net	(22,366)	(29,361)	5,675	(5,714)	(1,280)
Cash settlements received (paid) for matured derivatives, net	28,543	891	288	3,710	(2,157)
Cash settlements received for early termination and modification of derivatives, net	11,069	—	—	—	—
Deferred premiums paid upon settlement of derivatives, net	(1,701)	—	—	—	—
Cash premiums paid at inception of derivatives, net	(14,064)	—	—	—	—
Impairment of proved oil and natural gas properties	103,938	30,206	1,578	1,296	—
Dry holes and abandonments of unproved properties	—	—	—	—	813
Non-cash equity-based compensation	3,204	7,394	6,376	6,323	1,671
Gain on sale of assets	—	—	—	—	(1,621)
Adjusted EBITDA	$ 54,982	$ 58,467	$ 59,973	$ 47,681	$ 23,994

A reconciliation of Adjusted EBITDA to net cash provided by operating activities, our most directly comparable GAAP financial measure, for each of the periods indicated, is presented below:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Net cash provided by operating activities	$ 48,425	$ 50,464	$ 56,634	$ 47,717	$ 24,113
Debt issuance costs amortization	(1,156)	(348)	(168)	(131)	—
Change in working capital	425	3,633	234	(1,659)	(481)
Interest expense, net	7,248	4,718	3,273	1,754	362
Other	40	—	—	—	—
Adjusted EBITDA	$ 54,982	$ 58,467	$ 59,973	$ 47,681	$ 23,994

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with Item 8. "Financial Statements and Supplementary Data" contained herein.

Overview

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

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

As of December 31, 2015, our total estimated proved reserves were approximately 22.3 MMBoe, of which approximately 95% were oil and 68% were proved developed, both on a Boe basis. As of December 31, 2015, we operated approximately 100% of our properties through our affiliate, Mid-Con Energy Operating, and 67% of our properties were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended December 31, 2015 was approximately 4,676 Boe per day and our total estimated proved reserves had a reserve-to-production ratio of approximately 13 years.

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

Recent Developments

Operating Performance

We experienced a decline in revenue and operating income during 2015, as compared to 2014, as a result of lower oil and natural gas prices. During the year we delivered production growth of approximately 51%. On a per Boe basis, we reduced lease operating expenses approximately 15% and general and administrative costs by approximately 56%. Cash operating expenses declined approximately 26% year-over-year to average $28.72/Boe, with fourth quarter 2015 results averaging $27.90/Boe. From operating cash flows we repaid $25.0 million in debt during the year and funded approximately $14.0 million in capital spending.

Low Price Environment Initiatives

In response to the significant declines in benchmark oil prices that unfolded between November 2014 and February 2016, the Partnership conducted a comprehensive operating assessment of our portfolio to evaluate the economic viability of each well we operate. Wells that were not economically viable, at then prevailing prices, were shut-in provided there were no contractual, operating or reservoir constraints precluding the suspension of operations. Based on this assessment and beginning in late December 2015, we elected to shut-in approximately 10-15% of our wells, reducing expected operating costs by approximately 10-20% and forecast production by approximately 5-10%. In January 2016, Mid-Con Energy Operating reduced staffing by approximately 13%, which will result in lower salary allocations to us. Combined with our ongoing cost reduction initiatives targeting lower G&A and LOE, we project these actions will collectively deliver meaningful reductions of administrative overhead and per unit operating costs.

Commodity Prices

Our revenues and net income are sensitive to oil and natural gas prices which have been and are expected to continue to be highly volatile. In general, average oil and natural gas prices were significantly lower during the comparable periods of 2015 measured against 2014. In the fourth quarter of 2015, the front-month NYMEX-WTI futures price averaged approximately $42 per barrel, compared to approximately $73 per barrel in the fourth quarter of 2014. During 2015, the front-month NYMEX-WTI futures price ranged from a low of approximately $35 per barrel to a high of approximately $61 per barrel. Consequently, the Partnership experienced a significant operating margin deterioration and unit price decline.

Sustained low oil and natural gas prices could have a significant impact on the carrying value of our oil and natural gas properties, as well as the volumes and corresponding revenues of our estimated proved oil and natural gas reserves. In 2015, we recorded approximately $103.9 million of non-cash impairment expense. To quantify the impact of lower oil and natural gas prices, we provide the following examples. If the commodity prices used to calculate fair value for each of our oil and natural gas properties were reduced by 5% or 10%, we estimate the incremental non-cash impairment charges would approximate $37.2 million and $80.8 million, respectively.

Distributions

In 2015, the aggregate amount of cash distributions paid by the Partnership was approximately $11.3 million, which included distributions for the fourth quarter 2014 and first and second quarters of 2015. In October 2015, the Board of Directors elected to suspend payment of quarterly cash distributions and reserve excess cash. Our credit agreement stipulates written consent from our lenders is required in order to reinstate distributions and also prohibits us from making cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders.

Financing Activities

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

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

During November 2015, the semi-annual borrowing base redetermination and amendment of our underlying revolving credit facility was completed. The redetermination resulted in a decrease of our borrowing base from $220.0 million to $190.0 million, consisting of a $165.0 million conforming tranche, and includes monthly commitment reductions of $2.5 million each mandated through May 2016 and a $25.0 million non-conforming tranche. The credit facility amendment also designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. See Note 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Appointment and Departure of Certain Officers

We announced the following changes to the executive officer positions:

- Ms. Sherry L. Morgan was named Chief Accounting Officer of the General Partner, replacing Mr. David A. Culbertson whose resignation was effective on July 1, 2015.

- Dr. Michael L. Wiggins resigned from his role as President and Chief Engineer. His resignation was effective on July 1, 2015.

- Mr. Bradley A. Cox was named Executive Vice President of Business Development and Chief Engineer, replacing Dr. Michael L. Wiggins whose resignation was effective on July 1, 2015. Mr. Cox later resigned as Executive Vice President of Business Development and Chief Engineer, effective September 30, 2015.

Equity Awards

On November 20, 2015, the unitholders approved an amendment to the Long-Term Incentive Program that increased the number of common units available for issuance under the program from 1,764,000 to 3,514,000 common units. See our Form S-8 filed with the SEC for further details.

Business Environment

The markets for oil, natural gas and NGLs have been volatile and may continue to be volatile in the future, which means that the price of oil may fluctuate widely. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil reserves that we can economically produce and our access to capital. In late 2014, prices for oil, natural gas and NGLs began to decline, and prices continued to decline through December 2015. For perspective, prices for front month NYMEX-WTI crude oil futures traded within a range of $34.73 and $61.43 per barrel in 2015, ending the year at $37.04 per barrel while front month NYMEX Henry Hub natural gas futures traded within a range of $1.76 to $3.23 per MMBtu over the same period, ending the year at $2.34 per MMBtu.The dramatic decline in commodity prices has had an impact on our unit price. During 2015, our common unit price fluctuated between a closing high of $6.90 in February to a closing low of $1.10 in December.

The objective of our risk management program is to achieve more predictable cash flows by reducing our exposure to short-term fluctuations in the price of oil and natural gas. We believe this strategy will serve to secure a baseline portion of our revenues and, by retaining some opportunity to participate in upward price movements, may also enable us to realize higher revenues during periods when prices rise. To this end, we utilize commodity derivatives, namely swap, call and put contracts, to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts and/or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. We conduct our risk management activities exclusively with participant lenders in our revolving credit facility. In January 2015, we restructured a significant portion of our hedge portfolio to limit downside and volatility due to the then prevailing commodity price environment and in November 2015, we entered into additional oil commodity contracts covering a portion of our anticipated oil production in 2016 and 2017.

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

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

How We Evaluate Our Operations

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

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

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

- Oil and natural gas production volumes;
- Realized prices on the sale of oil and natural gas, including the effect of our commodity derivative contracts;
- Lease operating expenses; and
- Adjusted EBITDA.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess:

- the cash flow generated by our assets, without regard to financing methods, capital structure or historical cost basis; and
- our ability to incur and service debt and fund capital expenditures.

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

Critical Accounting Policies and Estimates

Accounting policies we consider significant are summarized in Note 2 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" of this report. Certain accounting policies require management to make critical accounting estimates. Accounting estimates are considered critical if the nature of the estimates and assumptions involves a high degree of subjectivity and judgment concerning uncertain matters and the impact of the estimates and assumptions is material to our financial position or results of operations. Additional information regarding our critical estimates is provided below.

Derivative Contracts and Hedging Activities

Current accounting rules require that all derivative contracts, other than those that meet specific exclusions, be recorded at fair value. Quoted market prices are the best evidence of fair value. If quotations are not available, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or on other valuation techniques. We use certain pricing models to determine the fair value of our derivative contracts. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We compare our estimates of the fair values of our derivative contracts with those provided by our counterparties. There have been no significant differences. For additional information regarding derivatives, see Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data."

Successful Efforts Method of Accounting

Accounting for oil and natural gas properties under the successful efforts method of accounting requires management to make estimates that may have a material impact on our financial position as they determine the carrying amount of our oil and natural gas properties, the amount of depletion expense recorded and the amount of impairment expense recorded. We believe the following to be critical accounting estimates associated with the successful efforts method of accounting of our oil and natural gas properties:

Oil and Natural Gas Reserves

Our estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. The estimates of our proved reserves as of December 31, 2015 are based on reserve reports prepared by our reservoir engineering staff and audited by Cawley, Gillespie & Associates, Inc. The estimates of reserves conform to the guidelines of the SEC, including the criteria of “reasonable certainty,” as it pertains to expectations about the recoverability of reserves in future years.

The accuracy of our reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgments of the individuals preparing the estimates. In addition, our proved reserve estimates are also a function of many assumptions, all of which could deviate significantly from actual results. For example, when the price of oil and natural gas increases, the economic life of our properties is extended, thus increasing estimated proved reserve quantities and making certain projects economically viable. Likewise, if oil and natural gas prices decrease, the properties economic life is reduced and certain projects may become uneconomic, reducing estimated proved reserve quantities. Oil and natural gas price volatility adds to the uncertainty of our reserve quantity estimates. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas and NGLs eventually recovered. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see “Supplementary Information” in Item 8. “Financial Statements and Supplementary Data” and see also Item 1. “Business.”

Impairment of Oil and Natural Gas Properties

We review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value exceeds management's estimate of fair value. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flow is less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flow to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and developmental costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in our estimated cash flows are the product of a process that begins with NYMEX-WTI forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. We review our oil and natural gas properties by amortization base (field) or by individual well for those wells not constituting part of an amortization base.

Asset Retirement Obligations

We have obligations under our lease agreements and federal regulations to remove equipment and restore land at the end of oil and natural gas production operations. These asset retirement obligations (“ARO”) are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or drilling a well. Determining the future restoration and removal 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 estimate the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. We are required to record the fair value of a liability for the ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We review our assumptions and estimates of future asset retirement obligations on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. Over time, the liability is accreted each period toward its future value and the capitalized cost is depleted as a component of development costs. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability. See Note 7 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Results of Operations

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

	Year Ended December 31,		
	2015	2014	2013
Revenues (in thousands):			
Oil sales	$ 72,520	$ 96,127	$ 85,080
Natural gas sales	1,394	784	656
Gain (loss) on derivatives, net	22,366	29,361	(5,675)
Total revenues	$ 96,280	$ 126,272	$ 80,061
Operating costs and expenses (in thousands):			
Lease operating expenses	$ 33,591	$ 26,091	$ 16,366
Oil and natural gas production taxes	$ 3,487	$ 6,325	$ 3,817
Impairment of proved oil and natural gas properties	$ 103,938	$ 30,206	$ 1,578
Depreciation, depletion and amortization	$ 34,174	$ 21,877	$ 14,421
General and administrative (1)	$ 9,411	$ 14,313	$ 12,244
Interest expense	$ 7,258	$ 4,731	$ 3,282
Production (Unaudited):			
Oil (MBbls)	1,623	1,112	907
Natural gas (MMcf)	571	157	128
Total (MBoe)	1,718	1,138	928
Average net production (Boe/d)	4,707	3,118	2,542
Average sales price (Unaudited):			
Oil (per Bbl):			
Sales price	$ 44.68	$ 86.45	$ 93.80
Effect of net settlements on commodity derivative instruments (2)	$ 12.86	$ 0.80	$ 0.32
Realized oil price after derivatives	$ 57.54	$ 87.25	$ 94.12
Natural gas (per Mcf):			
Sales price (3)	$ 2.44	$ 4.99	$ 5.13
Average unit costs per Boe (Unaudited):			
Lease operating expenses	$ 19.55	$ 22.93	$ 17.64
Oil and natural gas production taxes	$ 2.03	$ 5.56	$ 4.11
Depreciation, depletion and amortization	$ 19.89	$ 19.22	$ 15.54
General and administrative expenses	$ 5.48	$ 12.58	$ 13.19

(1) General and administrative expenses include non-cash equity-based compensation of $3.2 million, $7.4 million, and $6.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.
(2) Effects of net settlements on commodity derivative instruments does not include the $11.1 million received from restructuring the previous oil derivative contracts in January 2015.
(3) Natural gas sales price per Mcf includes the sale of natural gas liquids.

Factors Affecting the Comparability of the Historical Financial Results

The comparability of our results of operations among the periods presented is impacted by:

- The drilling of 31 wells in 2013, 52 wells in 2014 and 14 wells in 2015.
- Our acquisition in May 2013 of additional working interests in our Cushing properties located in the Northeastern Oklahoma core area and certain Southern Oklahoma units.
- Our acquisition in February 2014 of certain oil properties located in Cimarron, Love and Texas Counties, Oklahoma and Potter County, Texas from our Mid-Con Affiliate.
- Our acquisition in May 2014 of additional working interests in some of our Southern Oklahoma core area properties.
- Our acquisition in August 2014 of a waterflood unit in Liberty County, Texas.
- Our acquisition in August 2014 of an oil property located in Creek County, Oklahoma from our Mid-Con Affiliate.
- Our acquisition in November 2014 of multiple oil properties located in Coke, Coleman, Fisher, Haskell, Jones, Kent, Nolan, Runnels, Stonewall, Taylor and Tom Green Counties, Texas ("Permian").

As a result of the factors listed above, historical results of operations and period-to-period comparisons of these results and certain financial data may not be comparable or indicative of future results.

Year Ended December 31, 2015 Compared with Year Ended December 31, 2014

We reported net loss of approximately $95.5 million for the year ended December 31, 2015 compared to net income of approximately $22.5 million for the year ended December 31, 2014, a decrease of approximately $118.0 million. The change was primarily attributable to higher impairment charges, lower oil sales prices and higher depreciation, depletion and amortization ("DD&A") expense.

Sales Revenues. Revenues from oil and natural gas sales for the year ended December 31, 2015 were approximately $73.9 million as compared to approximately $96.9 million for the year ended December 31, 2014. Despite the year over year production growth resulting from the acquisition of properties in 2014, revenues were negatively affected by lower oil and natural gas prices. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the twelve months ended December 31, 2015 was approximately $44.68 compared to approximately $86.45 for the twelve months ended December 31, 2014. Commodity prices have been extremely volatile over the past 12 months and in the fourth quarter of 2015, the front-month NYMEX WTI futures price averaged approximately $42 per barrel, compared with approximately $73 per barrel in the fourth quarter of 2014. For the years ended 2015 and 2014, the front-month NYMEX WTI futures price ranged from a low of approximately $35 per barrel to a high of approximately $61 per barrel and from a low of approximately $53 per barrel to a high of approximately $107 per barrel, respectively.

On average, our production volumes for the year ended December 31, 2015 were approximately 1,718 MBoe, or approximately 4,707 Boe per day. In comparison, our total production volumes for the year ended December 31, 2014 were approximately 1,138 MBoe, or approximately 3,118 Boe per day. The increase in production volumes was primarily due to acquisitions of additional oil properties in 2014.

Effects of Commodity Derivative Contracts. We utilize NYMEX-WTI derivative contracts to hedge against changes in commodity prices. See Note 5 and Note 6 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data." and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk," for additional information about our commodity derivative contracts. To the extent the future commodity price outlook declines between measurement periods, we will have gains on our unsettled derivatives, net of deferred premiums. To the extent future commodity price outlook increases between measurement periods, we will have losses on our unsettled derivative contracts, including deferred premiums. For the twelve months ended December 31, 2015, we recorded a net gain of approximately $22.4 million, which was composed of approximately $39.6 million gain on net cash settlements of derivative contracts (which included $11.1 million of gain from settlements of early termination of derivative contracts) and approximately $17.2 million non-cash loss on changes in fair value of unsettled derivative contracts. For the twelve months ended December 31, 2014, we recorded a net gain from our commodity derivative contracts of approximately $29.4 million, which was composed of approximately $28.5 million non-cash gain on changes in fair value of unsettled derivative contracts and approximately $0.9 million gain on net cash settlements of derivative contracts.

Lease Operating Expenses. For the year ended December 31, 2015, our lease operating expenses were approximately $33.6 million, or $19.55 per Boe, compared to approximately $26.1 million, or approximately $22.93 per Boe, for the year ended December 31, 2014. The increase in total lease operating expenses for the year ended December 31, 2015 was primarily attributable to the acquisitions of additional oil properties in 2014. The decrease in average costs per Boe reflects the impact of our ongoing cost reduction initiatives combined with the November 2014 Permian acquisition, which added significantly lower LOE per Boe assets into our producing portfolio for a small portion of 2014 and for the full-year 2015.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues and exclude the effects of our commodity derivative contracts. Our production taxes for the year ended December 31, 2015 were approximately $3.5 million, or approximately $2.03 per Boe, for an effective tax rate of approximately 4.7% , compared to approximately $6.3 million, or approximately $5.56 per Boe, for an effective tax rate of approximately 6.5% for the year ended December 31, 2014. The decrease in production taxes during 2015 was attributable to lower oil and natural gas revenues driven by lower prices and to the approval by the Oklahoma Tax Commission of an EOR Production Tax Exemption for one of our Northeastern Oklahoma units. Based on a effective date of April 2013, the Partnership recouped approximately $0.8 million in cash production taxes previously paid. The EOR exemption will extend through March 2018. The decrease in production tax per Boe was primarily attributable to the 2014 acquisitions of properties in Texas that have a lower production tax rate as compared to our legacy properties in Oklahoma and to the effect of the EOR exemption. Excluding the effect of the amounts recouped from the EOR exemption that were attributable to prior periods, the effective tax rate for 2015 would have been 5.8%.

Impairment Expense. For the year ended December 31, 2015, we recorded approximately $103.9 million of non-cash impairment expense due to a continued decline in commodity prices. For the year ended December 31, 2014, we recorded approximately $30.2 million of non-cash impairment expense charge primarily in our Hugoton core area and also in our Southern Oklahoma core area due to reduced commodity prices and to a lesser degree, reduced reserve estimates.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the year ended December 31, 2015 were approximately $34.2 million, or approximately $19.89 per Boe, compared to approximately $21.9 million, or approximately $19.22 per Boe, for the year ended December 31, 2014. The increase in DD&A was primarily due to the increase in the total asset value of our oil and natural gas properties along with increased production from the acquisitions of additional oil properties in 2014. The increase in DD&A per Boe was due to higher depletion rates in some of the oil and gas properties acquired in 2014.

General and Administrative Expenses ("G&A"). G&A expenses were approximately $9.4 million, or approximately $5.48 per Boe, for the year ended December 31, 2015, compared to approximately $14.3 million, or approximately $12.58 per Boe, for the year ended December 31, 2014. The overall decrease in G&A expenses for the year ended December 31, 2015 was primarily due to lower compensation costs related to our non-cash equity-based compensation, resulting from lower price of our common units, and to lower payroll costs along with lower non-recurring legal and professional service costs related to acquisitions. The decrease in G&A expenses reflects the Partnership's efforts to focus on our production and development activities while containing administrative costs. G&A expenses included non-cash equity-based compensation of approximately $3.2 million and approximately $7.4 million for the twelve months ended December 31, 2015 and 2014, respectively.

Interest Expense. Our interest expense for the year ended December 31, 2015 was approximately $7.3 million, compared to approximately $4.7 million for the year ended December 31, 2014. The increase in interest expense in 2015 compared to 2014 was due to higher borrowings outstanding from our revolving credit facility resulting from acquisitions of oil properties in November 2014.

Year Ended December 31, 2014 Compared with Year Ended December 31, 2013

Net income was approximately $22.5 million for the year ended December 31, 2014 compared to approximately $28.2 million for the year ended December 31, 2013, a decrease of approximately $5.7 million. The change was primarily attributable to higher impairment charges to our oil and natural gas properties along with higher lease operating expenses and higher DD&A. Partially offsetting these unfavorable costs was the favorable net impact of changes in the mark-to-market value of our unsettled derivative contracts and an increase in oil production during 2014.

Sales Revenues. Revenues from oil and natural gas sales for the year ended December 31, 2014 were approximately $96.9 million as compared to approximately $85.7 million for the year ended December 31, 2013. The increase in revenues was driven primarily by year over year production growth which included incremental volumes from acquisitions of properties in 2014, partially offset by the negative effect of lower oil and natural gas prices.

On average, our production volumes for the year ended December 31, 2014 were approximately 1,138 MBoe, or approximately 3,118 Boe per day. In comparison, our total production volumes for the year ended December 31, 2013 were approximately 928 MBoe, or approximately 2,542 Boe per day on average. Our legacy assets' production declined due to the natural declines and conversion of some producing wells to injectors but was offset by the production from the acquisitions of oil properties in 2014 and the favorable impact of our drilling and recompletion efforts in 2014. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the year ended December 31, 2014 was $86.45, compared with $93.80 for the year ended December 31, 2013.

Effects of Commodity Derivative Contracts. We utilize NYMEX-WTI derivative contracts to hedge against changes in commodity prices. We use certain pricing models to determine the fair value of our derivative contracts. Inputs to the pricing models include market quotes and pricing analysis. See Note 5, Note 6 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk," for additional information about our commodity derivative contracts. To the extent the future commodity price outlook increases or decreases between measurement periods, we will have losses and gains, respectively, on our unsettled derivative contracts. Due to the period change in the mark-to-market value of these contracts, we recorded a net gain from our commodity derivative contracts for the year ended December 31, 2014 of approximately $29.4 million, which was composed of a non-cash gain on unsettled derivative contracts of approximately $28.5 million, resulting from the decline in future commodity prices, and approximately a $0.9 million gain on net cash settlements of derivative contracts. For the year ended December 31, 2013, we recorded a net loss from our commodity derivative contracts of approximately $5.7 million, which was composed of a non-cash loss on unsettled derivative contracts of approximately $6.0 million and a gain of approximately $0.3 million on net cash settlements of derivative contracts.

Lease Operating Expenses. For the year ended December 31, 2014, our lease operating expenses were approximately $26.1 million, or $22.93 per Boe, compared to approximately $16.4 million, or approximately $17.64 per Boe, for the year ended December 31, 2013. The increase in total lease operating expenses for the year ended December 31, 2014 was primarily attributable to the acquisition of additional oil properties in 2014 and the additional number of producing wells resulting from our drilling and recompletion programs. In 2014, the increase in average costs per Boe reflects higher costs of operations in comparison to the proportional increases in production in our Hugoton and Southern Oklahoma core areas. In addition, the average lease operating expenses per Boe was higher due to additional workover costs related to non-recurring expenses of approximately $1.3 million on a year to year comparison. Ad valorem taxes are also included in lease operating expenses and the taxes are levied on our properties in Colorado and Texas and are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts.

Production Taxes. For the year ended December 31, 2014, production taxes were calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. Our production taxes were approximately $6.3 million, or approximately $5.56 per Boe, for an effective tax rate of approximately 6.5%, compared to approximately $3.8 million, or approximately $4.11 per Boe, for an effective tax rate of approximately 4.5%, for the year ended December 31, 2013. The increase in both production taxes and the rate per Boe during 2014 was directly related to the expiration of a reduced production tax rate on a majority of our production that qualified for the Oklahoma Enhanced Recovery Project Gross Production Tax Exemption. The tax exemption was in effect for the majority of our production from Southern Oklahoma properties in 2013. Also, the acquisition of additional properties during 2014 added to the increase in production taxes.

Impairment Expense. For the year ended December 31, 2014, we recorded approximately $30.2 million of non-cash impairment expense primarily in our Hugoton core area and also in our Southern Oklahoma core area due to reduced recoverable reserve estimates from current forward oil pricing. For the year ended December 31, 2013, we recorded approximately $1.6 million of non-cash impairment expense within our miscellaneous core area properties due to reduced recoverable reserve estimates.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the year ended December 31, 2014 were approximately $21.9 million, or approximately $19.22 per Boe, compared to approximately $14.4 million, or approximately $15.54 per Boe, for the year ended December 31, 2013. The increase in DD&A was primarily due to the increase in the total asset value of our oil and natural gas properties along with increased production from the acquisitions of additional oil properties in 2014. The increase in DD&A per Boe was due to a reduction in reserves in some of our legacy assets and higher depletion rates of the properties acquired in 2014 compared to our legacy assets.

General and Administrative Expenses. For the year ended December 31, 2014, G&A expenses were approximately $14.3 million, or approximately $12.58 per Boe produced compared to approximately $12.2 million, or approximately $13.19 per Boe produced, for the year ended December 31, 2013. The overall increase in G&A expenses for the year ended December 31, 2014 was primarily due to an increase in compensation costs related to our non-cash equity-based compensation plan in addition to higher non-recurring legal and professional service costs related to our acquisitions in 2014 and filing our registration statement and related amendments. Non-cash equity-based compensation expense was $7.4 million and $6.4 million for the years ended December 31, 2014 and 2013, respectively. The decrease in total G&A expenses per Boe was attributable to increased production in 2014.

Interest Expense. Our interest expense for the year ended December 31, 2014 was approximately $4.7 million, compared to approximately $3.3 million for the year ended December 31, 2013. The increase in interest expense in 2014 compared to 2013 was due to higher borrowings outstanding from our revolving credit facility resulting from acquisitions in 2014.

Liquidity and Capital Resources

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

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

Our liquidity position at December 31, 2015 consisted of approximately $0.6 million of available cash and $7.5 million of available borrowings under our revolving credit facility. Our borrowing base is re-determined on or about April 30 and October 31 of each year. During the November 2015 redetermination, our borrowing base was reduced from $220.0 million to $190.0 million, consisting of a $165.0 million conforming tranche which requires monthly commitment reductions of $2.5 million each month through May 2016 and a $25.0 million non-conforming tranche. The non-conforming tranche matures May 1, 2016, requiring our outstanding debt balance to be paid down to $150.0 million at that time. As of December 31, 2015, the mark-to-market value of our net derivative financial instruments totaled $25.6 million. If necessary, the value of our net derivative financial instruments could be monetized and or combined with a portion of operating cash flows to satisfy debt maturities in 2016. Preliminary conversations with our lenders suggest the Partnership will not be compelled to monetize hedges to reduce debt during the upcoming spring 2016 bi-annual borrowing base redetermination. At this time, it appears more likely that the Partnership and its lenders will reach an accommodation comparable to the one reached by these same participant parties during our fall 2015 bi-annual borrowing base redetermination.

Based on our cash balance, forecasted cash flows from operating activities, ability to monetize our hedges, if necessary, 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 in 2016. Although we currently expect our sources of cash to be sufficient to meet our near-term liquidity needs, there can be no assurance that the lenders under our revolving credit facility will not reduce the borrowing base to an amount below our outstanding borrowings or that our liquidity requirements will continue to be satisfied, given current oil prices and the discretion of our lenders to decrease our borrowing base. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in some cases, ceased to provide any new funding.

Cash Flows

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

	Year Ended December 31,		
	2015	2014	2013
Operating activities	$ 48,425	$ 50,464	$ 56,634
Investing activities	$ (13,894)	$ (189,323)	$ (50,423)
Financing activities	$ (37,148)	$ 140,657	$ (5,830)

Operating Activities. Net cash provided by operating activities was approximately $48.4 million, $50.5 million and $56.6 million for the years ended December 31, 2015, 2014 and 2013, respectively. The $2.1 million decrease from December 31, 2014 to December 31, 2015 was primarily attributable to decreased oil sales revenues due to lower oil prices and a decrease in working capital, primarily related to lower accounts receivable as a result of lower oil and natural gas sales, offset by higher cash settlements on derivatives. The $6.1 million decrease from December 31, 2013 to December 31, 2014 was primarily due to increased oil sales offset by higher lease operating expenses, production taxes, and an increase in working capital primarily related to receivables from working capital settlement receivables from our November acquisition and from our commodity derivative contracts.The increase in expenses, receivables and prepayments were offset by higher oil and natural gas revenues in 2014 which were driven by higher production.

Investing Activities. Net cash used in investing activities was approximately $13.9 million, $189.3 million and $50.4 million for the years ended December 31, 2015, 2014 and 2013, respectively. Cash used in investing activities during the twelve months ended December 31, 2015 included approximately $13.9 million on capital expenditures, primarily for drilling, development and completion activities. Cash used for investing activities during 2014 included approximately $155.4 million for the acquisition of oil properties and additional working interests. Cash related to the acquisitions in 2014 included approximately $7.0 million and $4.5 million for the properties acquired from our Mid-Con Affiliate in February and August, respectively, the acquisition of working interest in our Southern Oklahoma core area in May for approximately $7.3 million, the Liberty County waterflood unit acquired in August for approximately $18.9 million and the Permian properties acquired in November 2014 for approximately $117.6 million. Other small acquisitions totaled $0.1 million in 2014. We also spent approximately $34.3 million on capital expenditures, primarily for drilling, development and completion activities. Cash used in investing activities during 2013 included $27.4 million for the purchase of additional working interest in the Cushing properties and certain Southern Oklahoma properties. We also spent $22.4 million on capital expenditures, primarily for drilling, development and completion activities.

Financing Activities. Our cash flows from financing activities consisted primarily of proceeds from and payments on our revolving credit facility, proceeds from the issuance of common units and distributions to unitholders. Net cash provided by and (used in) financing activities was approximately ($37.1 million), $140.6 million and ($5.8 million), for the years ended December 31, 2015, 2014 and 2013, respectively. During the year ended December 31, 2015, cash used by financing activities included net payments on our revolving credit facility of approximately $25.0 million, distributions to unitholders of approximately $11.3 million, debt issuance costs of approximately $0.7 million related to our debt redetermination and approximately $0.1 million of incremental offering costs from our November 2014 public offering. During the year ended December 31, 2014, cash provided by financing activities included net proceeds of approximately $96.0 million from our November equity offering which was used to finance the acquisition of multiple oil properties in the Permian, approximately $93.0 million of net proceeds from our revolving credit facility which were used to finance a portion of our acquisitions during the year and approximately $44.6 million of distributions to unitholders. During the year ended December 31, 2013, cash used in financing activities included distributions to unitholders of approximately $39.8 million and net proceeds from our revolving credit facility of approximately $34.0 million which were used to finance the acquisition of additional working interest in our Northeastern Oklahoma and Southern Oklahoma core areas, and to develop capital projects.

Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations in order to increase and maintain our production and the size of our asset base. The primary purpose of growth capital is to acquire and develop producing assets that allow us to increase our production and asset base. Given the current commodity pricing situation, which has oil prices at twelve-year lows, we have limited capital spending to include only the most economically viable development projects. To date, we have funded acquisition transactions through a combination of cash, available borrowing capacity under our revolving credit facility and through the issuance of equity.

In 2015, our capital spending program for the development, growth and maintenance of our oil and natural gas properties, including projects for our properties acquired in 2014, was approximately $13.9 million. We currently expect 2016 spending to be approximately $9.0 million. We will consider adjustments to this capital program based on surplus operating cash flows in concert with our evaluation of additional development opportunities that are identified during the year.

We had no significant acquisitions of oil and natural gas properties in 2015. The fair value of oil and natural gas properties acquired during the year ended December 31, 2014 totaled approximately $240.8 million. The significant acquisitions in 2014 were related to the properties acquired from our Mid-Con Affiliate in February and August, the Liberty County, Texas waterflood unit acquisition in August, and the Permian properties acquired in November. See Note 3 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information regarding our acquisitions.

Revolving Credit Facility

We have a $250.0 million senior-secured revolving credit facility that expires in November 2018. At December 31, 2015, our borrowing base was $187.5 million, consisting of a $162.5 million conforming tranche and a $25.0 million non-conforming tranche. The non-conforming tranche matures on May 1, 2016.

During November 2015, the semi-annual redetermination of our borrowing base and amendment of the underlying revolving credit facility was completed. This redetermination resulted in a borrowing base of $190.0 million, consisting of a $165.0 million conforming tranche to which six monthly commitment reductions of $2.5 million each were mandated through May 2016 and a $25.0 million non-conforming tranche. The credit facility amendment designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. This redetermination also required that by December 10, 2015 we enter into commodity derivative contracts of not less than 80% of our 2016 projected monthly production and not less than 50% of our 2017 projected monthly production. These requirements were satisfied during November 2015 with the execution of additional commodity derivative contracts maturing in 2016 and 2017. Borrowings under our amended credit facility are secured by liens on not less than 90% of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to our unitholders.

At December 31, 2015, we had approximately $180.0 million of borrowings outstanding under our revolving credit facility. The facility requires us and our subsidiaries to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0, and a Current Ratio of not less than 1.0 to 1.0. We were in compliance with these covenants as of and during the year ended December 31, 2015.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of 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 1.0% to 2.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the conforming borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 2.0% to 3.75% per annum according to the borrowing base usage. For the year ended December 31, 2015, the average effective interest rate was approximately 3.0%. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

The borrowing base is determined by the lenders participating in our credit facility based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary. The borrowing base is subject to scheduled redeterminations on or about April 30 and October 31 of each year with an additional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a commodity derivative contract.

During April 2015, our borrowing base under the revolving credit facility was decreased from $240.0 million to $220.0 million. No other material terms of the original credit agreement were amended.

During November 2014, our borrowing base under the revolving credit facility was increased from $190.0 million to $240.0 million. The amendment added MUFG Union Bank, N.A. and Frost Bank as additional lenders. No other material terms of the original credit agreement were amended.

During August and April 2014, our borrowing base under the revolving credit facility was increased from $150.0 million to $170.0 million and from $170.0 million to $190.0 million, respectively. No other material terms of the original credit agreement were amended.

See Note 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information about our revolving credit facility.

Derivative Contracts

Our risk management program is intended to reduce our exposure to commodity prices and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and NYMEX-WTI futures prices. As of December 31, 2015, we have commodity derivative contracts covering approximately 81% and 46% of our calendar years 2016 and 2017 average daily production (calculated based on the mid-point of our production guidance released on February 29, 2016).

At December 31, 2015, our open commodity derivative contracts were in a net asset position with a fair value of approximately $25.6 million. All of our commodity derivative contracts are with major financial institutions that are also members of our banking group. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss. As of December 31, 2015, all of our counterparties have performed pursuant to the obligations specified in their commodity derivative contracts.

At December 31, 2015, our derivative contracts had maturities in 2016 and 2017 and were comprised of commodity price swap, call and put contracts. For commodity price swap contracts, at the time of execution the seller agrees to receive a fixed price at maturity in exchange for any gains or losses that might be realized from allowing the price of the underlying to float with the market until maturity. From the perspective of the seller, these instruments limit exposure to price declines below the price fixed by the swap at the expense of participating in any price increases above the price fixed by the swap.

For commodity price call contracts, in return for a premium received, which can be effected at either execution or settlement, the seller is obliged to pay the difference, when positive, between the market price of the underlying at maturity less the strike price. From the perspective of the seller, these instruments provide income via the premium received at the expense of any incremental gains that would have otherwise been received above the strike price.

For commodity price puts, in return for a premium paid, which can be effected at either execution or settlement, the purchaser has the right to receive the difference, when positive, between the strike price and the market price of the underlying at maturity. From the perspective of the purchaser, these instruments limit exposure to price declines below the strike price at the expense of premiums paid.

We do not designate commodity derivative contracts as hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of unsettled derivative contracts is recorded in current period earnings as a net non-cash gain or loss on unsettled derivatives. 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. Net settlement gains or losses on derivative contracts only arise from net payments made or received on monthly settlements or if a commodity derivative contract is terminated prior to its expiration and are reported as net settlements on derivatives in the consolidated statements of operations.

See Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information regarding our derivative contracts.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2015 (in thousands). The contractual obligations we will actually pay in future periods may vary from those reflected in the table because the estimates and assumptions are subjective.

	2016	2017	2018	Total
Revolving credit facility [(1)]	$ 30,000	$ —	$ 150,000	$ 180,000
Interest on long-term debt [(2)]	6,396	6,000	5,079	17,475
Deferred premiums for derivatives	5,040	4,932	—	9,972
Total	$ 41,436	$ 10,932	$ 155,079	$ 207,447

(1) For purposes of this table, we have assumed that under our revolving credit facility the non-conforming borrowings will be paid in 2016 and the conforming borrowings will not be paid until the maturity date on November 5, 2018.

(2) The interest obligation is based on a 4.0% borrowing rate at December 31, 2015.

Our ARO is not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of our ARO at December 31, 2015 was $12.7 million.

Off–Balance Sheet Arrangements

At December 31, 2015, we had no off–balance sheet arrangements.

Recently Issued Accounting Pronouncements

See Note 2 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information regarding recently issued accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

Our risk management program is intended to reduce exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivatives, namely swap, call and put contracts, to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts and/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.

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

Our commodity price risk management activities are recorded at fair value and thus changes to the future commodity prices could have the effect of reducing net income and the value of our securities. The fair value of our oil commodity contracts at December 31, 2015 was a net asset of approximately $25.6 million. A 10% change in oil prices, with all other factors held constant, would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil commodity derivative contracts of approximately $6.0 million. See Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Interest Rate Risk

Our exposure to changes in interest rates relates primarily to debt obligations. At December 31, 2015, we had debt outstanding of $180.0 million, with an effective interest rate of 3.0%. Assuming no change in the amount outstanding, the impact on interest expense of a 10% increase or decrease in the average interest rate would be approximately $0.5 million on an annual basis. At December 31, 2015, our revolving credit facility allowed for borrowings up to $187.5 million at an interest rate ranging from LIBOR plus a margin ranging from 2.0% to 3.75% or the prime rate plus a margin ranging from 1.0% to 2.75%, depending on the amount borrowed. The prime rate will be the United States prime rate as announced from time-to-time by Wells Fargo Bank, National Association. See Note 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Counterparty and Customer Credit Risk

We are subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current 2015 production. The inability or failure of any of our customers to meet its obligations to us or its insolvency or liquidation may adversely affect our financial results. We monitor our exposure to these counterparties primarily by reviewing credit ratings and payment history. As of December 31, 2015, we had three customers that each accounted for 10% or more of our consolidated total revenues. They all had positive payment histories and one had an investment grade credit rating at December 31, 2015.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Mid-Con Energy Partners, LP

We have audited the accompanying consolidated balance sheets of Mid-Con Energy Partners, LP (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2015 and 2014, and the related consolidated statements of operations, cash flows, and changes in equity for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership’s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mid-Con Energy Partners, LP and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 29, 2016

Mid-Con Energy Partners, LP and subsidiaries
Consolidated Balance Sheets
(in thousands, except number of units)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 615	$ 3,232
Accounts receivable:		
Oil and natural gas sales	4,551	8,051
Other	5,009	4,070
Derivative financial instruments	24,419	26,202
Prepaids and other	623	652
Total current assets	35,217	42,207
Property and Equipment:		
Oil and natural gas properties, successful efforts method:		
Proved properties	518,916	501,191
Accumulated depletion, depreciation, amortization and impairment	(232,008)	(93,896)
Total property and equipment, net	286,908	407,295
Derivative financial instruments	1,144	842
Other assets	3,817	4,284
Total assets	$ 327,086	$ 454,628
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 3,185	$ 3,630
Related parties	559	3,989
Accrued liabilities	165	397
Current maturities of long-term debt	30,000	—
Total current liabilities	33,909	8,016
Other long-term liabilities	—	107
Long-term debt	150,000	205,000
Asset retirement obligations	12,679	7,363
Commitments and contingencies		
EQUITY, per accompanying statements:		
Partnership equity:		
General partner interest	47	1,328
Limited partners-29,724,890 and 29,166,112 units issued and outstanding as of December 31, 2015 and 2014, respectively	130,451	232,814
Total equity	130,498	234,142
Total liabilities and equity	$ 327,086	$ 454,628

See accompanying notes to consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Consolidated Statements of Operations
(in thousands, except per unit data)

	Year Ended December 31,		
	2015	2014	2013
Revenues:			
Oil sales	$ 72,520	$ 96,127	$ 85,080
Natural gas sales	1,394	784	656
Gain (loss) on derivatives, net	22,366	29,361	(5,675)
Total revenues	96,280	126,272	80,061
Operating costs and expenses:			
Lease operating expenses	33,591	26,091	16,366
Oil and natural gas production taxes	3,487	6,325	3,817
Impairment of proved oil and natural gas properties	103,938	30,206	1,578
Depreciation, depletion and amortization	34,174	21,877	14,421
Accretion of discount on asset retirement obligations	432	250	173
General and administrative	9,411	14,313	12,244
Total operating costs and expenses	185,033	99,062	48,599
Income (loss) from operations	(88,753)	27,210	31,462
Other income (expense):			
Interest income and other	558	13	9
Interest expense	(7,258)	(4,731)	(3,282)
Loss on settlement of ARO	(42)	—	—
Total other expense	(6,742)	(4,718)	(3,273)
Net income (loss)	$ (95,495)	$ 22,492	$ 28,189
Computation of net income (loss) per limited partner unit:			
General partner's interest in net income (loss)	$ (1,146)	$ 354	$ 518
Limited partners' interest in net income (loss)	$ (94,349)	$ 22,138	$ 27,671
Net income (loss) per limited partner unit:			
Basic	$ (3.18)	$ 0.98	$ 1.44
Diluted	$ (3.18)	$ 0.98	$ 1.44
Weighted average limited partner units outstanding:			
Limited partner units (basic)	29,642	22,499	19,234
Limited partner units (diluted)	29,642	22,518	19,249

See accompanying notes to consolidated financial statements

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

	Year Ended December 31,		
	2015	2014	2013
Cash Flows from Operating Activities:			
Net income (loss)	$ (95,495)	$ 22,492	$ 28,189
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	34,174	21,877	14,421
Debt issuance costs amortization	1,156	348	168
Accretion of discount on asset retirement obligations	432	250	173
Impairment of proved oil and natural gas properties	103,938	30,206	1,578
Loss on settlement of ARO	42	—	—
Cash paid for settlements of ARO	(82)	—	—
Mark to market on derivatives:			
(Gain) loss on derivatives, net	(22,366)	(29,361)	5,675
Cash settlements received for matured derivatives	28,543	891	288
Cash settlements received for early terminations and modifications of derivatives, net	11,069	—	—
Cash premium paid for derivatives, net	(15,765)	—	—
Non-cash equity-based compensation	3,204	7,394	6,376
Changes in operating assets and liabilities:			
Accounts receivable	3,500	(1,273)	(365)
Other receivables	(566)	(3,966)	499
Prepaids and other	29	(461)	(526)
Accounts payable and accrued liabilities	(3,388)	2,067	158
Net cash provided by operating activities	48,425	50,464	56,634
Cash Flows from Investing Activities:			
Additions to oil and natural gas properties	(13,893)	(33,969)	(22,366)
Acquisitions of oil and natural gas properties	(1)	(155,354)	(28,057)
Net cash used in investing activities	(13,894)	(189,323)	(50,423)
Cash Flows from Financing Activities:			
Proceeds from line of credit	28,000	168,000	105,000
Payments on line of credit	(53,000)	(75,000)	(71,000)
Issuance of common units	—	96,010	—
Offering costs	(194)	—	—
Distributions paid	(11,266)	(44,564)	(39,830)
Debt issuance costs	(688)	(3,789)	—
Net cash (used in) provided by financing activities	(37,148)	140,657	(5,830)
Net (decrease) increase in cash and cash equivalents	(2,617)	1,798	381
Beginning cash and cash equivalents	3,232	1,434	1,053
Ending cash and cash equivalents	$ 615	$ 3,232	$ 1,434
Supplemental Cash Flow Information:			
Cash paid for interest	$ 6,070	$ 4,600	$ 2,803
Non-Cash Investing and Financing Activities:			
Accrued capital expenditures - oil and natural gas properties	$ 716	$ 1,277	$ 926
Common units issued - acquisition of oil properties	$ —	$ 86,001	$ —

See accompanying notes to consolidated financial statements

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

	General Partner	Limited Partner Units	Limited Partner Amount	Total Equity
Balance, December 31, 2012	$ 1,814	18,991	$ 70,367	$ 72,181
Equity-based compensation	115	328	6,133	6,248
Distributions	(731)	—	(39,099)	(39,830)
Net income	518	—	27,671	28,189
Balance, December 31, 2013	$ 1,716	19,319	$ 65,072	$ 66,788
Equity-based compensation	—	332	7,415	7,415
Issuance of limited partner units - acquisitions	—	3,715	86,001	86,001
Issuance of limited partner units, net of offering costs	—	5,800	96,010	96,010
Distributions	(742)	—	(43,822)	(44,564)
Net income	354	—	22,138	22,492
Balance, December 31, 2014	$ 1,328	29,166	$ 232,814	$ 234,142
Equity-based compensation	—	559	3,311	3,311
Offering costs	—	—	(194)	(194)
Distributions	(135)	—	(11,131)	(11,266)
Net loss	(1,146)	—	(94,349)	(95,495)
Balance, December 31, 2015	$ 47	29,725	$ 130,451	$ 130,498

See accompanying notes to consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations

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

Reclassifications

The consolidated financial statements for previous periods include certain reclassifications to the derivative accounts that were made to conform to current presentation. Such reclassifications have no impact on previously reported total assets, net income (loss) or total operating cash flows.

Liquidity and Capital Resources

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

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

Our liquidity position at December 31, 2015 consisted of approximately $0.6 million of available cash, and $7.5 million of available borrowings under our revolving credit facility. Our borrowing base is re-determined on or about April 30 and October 31 of each year. During the November 2015 redetermination, our borrowing base was reduced from $220.0 million to $190.0 million , consisting of a $165.0 million conforming tranche which requires monthly commitment reductions of $2.5 million each month through May 2016 and a $25.0 million non-conforming tranche. The non-conforming tranche matures May 1, 2016, requiring our outstanding debt balance to be paid down to $150.0 million at that time. As of December 31, 2015, the mark-to-market value of our net derivative financial instruments totaled $25.6 million . If necessary, the value of our net derivative financial instruments could be monetized and or combined with a portion of operating cash flows to satisfy debt maturities in 2016. Preliminary conversations with our lenders suggest the Partnership will not be compelled to monetize hedges to reduce debt during the upcoming spring 2016 bi-annual borrowing base redetermination. At this time, it appears more likely that the Partnership and its lenders will reach an accommodation comparable to the one reached by these same participant parties during our fall 2015 bi-annual borrowing base redetermination.

Based on our cash balance, forecasted cash flows from operating activities, ability to monetize our hedges, if necessary, 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 in 2016. Although we currently expect our sources of cash to be sufficient to meet our near-term liquidity needs, there can be no assurance that the lenders under our revolving credit facility will not reduce the borrowing base to an amount below our outstanding borrowings or that our liquidity requirements will continue to be satisfied, given current oil prices and the discretion of our lenders to decrease our borrowing base. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in some cases, ceased to provide any new funding.

Note 2. Summary of Significant Accounting Policies

Basis of presentation and principles of consolidation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2015 and 2014. These financial statements also include the results of our operations, cash flows and changes in equity for the years ended December 31, 2015, 2014 and 2013.

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Our subsidiary is Mid-Con Energy Properties. All intercompany transactions and account balances have been eliminated.

We aggregate all of our oil and natural gas properties into one business segment engaged in the exploitation, development and production of oil and natural gas properties.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. Depletion and impairment of oil and natural gas properties, in part, are determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, asset retirement obligations, fair value of assets acquired and liabilities assumed in business combinations and fair value of derivative financial instruments.

Cash and cash equivalents

We consider all cash on hand, depository accounts held by banks and money market accounts with an original maturity of three months or less to be cash equivalents.

Accounts receivable

Accounts receivable are generated from the sale of oil and natural gas to various customers. We routinely assess the financial strength of our customers and bad debts are recorded based on an account level review after all means of collection have been exhausted, and the potential recovery is considered remote. At December 31, 2015 and 2014, we did not have any reserves for doubtful accounts and we did not incur any expenses related to bad debts in any period presented.

Revenue recognition

We follow the sales method of accounting for oil and natural gas revenues. Under this method, revenues are recognized based on our share of actual proceeds from oil and natural gas sold to purchasers. Natural gas revenues would not have been significantly altered for the period presented had the entitlements method of recognizing natural gas revenues been utilized. If reserves are not sufficient to recover natural gas overtake positions, a liability is recorded. We had no significant natural gas imbalances at December 31, 2015 or 2014.

Oil and natural gas properties

We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized costs relating to proved properties are depleted using the units-of-production method based on proved reserves on a field basis. The depreciation of capitalized production equipment is based on the units-of-production method using proved developed reserves on a field basis.

Capitalized costs of individual properties abandoned or retired are charged to accumulated depletion, depreciation and amortization. Proceeds from sales of individual properties are credited to property costs. No gain or loss is recognized until the entire amortization base (field) is sold or abandoned.

Costs of significant non-producing properties and wells in the process of being drilled are excluded from depletion until such time as the proved reserves are established or impairment is determined. Costs of significant development projects are excluded from depletion until the related project is completed. We had no significant costs excluded from depreciation during any of the periods presented. We capitalize interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. We had no capitalized interest during any of the periods presented.

We review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves and risk-adjusted probable and possible reserves. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimate quantities of oil and natural gas reserves. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. We review our oil and natural gas properties by amortization base (field) or by individual well for those wells not constituting part of an amortization base. These evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. Cash flow estimates for the impairment testing excludes derivative instruments used to mitigate the price risk related to lower future oil and natural gas prices.

We have obligations under our lease agreements and federal regulations to remove equipment and restore land at the end of oil and natural gas production operations. These asset retirement obligations (“ARO”) are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or drilling a well. Determining the future restoration and removal 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 estimate the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. We are required to record the fair value of a liability for the ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We review our assumptions and estimates of future asset retirement obligations on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. Over time, the liability is accreted each period toward its future value and the capitalized cost is depleted as a component of development costs. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability. See Note 7 for additional information.

Derivatives and hedging

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 derivatives, namely swap, call and put contracts, to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts and/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.

Derivatives are recorded at fair value and are presented on a net basis on the consolidated balance sheets as assets or liabilities. The Company nets the fair value of derivatives by counterparty where the right of offset exists. The Company determines the fair value of its derivatives by utilizing certain pricing models to validate the data provided by third parties. See Note 6 Fair Value Disclosures for more information.

We do not designate derivatives as hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of unsettled derivative contracts is recorded in current period earnings. When prices for oil are volatile, a significant portion of the effect of our hedging activities consists of non-cash income or expenses due to changes in the fair value of our commodity derivative contracts. In addition to mark-to-market adjustments, gains or losses arise from net payments made or received on monthly settlements, proceeds or payments for termination of contracts prior to their expiration and premiums paid or received for new contracts. Any deferred premiums are recorded as a liability and recognized in earnings as the related contracts mature. Gains and losses on derivatives are included in cash flows from operating activities. See Note 5 for discussion regarding Derivative Financial Instruments.

Equity-based compensation

The cost of employee services received in exchange for equity instruments is measured based on the grant-date fair value and is recorded as compensation expense over the requisite service period (often the vesting period). Awards subject to performance criteria vest when it is probable that the performance criteria will be met. Compensation expense for these awards is recorded upon vesting, based on their grant-date fair value, net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. No compensation expense is recognized for equity instruments that do not vest.

Debt issuance costs

Debt placement costs are stated at cost, net of amortization, which is computed using the straight-line method and recognized as interest expense in the consolidated statements of operations. Since our debt consists of a revolving credit facility, net debt placement costs are presented in "Other Assets" in our consolidated balance sheets. When debt is retired before its scheduled maturity date, we write off any remaining issuance costs associated with that debt.

Income taxes

We are a partnership that is not taxable for federal income tax purposes. As such, we do not directly pay federal income tax. As appropriate, our taxable income or loss is includable in the federal income tax returns of our unitholders. Earnings or losses for financial statement purposes may differ significantly from those reported to the individual unitholders for income tax purposes as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

Net income (loss) per limited partner unit

Basic net income (loss) per partner unit is computed by dividing net income (loss) by the weighted-average number of common shares outstanding for the period. Diluted net income (loss) per partner unit reflects the potential dilution of non-vested restricted stock awards. For the year ended December 31, 2015, this potentially dilutive item was anti-dilutive due to the Company's net loss and, therefore, was excluded from the calculation of diluted net income (loss) per partner unit.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued a comprehensive new revenue recognition standard that supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition,* and industry-specific guidance in Subtopic 932-605, *Extractive Activities-Oil and Gas-Revenue Recognition* . The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring those goods or services. The new standard also requires significantly expanded disclosure regarding the qualitative and quantitative information of an entity's nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The standard creates a five-step model that requires companies to exercise judgment when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard's application impact to individual financial statement line items. This standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements upon adoption of this standard.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Interest: *Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs.* The update requires debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability instead of being presented as an asset. Debt disclosures will include the face amount of the debt liability and the effective interest rate. The update requires retrospective application and represents a change in accounting principle. The update is effective for annual reporting periods beginning after December 15, 2015, and Management does not believe this pronouncement impacts our consolidated financial statements and related disclosures. The guidance in ASU 2015-03 does not address presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements. In August 2015, the FASB issued Accounting Standards Update No. 2015-15, *Presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements.* The pronouncement confirms that fees related to line-of-credit arrangements are not addressed in ASU 2015-03. Deferred initial up-front commitment fees paid by a borrower to a lender represent the benefit of being able to access capital over the contractual term, and therefore, meet the definition of an asset, while debt issuance costs in the scope of ASU 2015-03 do not. We will continue to present such costs as an asset and subsequently amortize the costs over the term of our revolving credit facility.

Note 3. Acquisitions

The following acquisitions were accounted for under the acquisition method of accounting. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition dates, while transaction and integration costs associated with the acquisitions were expensed as incurred. The results of all acquisitions have been included in the consolidated financial statements since the acquisition dates.

2014 Acquisitions

Permian acquisition

During November 2014, we acquired multiple oil properties located in Coke, Coleman, Fisher, Haskell, Jones, Kent, Nolan, Runnels, Stonewall, Taylor and Tom Green Counties, Texas ("Permian") for an aggregate purchase price of approximately $117.1 million after post-closing purchase price adjustments. The transaction was primarily funded with borrowings under our revolving credit facility of approximately $21.6 million in cash and the issuance of 5,800,000 common units having an approximate value of $96.0 million, net of offering costs. During 2015, we finalized our acquisition accounting for these properties and adjusted the fair value of the assets acquired and liabilities assumed from $117.6 million to $117.1 million after applying the corresponding post-closing purchase price adjustments.

The following table summarize the final calculations of the fair values of the assets acquired and liabilities assumed for these properties (in thousands):

	Final	Estimated At December 31, 2014	Change
Fair value of net assets:			
Oil properties	$ 118,906	$ 119,438	$ (532)
Total assets acquired	$ 118,906	$ 119,438	$ (532)
Fair value of net liabilities assumed:			
Asset retirement obligation	1,851	1,851	—
Fair value of net assets acquired	$ 117,055	$ 117,587	$ (532)

Creek County, Oklahoma acquisition

During August 2014, we acquired from our affiliate, Mid-Con Energy III, LLC, a certain oil property located in Creek County, Oklahoma for an aggregate purchase price of approximately $56.5 million. The transaction was primarily funded with borrowings under our revolving credit facility of approximately $4.5 million in cash and the issuance of 2,214,659 common units having an approximate value of $52.0 million.

The final recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

Fair value of net assets:	
Oil property	$ 56,979
Total assets acquired	$ 56,979
Fair value of net liabilities assumed:	
Asset retirement obligation	479
Fair value of net assets acquired	$ 56,500

Liberty County, Texas acquisition

During August 2014, we acquired a waterflood unit in Liberty County, Texas for approximately $18.9 million. The acquisition was financed with borrowings under our revolving credit facility.

Southern Oklahoma acquisition

During May 2014, we acquired additional working interests in some of our Southern Oklahoma core area properties for an aggregate purchase price of approximately $7.3 million. The acquisition was financed with borrowings under our revolving credit facility.

Hugoton acquisition

During February 2014, we acquired from our affiliate, Mid-Con Energy III, LLC, certain oil properties located in Cimarron, Love and Texas Counties, Oklahoma and Potter County, Texas ("Hugoton") for an aggregate purchase price of approximately $41.0 million. The transaction was primarily funded with borrowings under our revolving credit facility of approximately $7.0 million and the issuance of 1,500,000 common units having an approximate value of $34.0 million.

The final recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

Fair value of net assets:		
Oil properties	$	41,589
Total assets acquired	$	41,589
Fair value of net liabilities assumed:		
Asset retirement obligation		589
Fair value of net assets acquired	$	41,000

Other acquisitions

During 2014 we had other various other acquisitions that we paid approximately $0.1 million.

Northeastern Oklahoma acquisition

In May 2013, we acquired additional working interests in our Cushing properties located in the Northeastern Oklahoma core area and in certain Southern Oklahoma units. We paid approximately $27.4 million in aggregate consideration for the interests and the transaction was accounted for under the acquisition method. The transaction was financed using proceeds from our revolving credit facility.

The final recognized fair values of the assets acquired and liabilities assumed in connection with the acquisition are as follows (in thousands):

Fair value of net assets:		
Oil and natural gas properties	$	28,318
Total assets acquired	$	28,318
Fair value of net liabilities assumed:		
Asset retirement obligation		906
Fair value of net assets acquired	$	27,412

The following table reflects pro forma revenues, net income and net income per limited partner unit for the year ended December 31, 2014 and 2013, as if the acquisitions of the Permian properties, Creek County property and Hugoton properties had taken place on January 1, 2013. The table also reflects incremental depreciation, depletion and amortization expense using the unit-of-production method related to the oil and natural gas properties acquired, incremental accretion expense related to asset retirement obligations on the oil and natural gas properties acquired and interest expense related to the incremental debt incurred to fund the acquisitions.

The mid-November and December 2014 values for the Permian properties are reflected in the consolidated statements of operations since we took over operations mid-November. We took over the interests at August 1, 2014 for the Creek County property, therefore the values for August and September 2014 are included in the consolidated statements of operations. We took over the interests at February 28, 2014 for the Hugoton properties, therefore the values for March 2014 through September 2014 are reflected in the consolidated statements of operations. The unaudited pro forma financial data does not include the results of operations for the Liberty County, Texas, Southern Oklahoma or Northeastern Oklahoma properties, as the results of operations were deemed not to be material. These unaudited pro forma amounts do not purport to be indicative of the results that would have actually been obtained during the period presented or that may be obtained in the future (in thousands):

		Year Ended December 31,		
		2014		2013
Revenues	$	168,765	$	131,230
Net income attributable to limited partners	$	39,033	$	45,598
Net income per limited partner unit:				
Basic	$	1.73	$	1.99
Diluted	$	1.73	$	1.99

Note 4. 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, 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, and it is administered by the members of our general partner (the "Founders") and approved by the Board of Directors of the general partner. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and canceled and are no longer considered issued and outstanding.

The Board of Directors of the general partner recommended for approval and, on November 20, 2015, the common unitholders approved an amendment to the Long-Term Incentive Program that increased the number of common units available for issuance under the program from 1,764,000 to 3,514,000 common units.

The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at December 31, 2015:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,113,374)
Restricted units granted, net of forfeitures	(433,857)
Equity-settled phantom units, net of forfeitures	(100,500)
Phantom units issued, net of forfeitures	(22,166)
Awards available for future grant	1,844,103

We recognized \$3.2 million, \$7.7 million and \$6.6 million of total equity-based compensation expense for the years ended December 31, 2015, 2014 and 2013, respectively. These costs are reported as a component of general and administrative expense in our consolidated statements of operations.

Unrestricted awards

During 2015, we granted 274,550 unrestricted units with an average grant date fair value of \$4.85 per unit. We account for unrestricted awards as equity awards since they are settled by issuing common units.

Restricted Awards

We account for restricted awards as equity awards since they will be settled by issuing common units. These units vest over a two or three year period. The compensation expense we recognize associated with our restricted stock is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant.

A summary of our restricted units awarded for the years ended December 31, 2015 and 2014 is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2013	120,589	$ 23.35
Units granted	53,375	$ 23.11
Units vested	(44,430)	$ 23.09
Units forfeited	(19,734)	$ 23.64
Outstanding at December 31, 2014	109,800	$ 23.28
Units granted	294,100	$ 5.04
Units vested	(148,195)	$ 12.43
Units forfeited	(32,872)	$ 9.28
Outstanding at December 31, 2015	222,833	$ 8.49

During 2015, we granted 268,000 restricted common units with one-third vesting immediately and the other two-thirds vesting over two years, with an average grant date fair value of $5.06 per unit. We also granted 26,100 restricted common units with a three year vesting period and average grant date fair value of $4.88 per unit. As of December 31, 2015, there was approximately $0.9 million of unrecognized compensation costs related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.1 years .

Equity-settled phantom awards

In July 2015, we granted 69,000 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years, and 46,500 equity-settled phantom units with a three year vesting period. The equity-settled phantom units do not have any rights or privileges of a common unitholder, including right to distributions, until vesting and the resulting conversion into common units. These equity-settled phantom awards were granted to certain employees of our affiliates and certain directors and founders of our general partner. We account for equity-settled phantom awards as equity awards since they will be settled by issuing common units. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. For the year ended December 31, 2015, we recorded approximately $41,000 of compensation expense.

A summary of our equity-settled phantom units awarded for the year ended December 31, 2015 is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	—	$ —
Units granted	115,500	$ 2.87
Units vested	(23,000)	$ 3.12
Units forfeited	(15,000)	$ 2.81
Outstanding at December 31, 2015	77,500	$ 2.81

As of December 31, 2015, there was approximately $0.2 million of unrecognized compensation costs related to equity-settled phantom units. The cost is expected to be recognized over a weighted average period of approximately 2.0 years.

Phantom awards

We accounted for phantom units issued in July 2013 as a liability award since these awards could have been settled in either cash or common units. The vesting of the phantom units was subject to the attainment of certain production targets during a period of three years. These units were not eligible to receive quarterly distributions. In December 2015, we wrote-off approximately $0.1 million in deferred liability associated with the phantom units since the remaining production targets are not anticipated to be achieved during the specific vesting period.

Note 5. 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 to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and the NYMEX futures prices.

At December 31, 2015 and 2014, our net commodity derivative contracts were in a net asset position with a fair value of approximately $25.6 million and $27.0 million, respectively. All of our commodity derivative contracts are with major financial institutions that are also members of our banking group. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss. During the three years ended December 31, 2015, all of our counterparties have performed pursuant to their commodity derivative contracts.

At December 31, 2015, our commodity derivative contracts had maturities in 2016 and 2017 and were comprised of commodity price swap, call and put contracts. At December 31, 2014, our commodity derivative contracts had maturities in 2015 and 2016 and were comprised of commodity price swap contracts.

For commodity price swap contracts, at the time of execution the seller agrees to receive a fixed price at maturity in exchange for any gains or losses that might be realized from allowing the price of the underlying to float with the market until maturity. From the perspective of the seller, these instruments limit exposure to price declines below the price fixed by the swap at the expense of participating in any price increases above the price fixed by the swap.

For commodity price call contracts, in return for a premium received at execution the seller is obliged to pay the difference, when positive, between the market price of the underlying at maturity less the strike price. From the perspective of the seller, these instruments provide income via the premium received at the expense of any incremental gains that would have otherwise been received above the strike price.

For commodity price put contracts, in return for a premium paid, which can be effected at either execution or settlement, the purchaser has the right to receive the the difference, when positive, between the strike price and the market price of the underlying at maturity. From the perspective of the purchaser, these instruments limit exposure to price declines below the strike price at the expense of premiums paid.

A collar is a combination of a put purchased or sold by a party and a call option sold or purchased by the same party.

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

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

	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2016	$ 79.98			1,598	WTI
Collars - 2016		$ 50.00	$ 50.00	328	WTI
Puts - 2016		$ 50.00	$ —	1,475	WTI
Puts - 2017		$ 50.00	$ —	1,932	WTI

At December 31, 2014, we had the following oil derivative net positions:

Period Covered	Weighted Average Fixed Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2015	$ 93.29	1,932	WTI
Swaps - 2016	$ 90.20	82	WTI

During the first quarter of 2015, we restructured a significant portion of our existing commodity derivative contracts that were in place at December 31, 2014. This resulted in the early settlement of certain contracts existing at December 31, 2014, and entering into new commodity derivative contracts which extend through September 2016. In connection with the early termination and modifications of our commodity derivative contracts, we received net proceeds of approximately $11.1 million from the early termination of contracts on January 22 and 23, 2015, received approximately $5.9 million from selling calls and paid out approximately $19.8 million in premiums to extend the contracts through September 2016. The restructuring also resulted in approximately $4.1 million in deferred premium put options. As of December 31, 2015, we had paid $1.9 million of the deferred put premiums in connection with contract settlements. These transactions provided an additional $23.8 million of cash flow for 2015.

In connection with the November 2015 semi-annual redetermination of our borrowing base, we entered entered into additional commodity derivative contracts resulting in total commodity derivative contracts covering at least 80% of our 2016 projected monthly production and at least 50% of our 2017 projected monthly production. No cash settlements were required and the contracts included deferred premiums of approximately $10.0 million.

Commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our commodity derivative contracts to post collateral, it is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. We evaluate the credit standing of such counterparties by reviewing their credit rating. As of December 31, 2015, the counterparties to our commodity derivative contracts currently in place are lenders under our revolving credit facility and have investment grade ratings.

The following tables summarizes the gross fair value by the appropriate balance sheet classification, even when the commodity derivative contracts are subject to netting arrangements and qualify for net presentation in our consolidated balance sheets at December 31, 2015 and 2014 (in thousands):

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

	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts Presented in the Consolidated Balance Sheet
2014			
Assets			
Derivative financial instruments - current asset	$ 26,202	$ —	$ 26,202
Derivative financial instruments - long-term asset	842	—	842
Total	$ 27,044	$ —	$ 27,044
Liabilities			
Derivative financial instruments - current liability	$ —	$ —	$ —
Derivative financial instruments - long-term liability	—	—	—
Total	$ —	$ —	$ —
Net asset	$ 27,044	$ —	$ 27,044

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

	Year Ended December 31,		
	2015	2014	2013
Net settlements on matured derivatives	$ 28,543	$ 891	$ 288
Net settlements on early terminations and modifications of derivatives	11,069	—	—
Change in fair value of unsettled derivatives, net	(17,246)	28,470	(5,963)
Total gain (loss) on derivatives, net	$ 22,366	$ 29,361	$ (5,675)

Note 6. Fair Value Disclosures

Fair Value of Financial Instruments

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

We account for our commodity derivative contracts at fair value. The fair value of our commodity derivative contracts is determined utilizing NYMEX-WTI closing prices for the contract period.

Fair Value Measurements

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

Assets and liabilities recorded in the balance sheet are categorized based on the inputs to the valuation technique as follows:

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

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

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

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. We had no transfers in or out of Levels 1, 2 or 3 during the years ended December 31, 2015, 2014 and 2013.

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. We use certain pricing models to determine the fair value of our derivative financial instruments. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. See Note 5 in this section for a summary of our derivative financial instruments.

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

We estimate the fair value of 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 7 in this section for a summary of changes in ARO.

We calculate the estimated fair values of reserves and properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and developmental costs; (iii) future commodity prices; (iv) a market-based weighted average cost of capital rate; and (v) the rate at which future cash flows are discounted to estimate present value. We discount future values by a per annum rate of 10% because we believe this amount approximates our long-term cost of capital and accordingly, is well aligned with our internal business decisions. The underlying commodity prices embedded in our estimated cash flows are the product of a process that begins with Level 1 NYMEX WTI forward curve pricing, as well as Level 3 assumptions including: pricing adjustments for estimated location and quality differentials, production costs, capital expenditures, production volumes, decline rates and estimated reserves.

For the years ended December 31, 2015 and 2014, we recorded non-cash impairment charges of approximately $103.9 million and $30.2 million, respectively, associated with proved oil and natural gas properties throughout our core areas reducing the carrying value of certain properties. The impairment was primarily due to a continued decline in commodity prices. The impairment charges are included in "Impairment of proved oil and natural gas properties" in our consolidated statements of operations. In late 2014, prices for oil, natural gas and NGLs declined precipitously and continued to remain low through December 2015. Forward NYMEX WTI price curves have declined from year ended 2014 to 2015.

The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value on a recurring basis as of December 31, 2015 and 2014:

	Level 1	Level 2	Level 3	Fair Value
		(in thousands)		
December 31, 2015				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments- asset	$ —	$ 36,050	$ —	$ 36,050
Derivative financial instruments- liability	—	(514)	—	(514)
Derivative deferred premiums - liability	—	—	(9,973)	(9,973)
Net derivative position	$ —	$ 35,536	$ (9,973)	$ 25,563
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Asset retirement obligations	$ —	$ —	$ 4,924	$ 4,924
Impairment of proved oil and gas properties	$ —	$ —	$ 103,938	$ 103,938
December 31, 2014				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments- asset	$ —	$ 27,044	$ —	$ 27,044
Derivative financial instruments- liability	—	—	—	—
Net derivative position	$ —	$ 27,044	$ —	$ 27,044
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Asset retirement obligations	$ —	$ —	$ 3,171	$ 3,171
Impairment of proved oil and gas properties	$ —	$ —	$ 30,206	$ 30,206

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

	Year Ended December 31,	
	2015	2014
	(in thousands)	
Balance of Level 3 at beginning of period	$ —	$ —
Derivative deferred premiums - purchases	(11,914)	—
Derivative deferred premiums - settlements	1,941	—
Balance of Level 3 at end of period	$ (9,973)	$ —

Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation techniques or related inputs for the years ended December 31, 2015 and 2014.

Note 7. Asset Retirement Obligations

We have obligations under our lease agreements and federal regulations to remove equipment and restore land at the end of oil and natural gas production operations. These asset retirement obligations are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or drilling a well and determine our ARO by calculating the present value of estimated cash flow related to the estimated future liability. Determining the future restoration and removal 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 estimate the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. We are required to record the fair value of a liability for the ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We review our assumptions and estimates of future asset retirement obligations on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. Over time, the liability is accreted each period toward its future value and is recorded in our 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.

Changes in our asset retirement obligations for the periods indicated are presented in the following table:

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Asset retirement obligations - beginning of period	$ 7,363	$ 3,942	$ 2,890
Liabilities incurred for new wells and interest	42	3,171	1,009
Liabilities settled upon plugging and abandoning wells	(40)	—	—
Revision of estimates [1]	4,882	—	(130)
Accretion expense	432	250	173
Asset retirement obligations - end of period	$ 12,679	$ 7,363	$ 3,942

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

As of December 31, 2015 and 2014, all of our ARO were classified as long-term and were reported as "Asset Retirement Obligations" in our consolidated balance sheets.

Note 8. Debt

A summary of our debt for the year ended December 31, 2015 is presented below:

	Year Ended December 31,	
	2015	2014
	(in thousands)	
Revolving credit facility	$ 180,000	$ 205,000
Less: current portion	30,000	—
Total long-term debt	$ 150,000	$ 205,000

At December 31, 2015, we had $180.0 million of borrowings outstanding under our revolving credit facility. Borrowings under the revolving credit facility did not exceed the borrowing base of $187.5 million at December 31, 2015. Borrowings under the facility are secured by liens on not less than 90% of our assets and the assets of our subsidiaries. Our debt consists of $30.0 million classified as current and $150.0 million classified as long-term. At December 31, 2015, maturities of our debt were as follows: $30.0 million in 2016 and $150.0 million in 2018.

The borrowing base of our revolving credit facility is collectively determined by our lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary. The borrowing base is subject to scheduled redeterminations on or about April 30 and October 31 of each year with an additional redetermination, either at our request or at the request of the lender, during the period between each scheduled borrowing base determinations. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of the Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50% and the one month adjusted London Interbank Offered Rate ("LIBOR") plus 1.0% , all of which are subject to a margin that varies from 1.00% to

2.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 2.00% to 3.75% per annum according to the borrowing base usage. For the year ended December 31, 2015, the average effective rate was approximately 3.0% . The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

During April and August 2014, our borrowing base under the revolving credit facility was increased from $150.0 million to $170.0 million and from $170.0 million to $190.0 million, respectively. No other material terms of the original credit agreement were amended. In connection with this amendment to our revolving credit facility, we incurred financing fees and expenses of approximately $0.2 million, which will be amortized over the life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our consolidated statements of operations.

During November 2014, our borrowing base under the revolving credit facility was increased from $190.0 million to $240.0 million. The amendment added MUFG Union Bank, N.A. and Frost Bank as additional lenders. No other material terms of the original credit agreement were amended. In connection with this amendment to our revolving credit facility, we incurred financing fees and expenses of approximately $3.6 million, which will be amortized over the life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our consolidated statements of operations.

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

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

During November 2015, the semi-annual redetermination of our borrowing base and amendment of the underlying revolving credit facility was completed. This redetermination resulted in a borrowing base of $190.0 million, consisting of a $165.0 million conforming tranche to which six monthly commitment reductions of $2.5 million each were mandated through May 2016, and a $25.0 million non-conforming tranche that matures on May 1, 2016. The credit facility amendment also designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. This redetermination also required that by December 10, 2015, we enter into commodity derivative contracts of not less than 80% of our 2016 projected monthly production and not less than 50% of our 2017 projected monthly production. These requirements were satisfied during November 2015 with the execution of additional commodity derivative contracts maturing in 2016 and 2017. As of February 29, 2016, debt has been reduced by $7.0 million, from the December 31, 2015 balance, and the outstanding balance at this date was $173.0 million.

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. In connection with this amendment to our revolving credit facility, we incurred financing fees and expenses of approximately $0.7 million, which will be amortized over the remaining life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our consolidated statements of operations.

The revolving credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and payments, including distributions. If we fail to perform our obligations under these and other covenants, the revolving credit commitments may be terminated and any outstanding indebtedness under the credit agreement, together with accrued interest could be declared immediately due and payable. We were in compliance with these covenants as of and during the year ended December 31, 2015.

Note 9. Commitment and Contingencies

We have a service agreement with Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating will provide certain services to us, our subsidiaries and our general partner, including management, administrative and operations services, which include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for or on our behalf and other expenses allocated by Mid-Con Energy Operating to us.

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

Our general partner has entered into employment agreements with the following named employees of our general partner: Jeffrey R. Olmstead, President and Chief Executive Officer and Charles R. Olmstead, Executive Chairman of the Board of our general partner. The employment agreements provide for a term that commenced on August 1, 2011 and automatically renewed on August 1, 2014 for an additional year, unless earlier terminated, and would continue to automatically renew for one-year terms unless either we or the employee gives written notice of termination at least by February 1st preceding any such August 1st. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities, and authority as the Board of Directors of our general partner may specify from time to time, in roles consistent with such positions that are assigned to him. The agreement stipulates that if there is a change of control, termination of employment with cause or without cause, or death of the executive certain payments will be made to the executive officer. These payments, depending on the reason for termination, currently range from $0.3 million to $0.7 million , including the value of vesting of any outstanding units.

Note 10. Equity

Common Units

At December 31, 2015, the Partnership's equity consisted of 29,724,890 common units, representing approximately 98.8% in limited partnership interest in us. At December 31, 2014, the Partnership’s equity consisted of 29,166,112 common units, representing approximately 98.8% in limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution Agreement (the “Agreement”) to sell, from time to time through or to the Managers (as defined in the Agreement), up to $50.0 million in common units representing limited partner interests. The sales, if any, of common units made under the Agreement will be made by any method permitted by law deemed to be an "at-the-market-offering" as defined in Rule 415 under the Securities Act of 1933, as amended (the "Securities Act"), including without limitation, sales made directly on the NASDAQ, on any other existing trading market for our common units or to or through a market maker. From the period of the original agreement to December 31, 2015, we did not sell any common units.

Cash Distributions

Our partnership agreement requires us to distribute all of our available cash on a quarterly basis. Our available cash is our cash on hand at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs, including cash from working capital borrowings. There is not assurance as to the future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors. Our credit agreement stipulates written consent from our lenders is required in order to reinstate distributions and also prohibits us from making cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution.

Prolonged declines in commodity prices prompted us to suspend cash distributions in an effort to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders. In October 2015 and January 2016, the Board of Directors suspended the quarterly cash distributions for the third and fourth quarter of 2015, respectively. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions.

The following sets forth the distributions we paid during the years ended December 31, 2015 and 2014:

Date Paid	Period Covered	Distribution per Unit	Total Distributions
February 13, 2015	October 1, 2014 - December 31, 2014	$ 0.125	$ 3,752
May 14, 2015	January 1, 2015 - March 31, 2015	$ 0.125	3,752
August 13, 2015	April 1, 2015 - June 30, 2015	$ 0.125	3,762
			$ 11,266
February 14, 2014	October 1, 2013 - December 31, 2013	$ 0.515	$ 10,262
May 15, 2014	January 1, 2014 - March 31, 2014	$ 0.515	11,032
August 11, 2014	April 1, 2014 - June 30, 2014	$ 0.515	11,066
November 14, 2014	July 1, 2014 - September 30, 2014	$ 0.515	12,204
			$ 44,564

Allocations of Net Income (Loss)

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

Note 11. Related Party Transactions

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

Services Agreement

We are party to a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides certain services to us, including management, administrative and operational services. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. During the years ended December 31, 2015, 2014 and 2013, we reimbursed Mid-Con Energy Operating approximately $3.7 million , $3.8 million and $3.6 million , respectively, for direct expenses.

Other Transactions with Related Persons

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are party to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies, or COPAS overhead fee). We and those third parties will also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements.

During February and August, 2014, we acquired from Mid-Con Energy III, LLC, an affiliated company, certain oil properties located in Oklahoma and Texas. The terms of the acquisitions were approved by the Conflicts Committee of the Board of Directors of the General Partner (the "Conflicts Committee"). The Conflicts Committee, which is composed entirely of independent directors, retained independent legal and financial counsel to assist it in evaluating and negotiating the purchase agreements and the acquisitions. The purchase agreements contained representations and warranties, covenants and indemnification provisions that are typical for transactions of this nature and that were made or agreed to, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them.

At December 31, 2015, we had payables to Mid-Con Energy Operating of approximately $0.5 million which is comprised of a joint interest billing payable of approximately $0.1 million and a payable for operating services of approximately $0.4 million . At December 31, 2014, we had payables to Mid-Con Energy Operating of approximately $4.0 million which is comprised of a joint interest billing payable of approximately $3.2 million and a payable for operating services of approximately $0.8 million. These amounts are included in the Accounts payable-related parties in our consolidated balance sheets.

Note 12. Credit Risk

Credit risk relates to the risk of loss resulting from non-performance of non-payment by counterparties under the terms of their contractual obligations, thereby impacting the amount and timing of expected cash flows. Financial instruments which potentially subject us to credit risk consist principally of cash balances, accounts receivable and derivative financial instruments. We maintain cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. We have not experienced any significant losses from such investments. The percentage of revenue derived by customers that accounted for approximately 10% or more of consolidated total revenues is presented below. No other customer accounted for more than 10% of our consolidated total revenues for 2015, 2014 or 2013.

For the year ended December 31, 2015, sales of oil and natural gas to BML, Enterprise and Coffeyville accounted for approximately 31% , 22% and 21% , respectively, of our totals sales revenues. These purchasers represent 32% , 18% and 23% , respectively, of our outstanding oil and natural gas accounts receivable at December 31, 2015.

For the year ended December 31, 2014, sales of oil and natural gas to Enterprise, Coffeyville and Plains Marketing, LP accounted for approximately 40% , 26% and 9% , respectively, of our total sales revenues. These purchasers represent 14% , 25% and 6% , respectively, of our outstanding oil and natural gas accounts receivable at December 31, 2014.

For the year ended December 31, 2013, purchases by Enterprise, Coffeyville and National Cooperative Refinery Association accounted for approximately 50% , 23% and 8% , respectively of our total sales revenues. These purchasers represent 46% , 30% and 10% , respectively, of our outstanding oil and natural gas accounts receivable at December 31, 2013.

We believe that the loss of any one purchaser would not have an adverse effect on our ability to sell its oil and natural gas production because we believe we could sell to other purchasers at market-based prices. We have not experienced any significant losses due to uncollectible accounts receivable from these purchasers.

Note 13. Employee Benefit Plans

In 2011, our general partner adopted the Mid-Con Energy Partners, LP Long-Term Incentive Program which is intended to promote the interests of the partnership by providing to employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating, grants of restricted units, phantom units, unit appreciation rights, distribution equivalent rights and other unit based awards to encourage superior performance, The Long-Term Incentive Program is also intended to enhance the ability of the general partner and our other affiliates, including Mid-Con Energy Operating, to attract and retain the services of individuals who are essential for the growth and profitability of the partnership and to encourage them to devote their best efforts to advancing the business of the partnership.

The Long-Term Incentive Program is currently administered by a committee consisting of the Founders and approved by the Board of Directors. Except as set forth in the employment agreements of the executive officers of our general partner, we have no set formula for granting awards to our employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating. In determining whether to grant awards and the amount of any awards, the committee takes into consideration discretionary factors such as the individual's current and expected future performance, level of responsibility, retention considerations and the total compensation package.

The Board of Directors of the general partner recommended for approval and, on November 20, 2015, the unitholders approved an amendment to the Long-Term Incentive Program that increased the number of common units available for issuance under the program from 1,764,000 to 3,514,000 common units. As of December 31, 2015 there were 1,844,103 units available for issuance.

Note 14. Income Taxes

We do not pay federal income taxes, as our profits or losses are reported to the taxing authorities by our individual partners.

Note 15. Subsequent Events

On January 8, 2016, Nathan P. Pekar resigned from his position as General Counsel, Secretary and Vice President. Beginning January 18, 2016, Mr. Pekar began serving our general partner as a third party consultant.

On January 21, 2016, the Board of Directors of our general partner reaffirmed the suspension of cash distributions for the fourth quarter of 2015.

Also on January 21, 2016, the Board of Directors of our general partner authorized the issuance of 70,000 unrestricted common units, 24,500 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years . The equity-settled phantom units do not have any rights or privileges of a unitholder, including right to distributions, until vesting and the resulting conversion into common units. These units were granted to certain employees of our affiliates and certain directors and founders of our general partner.

As of February 29, 2016, debt has been reduced by $7.0 million from the December 31, 2015 balance, and the outstanding balance was $173.0 million.

Note 16. Supplementary Information

Quarterly data (unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per unit amounts)			
2015				
Oil and natural gas sales	$ 17,571	$ 21,611	$ 18,493	$ 16,239
Gain (loss) on derivatives, net	$ 1,644	$ (8,871)	$ 19,771	$ 9,822
Total revenues and other	$ 19,215	$ 12,740	$ 38,264	$ 26,061
Total expenses (1)	$ 23,327	$ 20,684	$ 63,742	$ 84,022
Net loss	$ (4,112)	$ (7,944)	$ (25,478)	$ (57,961)
Net loss per limited partner unit (basic)	$ (0.14)	$ (0.26)	$ (0.85)	$ (1.93)
Net loss per limited partner unit (diluted)	$ (0.14)	$ (0.26)	$ (0.85)	$ (1.93)
2014				
Oil and natural gas sales	$ 21,807	$ 24,335	$ 26,173	$ 24,596
Gain (loss) on derivatives, net	$ (2,048)	$ (4,891)	$ 9,280	$ 27,020
Total revenues and other	$ 19,759	$ 19,444	$ 35,453	$ 51,616
Total expenses (1)	$ 18,198	$ 15,597	$ 18,451	$ 51,534
Net income	$ 1,561	$ 3,847	$ 17,002	$ 82
Net income per limited partner unit (basic)	$ 0.08	$ 0.18	$ 0.75	$ —
Net income per limited partner unit (diluted)	$ 0.08	$ 0.18	$ 0.74	$ —

(1) Includes the following expenses: lease operating, production taxes, impairment, depreciation, depletion and amortization, accretion, general and administrative and net other expense.

Supplementary oil and natural gas activities

Costs incurred in oil and natural gas property acquisitions and development activities are as follows:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Property acquisition costs:			
Proved	$ 1	$ 241,355	$ 28,057
Unproved	—	—	—
Exploration	—	—	—
Development	13,415	34,320	22,287
Asset retirement obligations	4,924	3,171	879
Total costs incurred	$ 18,340	$ 278,846	$ 51,223

Estimated proved oil and natural gas reserves (unaudited)

The Company's proved oil and natural gas reserves are all located in the United States. The proved oil and natural gas reserves for the years ended December 31, 2015, 2014 and 2013 were prepared by our reservoir engineers and audited by Cawley, Gillespie & Associates, Inc., independent third party petroleum consultants. These reserve estimates have been prepared in compliance with the rules of the SEC. We emphasize that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates are expected to change as future information becomes available.

An analysis of the change in estimated quantities of oil and natural gas reserves are presented below for the periods indicated:

	Oil (MBbls)	Gas (MMcf)	MBoe [(1)]
Proved developed and undeveloped reserves:			
As of December 31, 2012	13,074	429	13,146
Revisions of previous estimates	264	827	401
Extensions, discoveries and other additions	76	—	76
Purchases of minerals in place	1,207	193	1,239
Production	(907)	(128)	(928)
As of December 31, 2013	13,714	1,321	13,934
Revisions of previous estimates	211	924	364
Extensions, discoveries and other additions	1,241	52	1,250
Purchases of minerals in place	8,086	4,402	8,820
Production	(1,112)	(157)	(1,138)
As of December 31, 2014	22,140	6,542	23,230
Revisions of previous estimates [(2)]	596	856	739
Extensions, discoveries and other additions	—	—	—
Purchases of minerals in place	1	—	1
Production	(1,623)	(571)	(1,718)
As of December 31, 2015	21,114	6,827	22,252
Proved developed reserves:			
December 31, 2013	10,397	1,321	10,617
December 31, 2014	17,046	5,327	17,933
December 31, 2015	14,368	4,762	15,162
Proved undeveloped reserves:			
December 31, 2013	3,317	—	3,317
December 31, 2014	5,094	1,215	5,297
December 31, 2015	6,746	2,065	7,090

(1) Estimated quantities of oil and natural gas reserves in MBoe equivalents at a rate of six Mcf per Bbl.
(2) Includes revisions due to price product price changes and added reserves through EOR and infill drilling activities.

Revisions represent changes in the previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

The change in quantities of proved reserves from December 31, 2012 to December 31, 2013 is due to the acquisitions of additional interests in our Southern Oklahoma units and Northeastern Oklahoma properties and revisions on prior estimates. For this period, proved reserve volumes attributed to extensions, discoveries and other additions changed from 1,572 MBoe in 2012 to 76 MBoe in 2013. During the period of 2013, there were no significant extensions, discoveries, or other additions except for a small extension in the Hugoton area in our Clawson Ranch waterflood unit due to drilling activity extending the proved reservoir acreage. This is in contrast to the 2012 period, where drilling in our Southern Oklahoma waterflood units extended the proved acreage while recompletion activities in our Northeast Oklahoma properties added proved reserves in new reservoirs in old fields resulting in substantial extensions, discoveries and other additions.

The change in quantities of proved reserves from December 31, 2013 to December 31, 2014 is due to (i) the acquisitions of additional properties in Oklahoma and Texas from our affiliate Mid-Con Energy III, LLC; (ii) the acquisition of additional working interest in some of our Southern Oklahoma properties; (iii) the acquisition of the waterflood unit in Liberty County, Texas; and (iv) the acquisition of multiple properties located in West Texas within the Eastern Shelf of the Permian. For this period, proved reserve volumes attributed to extensions, discoveries and other additions changed from 76 MBoe in 2013 to

1,250 MBoe in 2014. During the period of 2014, extensions, discoveries and other additions increased over the prior year primarily from development work in the Northeast Oklahoma area, which increased proved developed producing and proved undeveloped reserves from new reservoirs from portions of older fields.

The change in quantities of proved reserves from December 31, 2014 to December 31, 2015 is due to (i) a significant commodity price decrease that resulted in a downward revision of 4,084 MBoe, (ii) improved recovery of 1,417 MBoe from our proved developed reserves in addition to 994 MBoe transferred from proved undeveloped reserves to proved developed reserves, and (iii) the addition of recompletions, infill drilling, new waterflood projects, and expansion of existing waterflood projects in our Hugoton, Northeast Oklahoma, Southern Oklahoma and Permian core areas resulting in a positive revision of proved undeveloped reserves of 3,405 MBoe. The upward revision of our proved developed reserves is largely attributable to a positive oil production response in 2015 to recently established water injection in the Cleveland Unit (Northeast Oklahoma), Ona Morrow Unit (Hugoton) and Midwell Unit (Hugoton).

Estimates of economically recoverable oil and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil and natural gas may differ materially from the amounts estimated.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves (Unaudited)

The standardized measure represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, production, plugging and abandonment costs, discounted at the rate prescribed by the SEC. The standardized measure of discounted future net cash flow does not purport to be, nor should it be interpreted to represent, the fair market value of our proved oil and natural gas reserves. The following assumptions have been made:

- In the determination of future cash inflows, sales prices used for oil and natural gas for the years ended December 31, 2015, 2014 and 2013, were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month in such period.
- Future costs of developing and producing the proved oil and natural gas reserves were based on costs determined at each such period-end, assuming the continuation of existing economic conditions, including abandonment costs.
- No future income tax expenses are computed for Mid-Con Energy Partners, LP because we are a non-taxable entity.
- Future net cash flows were discounted at an annual rate of 10% .

The standardized measure of discounted future net cash flow relating to estimated proved oil and natural gas reserves is presented below for the periods indicated:

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Future cash inflows	$ 1,011,096	$ 2,084,005	$ 1,295,435
Future production costs	(581,314)	(825,318)	(542,389)
Future development costs, including abandonment costs	(109,669)	(76,783)	(49,458)
Future net cash flow	320,113	1,181,904	703,588
10% discount for estimated timing of cash flow	(128,693)	(517,627)	(312,325)
Standardized measure of discounted cash flow	$ 191,420	$ 664,277	$ 391,263

The prices utilized in calculating our total proved reserves were $50.28 , $94.99 and $96.78 per Bbl of oil and $2.58 , $4.35 and $3.67 per MMBtu of natural gas for December 31, 2015, 2014 and 2013, respectively. These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions or other factors affecting the price received at the wellhead. Average adjusted prices used were $47.23 , $92.45 and $93.98 per Bbl of oil and $2.02 , $5.67 and $5.00 per Mcf of natural gas for December 31, 2015, 2014 and 2013, respectively. Adjusted natural gas price includes the sale of associated natural gas liquids. All wellhead prices are held flat over the life of the properties for all reserve categories.

Changes in the standardized measure of discounted future net cash flow relating to proved oil and natural gas reserves is presented below for the periods indicated:

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Standardized measure of discounted future net cash flow, beginning of period	$ 664,277	$ 391,263	$ 403,422
Changes in the year resulting from:			
Sales, less production costs	(36,836)	(64,495)	(65,553)
Revisions of previous quantity estimates	8,047	11,712	12,006
Extensions, discoveries and improved recovery	—	44,727	1,863
Net change in prices and production costs	(454,669)	22,068	(28,324)
Net change in income taxes	—	—	—
Changes in estimated future development costs	(6,080)	(18,125)	(17,155)
Previously estimated development costs incurred during the period	8,103	22,526	22,257
Purchases of minerals in place	19	264,921	38,170
Accretion of discount	66,428	39,126	40,342
Timing differences and other	(57,869)	(49,446)	(15,765)
Standardized measure of discounted future net cash flow, end of year	$ 191,420	$ 664,277	$ 391,263

ITEM 9. CHANGES IN AND DISAGREEMETS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 December 31, 2015. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on this evaluation, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Form 10-K.

Management's Report on Internal Control over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our internal control system was designed to provide reasonable assurance to our Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway

Commission. Based on this evaluation, management concluded that Mid-Con Energy Partners, LP's internal control over financial reporting was effective as of December 31, 2015.

/s/ Jeffrey R. Olmstead	/s/ Michael D. Peterson
Jeffrey R. Olmstead Chief Executive Officer	Michael D. Peterson Chief Financial Officer

February 29, 2016

As a company with less than $1.0 billion in revenue during its last fiscal year, we qualify as an "emerging growth company" as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. As an emerging growth company we may take advantage of specified reduced reporting and other regulatory requirements for up to five years that are otherwise applicable generally to public companies. As an emerging growth company we are taking the exemption from the auditor attestation requirement on the effectiveness of our system of internal control over financial reporting.

Change 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 period covered by this Form 10-K 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.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

As is the case with many publicly traded partnerships, we do not directly employ officers, directors or employees. Our operations and activities are managed by our general partner. References to our officers and Board of Directors therefore refer to the officers and Board of Directors of our general partner. Our general partner is owned and controlled by the Founders.

Our general partner is not elected by our unitholders and is not subject to re-election on an annual or other continuing basis in the future. In addition, our unitholders are not entitled to elect the directors of our general partner, nor are they directly or indirectly entitled to participate in our management or operations. Further, our partnership agreement, like many master limited partnership agreements, contains provisions that substantially restrict the fiduciary duties that our general partner would otherwise owe to our unitholders under Delaware law.

The Board of Directors of our general partner has eight members. The NASDAQ listing rules do not require a listed limited partnership like us to have a majority of independent directors on the Board of Directors of our general partner or to establish a compensation committee or a nominating and corporate governance committee. We are, however, required to have an audit committee of at least three members, all of whom are required to meet the independence and experience standards established by the NASDAQ listing rules and SEC rules.

All of the executive officers of our general partner are also officers and/or directors of Mid-Con Affiliates. The executive officers of our general partner allocate their time between managing our business and affairs and the business and affairs of Mid-Con Affiliates. In addition, employees of Mid-Con Energy Operating provide management, administrative and operational services to us pursuant to the services agreement, but they also provide these services to Mid-Con Affiliates.

Directors and Executive Officers

The following table sets forth certain information regarding the current directors and executive officers of our general partner. At December 31, 2015, the average tenure of the individuals listed below is 3 years and 10 months since the Initial Public Offering in December 2011.

Name	Age	Position with Mid-Con Energy GP, LLC
Charles R. "Randy" Olmstead	67	Executive Chairman of the Board
Jeffrey R. Olmstead	39	President, Chief Executive Officer and Director
Michael D. Peterson	44	Vice President and Chief Financial Officer
Nathan P. Pekar	40	Vice President, General Counsel and Secretary
Sherry L. Morgan	48	Chief Accounting Officer
S. Craig George	63	Director
Peter A. Leidel	59	Director
Cameron O. Smith (1)	65	Director
Robert W. Berry (1)	92	Director
Peter Adamson III (1)	74	Director
C. Fred Ball Jr. (2)	71	Director

(1) Member of the audit committee and the conflicts committee.
(2) Member of the audit committee.

The members of our general partner's Board of Directors are appointed for one-year terms by the Founders and hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been appointed and qualified. The executive officers of our general partner serve at the discretion of the Board of Directors. All of our general partner's executive officers also serve as executive officers of the Mid-Con Affiliate. Charles R. Olmstead and Jeffrey R. Olmstead are father and son, respectively. There are no other family relationships among our general partner's executive officers and directors.

Charles R. "Randy" Olmstead serves as Executive Chairman of the Board of Directors of our general partner. Mr. Olmstead previously served as Chief Executive Officer and Chairman of the Board of Directors of our general partner and Mid-Con Energy III, LLC from June 2011 until August 2014. Mr. Olmstead served as President, Chief Financial Officer and Chairman of the Board of Directors of Mid-Con Energy I, LLC from its formation in 2004 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. He has been President, Chief Financial Officer and Chairman of the Board of Directors of Mid-Con Energy Operating since its incorporation in 1986. Prior to that, Mr. Olmstead was general manager for LB Jackson Drilling Company from 1978 to 1980 and worked in public accounting for Touche Ross & Co. from 1974 to 1978 as an oil and gas tax consultant. Mr. Olmstead graduated with Bachelors of Business Administration degrees in finance and accounting from the University of Oklahoma before serving three years in the US Navy. Mr. Olmstead brings to our Board of Directors extensive management and operational experience in the oil and gas industry, along with his leadership skills.

Jeffrey R. Olmstead serves as President, Chief Executive Officer and as a member of the Board of Directors of our general partner. Mr. Olmstead previously served as President, Chief Financial Officer of our general partner and Mid-Con Energy III, LLC from June 2011 until August 2014. Mr. Olmstead was a member of the Board of Directors of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC from 2007 until both entities were merged into us in December 2011. Mr. Olmstead previously served as Chief Financial Officer and Vice President of Primexx Energy Partners, Ltd., a privately held exploration and production company, from May 2010 until July 2011. From August 2006 until May 2010, Mr. Olmstead served as an Assistant Vice President at Bank of Texas/Bank of Oklahoma. Mr. Olmstead holds a Bachelor of Engineering degree in Electrical Engineering and Math from Vanderbilt University and a Master of Business Administration from the Owen School of Business at Vanderbilt University. Mr. Olmstead brings to our Board of Directors knowledge of the oil and gas industry and his finance background provides a critical resource.

Michael D. Peterson serves as Vice President and Chief Financial Officer of our general partner. Mr. Peterson became an officer of our general partner in March 2014. Prior to joining us, Mr. Peterson was employed as Managing Director and Head of Energy Research at MLV & Co., where he covered Master Limited Partnerships from 2012 to 2014. Mr. Peterson was employed as Managing Director, Energy Research with International Strategy & Investment Group ("ISI"), covering Integrated Oil and Refining equities from 2009-2011. Prior to ISI, Mr. Peterson was employed as an Energy Research Analyst, where he covered Integrated Oil, Refining and Exploration & Production equities with Morgan Stanley from 2007 to 2009 and with SunTrust Robinson Humphrey from 2006 to 2007. Mr. Peterson was employed as a Commodities Trader from 1999 to 2006 and as a Sr. Risk Management Analyst from 1998 to 1999 with Duke Energy. Mr. Peterson holds a Bachelor of Arts degree in Political Science and Economics from the University of Denver, a Master of Science degree in Financial Markets & Trading from the Stuart School of Business at the Illinois Institute of Technology and a Master of Business Administration from the Booth School of Business at the University of Chicago.

Nathan P. Pekar serves as Vice President of Business Development, General Counsel and Secretary of our general partner. Mr. Pekar became an officer of our general partner in April 2012. Prior to joining us, Mr. Pekar served as General Counsel and Business Development Manager with Matador Resources Company from 2007 to 2012. Prior to this, Mr. Pekar was in private practice from 2003 to 2007. Mr. Pekar graduated with a Bachelor of Business Administration degree in Finance from the University of Texas at Austin and holds a Juris Doctor degree from Southern Methodist University School of Law. He is a licensed attorney in the State of Texas. On January 8, 2016, Nathan P. Pekar resigned from his position as General Counsel, Secretary and Vice President. Beginning January 18, 2016, Mr. Pekar began serving the general partner as a third party consultant.

Sherry L. Morgan serves as Chief Accounting Officer of our general partner. Ms. Morgan became an officer of our general partner in July 2015, and previously served as our Assistant Controller from July 2008 until July 2015. Prior to joining us, Ms. Morgan served as Controller at Shamrock Oil & Gas, Inc. from 2006 to 2008. She also served as Controller for Nadel and Gussman, LLC during 2006. Ms. Morgan served as Reporting and Joint Interest Coordinator at Newfield Exploration Mid-Continent, Inc. from 2000-2005. Previously she was Assistant Controller at Lariat and First Credit Solutions. Ms. Morgan began her career as an auditor at Deloitte and Touche LLP. Ms. Morgan earned her Bachelor of Science in Business Administration in accounting from Oklahoma State University. She is a Certified Public Accountant and a Certified Management Accountant.

S. Craig George serves as a member of the Board of Directors of our general partner. Mr. George was previously the Executive Chairman of the Board of Directors from July 2011 until August 2014. Mr. George has been a member of the Board of Directors of Mid-Con Energy III, LLC and Mid-Con Energy Operating since June 2011. Mr. George was a member of the Board of Directors of Mid-Con Energy I, LLC and Mid-Con Energy Operating since 2004 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. From 1991 to 2004, Mr. George served in various executive positions at Vintage Petroleum, Inc., including President, Chief Executive Officer and as a member of the Board of Directors. In 1981, Mr. George joined Santa Fe Minerals, Inc. where he served until 1991 in executive positions including Vice President of Domestic Operations and Vice President-International. From 1975 to 1981, Mr. George held engineering and management positions with Amoco Production Company. Mr. George holds a Bachelor of Science degree in Mechanical Engineering from Missouri University of Science and Technology and a Master of Arts in Theology from Aquinas Institute. Over the course of his lengthy career in the oil and gas industry, Mr. George brings to our Board of Directors extensive management and operational experience and a strong record of leadership, strategic vision and risk management.

Peter A. Leidel serves as a member of the Board of Directors of our general partner. Mr. Leidel is a founder and principal of Yorktown Partners LLC, which was established in September 1990. Yorktown Partners LLC is the manager of private investment partnerships that invest in the energy industry. Mr. Leidel has been a member of the Board of Directors of Mid-Con Energy III, LLC and Mid-Con Energy Operating since June 2011. Mr. Leidel was a member of the Board of Directors of Mid-Con Energy I, LLC from its formation in 2004 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. Previously, he was a partner of Dillon, Read & Co. Inc., held corporate treasury positions at Mobil Corporation worked for KPMG and for the U.S. Patent and Trademark Office. Mr. Leidel is a director of certain non-public companies in the energy industry in which Yorktown holds equity interests. Mr. Leidel earned a Bachelor of Business Administration degree in accounting from the University of Wisconsin and a Master of Business Administration from the Wharton School at the University of Pennsylvania. Mr. Leidel brings to our Board of Directors extensive private experience within and perspective on the energy sector.

Cameron O. Smith serves as a member of the Board of Directors of our general partner and is also chairman of the conflicts committee. Mr. Smith founded and from 1992 to 2008, served as a Senior Managing Director of COSCO Capital Management LLC, an investment bank focused on private oil and gas corporate and project financing until Rodman & Renshaw, LLC, a full service investment bank, purchased the business and assets of COSCO Capital Management LLC. From 2008 until December 2009, Mr. Smith served as a Senior Managing Director of Rodman & Renshaw, LLC and as Head of The Rodman Energy Group, a sector vertical within Rodman & Renshaw, LLC. Mr. Smith retired from The Rodman Energy Group in December 2009. Mr. Smith founded and ran Taconic Petroleum Corporation, an exploration company headquartered in Tulsa, Oklahoma from 1978 to 1991. Mr. Smith served as exploration geologist, officer and director of several private family and public client companies from 1975 to 1985. Mr. Smith graduated with an A.B. in Art History from Princeton University and a Master of Science in Geology from Pennsylvania State University. Mr. Smith brings to our Board of Directors extensive knowledge of the oil and natural gas industry, along with expertise in investment banking.

Robert W. Berry serves as a member of the Board of Directors of our general partner. Mr. Berry is founder, Chief Executive Officer and President of Robert W. Berry, Inc., Empress Gas Corp. Ltd., R.W. Berry Canada, Inc. and Berry Ventures, Inc. which produce oil and gas in Oklahoma, Texas, Arkansas, North Dakota and Canada, and has served in these positions for more than the past five years. Mr. Berry has drilled and discovered numerous oil fields in Texas, North Dakota and Canada since working for Amerada Petroleum Corporation as a geologist. Mr. Berry graduated with a Bachelor of Science degree in Geology from the University of Oklahoma. Mr. Berry brings to our Board of Directors technical knowledge and experience garnered over the last 60 years in the oil and natural gas business.

Peter Adamson III serves as a member of the Board of Directors of our general partner and is also chairman of the audit committee. Mr. Adamson is currently managing member of Autumn Glory Partners, LLC, a private consulting firm. Prior to Autumn Glory Partners, LLC, Mr. Adamson was a founder of Adams Hall Asset Management LLC, a Tulsa, Oklahoma based registered investment advisor with over $1 billion under management and remains a consultant. Prior to forming Adams Hall in 1997, Mr. Adamson was an owner and principal of Houchin, Adamson & Co., Inc., a registered broker-dealer formed in 1980. Mr. Adamson is founding co-investor and advisor to Horizon Well Logging, a leading provider of geological field services. Mr. Adamson serves on the advisory board of the Michel F. Price College of Business at the University of Oklahoma and serves on the University of Oklahoma asset oversight committee. Mr. Adamson received his Bachelor of Business Administration degree in accounting from the University of Oklahoma. Mr. Adamson brings to our Board of Directors a breadth knowledge across the disciplines of finance and accounting.

C. Fred Ball, Jr. serves as a member of the Board of Directors of our general partner. Mr. Ball also currently serves as Chief Operating Officer of Spyglass Trading, LP. Mr. Ball retired in January 2015 as Senior Chairman of the Board for Bank of Texas, a division of BOK Financial Corporation. During his 17 year tenure at Bank of Texas, Mr. Ball has been elected to various executive positions including President, Chief Executive Officer and Chairman. Prior to Bank of Texas, he served as President of Comerica Securities, Inc., a subsidiary of Comerica Incorporated in Detroit. Mr. Ball currently serves on the Board of Directors for BOK Financial Corporation, the National Teachers Associates Life Insurance Company, where he is also a member of the audit committee, and at Southern Methodist University, where he resides on both the Executive Board of the Edwin L. Cox School of Business and the Executive Board of the Lyle School of Engineering. Mr. Ball earned his Bachelor of Science in Engineering and Master of Business Administration from Southern Methodist University. Mr. Ball brings to our Board of Directors extensive insights and the knowledge of finance and banking.

Committees of the Board of Directors

Mid-Con Energy GP, LLC's Board of Directors has an audit committee and a conflicts committee. We do not have a compensation committee. The NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee. Our Board of Directors or an appointed committee, currently comprised of the Founders, approve equity grants to directors and employees.

Audit Committee

The audit committee consists of Messrs. Adamson, Ball, Berry and Smith, with Mr. Adamson serving as committee chairman. Our Board of Directors have affirmatively determined that each member of the audit committee meets the independence and experience standards established by the NASDAQ listing rules and the rules of the SEC. Our Board of Directors has also reviewed the financial expertise of Mr. Adamson and affirmatively determined that he is an "audit committee financial expert," as determined by the rules of the SEC. Our Board of Directors has adopted a written charter for our audit committee which is available on and may be printed from our website at www.midconenergypartners.com and is also available from the secretary of Mid-Con Energy GP, LLC.

The audit committee held six meetings in 2015. The audit committee assists the Board of Directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management, as necessary.

Conflicts Committee

The conflicts committee consists of Messrs. Berry, Smith and Adamson, all of whom meet the independence standards established by the NASDAQ listing rules and rules of the SEC. The conflicts committee has the authority to review specific matters that may present a conflict of interest in order to determine if the resolution of such conflict is “fair and reasonable” for our unitholders. In making such determination, the conflicts committee has the authority to engage advisors to assist it in carrying its duties. The conflicts committee did not hold any meetings in 2015.

Board Leadership Structure and Role in Risk Oversight

Leadership of our general partner's Board of Directors is vested in a Chairman of the Board. Although our Chief Executive Officer currently does not serve as Chairman of the Board of Directors of our general partner, we currently have no policy prohibiting our current or any future chief executive officer from serving as Chairman of the Board. The Board of Directors, in recognizing the importance of its ability to operate independently, determined that separating the roles of Chairman of the Board and Chief Executive Officer is advantageous for us and our unitholders at this time. Our general partner's Board of Directors has also determined that having the Chief Executive Officer serve as a director will enhance understanding and communication between management and the Board of Directors, allows for better comprehension and evaluation of our operations and ultimately improves the ability of the Board of Directors to perform its oversight role.

The management of enterprise-level risk is the process of identifying, managing and monitoring of events that present opportunities and risks with respect to the creation of value for our unitholders. The Board of Directors of our general partner has delegated to management the primary responsibility for enterprise-level risk management, while retaining responsibility for oversight of our executive officers in that regard. Our executive officers offer an enterprise-level risk assessment to the Board of Directors at least once every year.

Non-Management Executive Sessions and Unitholder Communications

NASDAQ listing standards require regular executive sessions of the non-management directors of a listed company, and an executive session for independent directors at least once a year. At each quarterly meeting of our general partner's Board of Directors, all of the directors meet in an executive session. At least annually, our independent directors meet in an additional executive session without management participation or participation by non-independent directors.

Interested parties can communicate directly with non-management directors by mail in care of Mid-Con Energy Partners, LP, 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Meetings and Other Information

The Board of Directors held six meetings in 2015.

Our partnership agreement provides that the general partner manages and operates us and that, unlike holders of common stock in a corporation, unitholders only have limited voting rights on matters affecting our business or governance. Accordingly, we do not hold annual meetings of unitholders.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers and directors of our general partner and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and the NASDAQ concerning their beneficial ownership of such securities. Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of our general partner, we believe that all filing requirements applicable to the officers and directors of our general partner and greater than 10% unitholders were complied with for the fiscal year ended December 31, 2015.

Code of Ethics

The governance of Mid-Con Energy GP, LLC is, in effect, the governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Mid-Con Energy GP, LLC has adopted a Code of Business Conduct that applies to all officers, directors and employees of Mid-Con Energy GP, LLC and its affiliates. A copy of our Code of Business Conduct is available on our website at www.midconenergypartners.com . We will provide a copy of our code of ethics to any person, without charge, upon request to Mid-Con Energy GP, LLC, 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201, Attn: Investor Relations.

Web Access

We provide access through our website at www.midconenergypartners.com to current information relating to partnership governance, including our Audit Committee Charter, our Code of Business Conduct and other matters impacting our governance principles. You may access copies of each of these documents from our website. You may also contact the office of the secretary of our general partner for printed copies of these documents free of charge. Our website and any contents thereof are not incorporated by reference into this document.

Communication with Directors

Our Board of Directors believes that it is management's role to speak for the partnership. Our Board of Directors also believes that any communications between members of the Board of Directors and interested parties, including unitholders, should be conducted with the knowledge of our executive chairman, president and chief executive officer. Interested parties, including unitholders, may contact one or more members of our Board of Directors, including non-management directors and non-management directors as a group, by writing to the director or directors in care of the secretary of our general partner at our principal executive offices. A communication received from an interested party or unitholder will be promptly forwarded to the director or directors to whom the communication is addressed. A copy of the communication will also be provided to our executive chairman and chief executive officer. We will not, however, forward sales or marketing materials or correspondence primarily commercial in nature, materials that are abusive, threatening or otherwise inappropriate, or correspondence not clearly identified as interested party or unitholder correspondence.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General

We do not directly employ any of the persons responsible for managing our business. Our general partner's executive officers manage and operate our business as part of the services provided by Mid-Con Energy Operating to our general partner under the services agreement. All of our general partner's executive officers and other employees necessary to operate our business are employed and compensated by Mid-Con Energy Operating, subject to reimbursement by our general partner. The compensation for all of our executive officers is indirectly paid by us to the extent provided for in the partnership agreement because we reimburse our general partner for payments it makes to Mid-Con Energy Operating.

Compensation Committee Report

The NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee, and we do not have a compensation committee. The Board of Directors of our general partner performs the functions of a compensation committee, and although the Board of Directors of our general partner does not currently appoint a compensation committee, it may do so in the future.

The Board of Directors of our general partner has reviewed and discussed with management the Compensation Discussion and Analysis, or CD&A, set forth below.

Our "named executive officers" for the year ended December 31, 2015 were:

Charles R. "Randy" Olmstead
Jeffrey R. Olmstead
Michael D. Peterson
Nathan P. Pekar
Sherry L. Morgan
Michael L. Wiggins

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this Annual Report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

Objectives of Our Compensation Program

Our executive compensation program is intended to align the interests of our management team with those of our unitholders by motivating our executive officers to achieve strong financial and operating results for us, which we believe closely correlate to long-term unitholder value. In addition, our program is designed to achieve the following objectives:

- attract, retain and reward talented executive officers by providing total compensation competitive with that of other executive officers employed by exploration and production companies and publicly traded partnerships of similar size;
- provide performance-based compensation that balances rewards for short-term and long-term results and is tied to both individual and our performance; and
- encourage the long-term commitment of our executive officers to us and our unitholders' long-term interests.

Elements of Our Compensation Program and Why We Pay Each Element

To accomplish our objectives, we seek to offer a compensation program to our executive officers that, when valued in its entirety, serves to attract, motivate and retain executives with the character and expertise required for our growth and development. Our compensation program is comprised of four elements:

- base salary;
- discretionary cash bonus;
- long-term equity-based compensation; and
- benefits.

The Founders, as the controlling members of our general partner, have responsibility and authority for compensation-related decisions for our Chief Executive Officer and, upon consultation and recommendations by our Chief Executive Officer, for our other executive officers. Equity grants pursuant to our long-term incentive program are also administered by the Founders.

Our general partner also grants equity-based awards to our executive officers pursuant to a long-term incentive program described below. Incentive compensation in respect of services provided to us is not tied in any way to the performance of entities other than our partnership. Specifically, any performance metrics are not to be tied in any way to the performance of the Mid-Con Affiliates or any other affiliate of ours.

Although we bear an allocated portion of Mid-Con Energy Operating's costs of providing compensation and benefits to Mid-Con Energy Operating employees who serve as the executive officers of our general partner and provide services to us, we have no control over such costs and do not establish or direct the compensation policies or practices of Mid-Con Energy Operating.

Mid-Con Energy Operating does not maintain a defined benefit or pension plan for its executive officers or employees because it believes such plans primarily reward longevity rather than performance. Mid-Con Energy Operating provides a basic benefits package to all its employees, which includes a 401(k) plan and health, and basic term life insurance, and personal accident and long-term disability coverage. Employees provided to us under the services agreement will be entitled to the same basic benefits.

Employment Agreements

Our general partner has entered into employment agreements with Jeffrey R. Olmstead, Chief Executive Officer and Charles R. Olmstead, Executive Chairman of the Board of our general partner, employees of our general partner. The previous employment agreement with S. Craig George was terminated in August 2014.

The employment agreements provide for a term that commences on August 1 of each year with automatic one-year renewal terms unless either we or the employee gives written notice of termination at least by February 1 preceding any such August 1. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities, and authority as the Board of Directors of our general partner may specify from time to time, in roles consistent with such positions that are assigned to him.

The employment agreements also provide for customary confidentiality, non-solicitation, non-compete and indemnification protections. The non-solicitation provisions prohibit an executive from soliciting persons to leave our employment who are employed by us within six months before or after the executive's termination. This restriction continues during the term of and for twelve months following termination of the executive's employment, and also for twelve months following the termination of the solicited employee's employment. The non-solicitation provisions also prohibit an executive from soliciting our customers during the term of and for twelve months following termination of the executive's employment. The non-competition provisions prohibit the executive from competing with us during the term of the executive's employment and for a period during which severance payments are being made to the executive, which by the terms of the agreements may be up to two years after the executive's separation of employment.

Long-Term Incentive Program

Our Long-Term Incentive Program which is intended to promote the interests of the partnership by providing to employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating, grants of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, and other unit based awards to encourage superior performance. The Long-Term Incentive Program is also intended to enhance the ability of the general partner and our other affiliates, including Mid-Con Energy Operating, to attract and retain the services of individuals who are essential for the growth and profitability of the partnership and to encourage them to devote their best efforts to advancing the business of the partnership.

The Long-Term Incentive Program is currently administered by a committee consisting of the Founders and approved by the Board of Directors. Except as set forth in the employment agreements of the executive officers of our general partner, we have no set formula for granting awards to our employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating. In determining whether to grant awards and the amount of any awards, the committee takes into consideration discretionary factors such as the individual's current and expected future performance, level of responsibility, retention considerations and the total compensation package.

The type of awards that may be granted under the Long-Term Incentive Program are restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The maximum number of our common units that are currently authorized to be awarded under the Plan is 3,514,000 units. As of December 31, 2015 there were 1,844,103 units available for issuance.

Equity Compensation Plan Information:

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**Weighted-average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))**
	(a)	(b)	(c)
Equity compensation plans approved by security holders	—	—	1,844,103 (1)
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	1,844,103

(1) Represents common units.

The plan administrator may terminate or amend the Plan at any time with respect to any units for which a grant has not yet been made. The plan administrator also has the right to alter or amend the Plan or any part of the Plan from time to time, including increasing the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the rights or benefits of the participant without the consent of the participant. The Plan will expire on the earliest to occur of (i) the date on which all common units available under the Plan for grants have been paid to participants, (ii) termination of the Plan by the plan administrator or (iii) December 20, 2021.

Upon a "change of control" (as defined in the Plan), any change in applicable law or regulation affecting the Plan or awards thereunder, or any change in accounting principles affecting the financial statements of our general partner, the plan administrator, in an attempt to prevent dilution or enlargement of any benefits available under the Plan may, in its discretion, provide that awards will (i) become exercisable or payable, as applicable, (ii) be exchanged for cash, (iii) be replaced with other rights or property selected by the plan administrator, (iv) be assumed by the successor or survivor entity or be exchanged for similar options, rights or awards covering the equity of such successor or survivor, or a parent or subsidiary thereof, with other appropriate adjustments or (v) be terminated. Additionally, the plan administrator may also, in its discretion, make adjustments to the terms and conditions, vesting and performance criteria and the number and type of common units, other securities or property subject to outstanding awards.

The consequences of the termination of a grantee's employment, consulting arrangement or membership on the Board of Directors will be determined by the plan administrator in the terms of the relevant award agreement or employment agreement.

Common units to be delivered pursuant to awards under the Plan may be common units already owned by our general partner or us or acquired by our general partner in the open market from any other person, directly from us or any combination of the foregoing. If we issue new common units upon the grant, vesting or payment of awards under the Plan, the total number of common units outstanding will increase, and our general partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash, our general partner will be entitled to reimbursement by us for the amount of the cash settlement.

Short-Term Incentive Payments

The performance criteria for the short-term incentive plan for 2015 and future years include 50% of the target bonus earned for meeting initial quarterly distribution goals, 20% earned for generating an increase in the amount of distributions from the preceding year, 20% earned for generating additions of new reserves and growth of distributions based on aggregate acquisitions of 10% growth, and 10% earned for overall performance as determined by our board. We do not provide perquisites to the named executive officers.

Summary Compensation Table

The following table sets forth certain information with respect to compensation of our named executive officers for services rendered in all capacities to us and our subsidiaries for the years ended December 31, 2015, 2014 and 2013. All of these employees are paid by Mid-Con Energy Operating. We reimburse Mid-Con Energy Operating for a portion of their compensation according to the services agreement entered between us and Mid-Con Energy Operating.

Name and Principal Position	Year	Salary	Bonus	Unit Awards	Total
Charles R. Olmstead	2015	$ 156,006	$ —	$ 524,000	$ 680,006
Executive Chairman of the Board	2014	$ 191,540	$ 201,670	$ 1,273,120	$ 1,666,330
	2013	$ 185,489	$ 266,210	$ 1,120,500	$ 1,572,199
Jeffrey R. Olmstead	2015	$ 315,000	$ —	$ 524,000	$ 839,000
Chief Executive Officer	2014	$ 356,101	$ 269,000	$ 1,273,120	$ 1,898,221
	2013	$ 328,264	$ 297,935	$ 1,120,500	$ 1,746,699
Michael D. Peterson (1)	2015	$ 200,000	$ 56,000	$ 77,580	$ 333,580
Vice President, Chief Financial Officer	2014	$ 108,584	$ 20,000	$ 71,688	$ 200,272
Nathan P. Pekar	2015	$ 162,506	$ 18,000	$ 60,720	$ 241,226
Vice President, General Counsel	2014	$ 183,106	$ 16,668	$ 116,800	$ 316,574
	2013	$ 184,099	$ 81,974	$ 89,640	$ 355,713
Sherry L. Morgan (2)	2015	$ 100,556	$ 18,000	$ 15,180	$ 133,736
Chief Accounting Officer					
Michael L. Wiggins (3)	2015	$ 54,688	$ —	$ 206,250	$ 260,938
President, Chief Engineer	2014	$ 135,704	$ 5,000	$ 577,700	$ 718,404
	2013	$ 131,909	$ —	$ 248,900	$ 380,809

(1) Mr. Peterson joined the company in 2014.
(2) Ms. Morgan became Chief Accounting Officer during 2015.
(3) Mr. Wiggins resigned effective July 1, 2015.

Grants of Plan-Based Awards

The following table sets forth certain information with respect to grants of plan-based awards to our named executive officers in 2015. There were no grants of non-equity incentives or option awards:

Name	Grant Date	Unit Awards		Grant Date Fair Value of Unit Awards	
Charles R. Olmstead	1/31/2015	50,000	$	271,000	(1)
	1/31/2015	50,000	$	253,000	(2)
Jeffrey R. Olmstead	1/31/2015	50,000	$	271,000	(1)
	1/31/2015	50,000	$	253,000	(2)
Michael D. Peterson	1/31/2015	12,000	$	60,720	(2)
	7/31/2015	6,000	$	16,860	(3)
Nathan P. Pekar	1/31/2015	12,000	$	60,720	(2)
Sherry L. Morgan	1/31/2015	3,000	$	15,180	(2)
Michael L. Wiggins	1/31/2015	15,000	$	81,300	(1)
	1/31/2015	15,000	$	75,900	(2)
	7/31/2015	15,000	$	49,050	(1)

(1) Unrestricted award.
(2) Discretionary award, one-third vested immediately with the remaining two-thirds vesting over a two year period.
(3) Equity-settled phantom award, one-third vested immediately with the remaining two-thirds vesting over a two year period.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2015:

Name	Number of Units That Have Not Yet Vested			Market Value of Units That Have Not Yet Vested [(1)]
Charles R. Olmstead	33,333	(2)	$	38,000
Jeffrey R. Olmstead	33,333	(2)	$	38,000
Michael D. Peterson	6,250	(3)	$	7,125
	8,000	(2)	$	9,120
	4,000	(3)	$	4,560
Nathan P. Pekar	8,000	(2)	$	9,120
Sherry L. Morgan	2,000	(2)	$	2,280

(1) Based on the closing price of our common units at December 31, 2015.
(2) These restricted units vest equally over three years beginning January 31, 2015.
(3) These restricted units vest equally over three years beginning July 31, 2015.

Option Exercises and Stock Vested

The following table sets forth stock awards vested during the year ended December 31, 2015. None of our named executive officers had any stock option exercises during 2015:

Name	Number of Shares Acquired on Vesting	Value Realized on Vesting
Charles R. Olmstead	16,667	$ 90,335
Jeffrey R. Olmstead	16,667	$ 90,335
Michael D. Peterson	3,125	$ 9,750
	4,000	$ 21,680
	2,000	$ 6,240
Nathan P. Pekar	3,332	$ 10,396
	4,000	$ 21,680
Sherry L. Morgan	1,000	$ 5,420
Michael L. Wiggins	5,000	$ 27,100
	10,000	$ 31,200

Potential Post-Employment Payments and Payments upon a Change in Control

Payments Made Upon Any Termination – Regardless of the manner in which a named executive officer's employment terminates, he is entitled to receive amounts earned during his term of employment. Such amounts include:

- accrued but unpaid base salary;
- accrued but unpaid vacation pay;
- any unreimbursed business expenses; and
- any accrued benefits.

Payments Made Upon Termination Without "Cause" or For "Good Reason" – Effective August 2011, we entered into employment agreements with each of S. Craig George, Charles R. Olmstead, and Jeffrey R. Olmstead. In August 2014, S. Craig George elected to terminate his employment agreement. In the event of the termination of any of these named executive officers without "cause" or for "good reason" (each as defined in the employment agreements), if the named executive officer executes and does not revoke a general release of claims, in addition to the items identified above, such named executive officer will be entitled to:

- payment of base salary, as in effect immediately prior to termination, multiplied by the greater of the number of years remaining in the employment period and one;
- a lump sum payment to compensate the named executive officer for COBRA health-care coverage for the named executive officer and the named executive officer's dependents (if applicable);
- accelerated vesting and conversion of any units which may have been awarded to the named executive officer through our long-term incentive program;
- payment of an amount equal to the lesser of the "target annual bonus" (as defined in the employment agreements) and the average of the previous two annual bonuses paid to the named executive officer multiplied by the greater of the number of years remaining in the employment period and one; and
- payment of any unpaid annual bonus that would have become payable to the named executive officer in respect of any calendar year that ends on or before the date of termination had the named executive officer remained employed throughout the payment date of such annual bonus.

Payments Made Upon Death or Disability – In the event of the death or disability of one of these named executive officers, if the officer or his estate executes and does not revoke a general release of claims, in addition to the benefits listed under the heading "Payments Made Upon Any Termination" above, the officer or his estate will be entitled to:

- accelerated vesting and conversion of any units which may have been awarded to the officer through our long-term incentive program, in accordance with the terms of the applicable award agreement;
- a lump sum payment to compensate the officer or the officer's estate for COBRA health-care coverage for the officer (if living) and the officer's dependents (if applicable);
- a payment equal to the product of the officer's base salary as in effect immediately prior to the date of termination multiplied by one;
- payment of any unpaid annual bonus that would have become payable to the officer in respect of any calendar year that ends on or before the date of termination had the officer remained employed through the payment date of such annual bonus; and
- payment of the target annual bonus for the year in which the officer's separation from service occurs.

Payments Made Upon a Change in Control – Each employment agreement has an initial three year term and is automatically extended in one-year increments after the expiration of the initial term unless we provide written notice of non-renewal to the officer, or the officer provides written notice of non-renewal to us, by at least February 1 preceding the August 1 renewal date. If, during the period beginning sixty days prior to and ending two years immediately following a "change in control," either we terminate the officer's employment without "cause," the officer's death occurs, the officer becomes disabled or the officer terminates his employment for "good reason," then in addition to the benefits listed under the heading "Payments Made Upon Any Termination," the officer will be entitled to:

- payment of base salary, as in effect immediately prior to termination, multiplied by two;
- a lump sum payment to compensate the officer for COBRA health-care coverage for the named executive officer and the officer's dependents (if applicable);
- accelerated vesting and conversion of any units which may have been awarded to the officer through our long-term incentive program;
- payment of an amount equal to the lesser of the "target annual bonus" (as defined in the employment agreements) and the average of the previous two annual bonuses paid to the officer multiplied by two; and
- payment of any unpaid annual bonus that would have become payable to the officer in respect of any calendar year that ends on or before the date of termination had the officer remained employed throughout the payment date of such annual bonus.

Additionally, if a change in control occurs during the employment period, certain equity-based awards held by the officers, to the extent not previously vested and converted into common units, will vest in full upon such change in control and will be settled in common units in accordance with the applicable award agreements. Relative to our overall value, we believe the potential benefits payable upon a change in control under these agreements are comparatively minor.

For the purposes of these agreements, a "change in control" generally means any of the following events:

- any "person" or "group" within the meaning of those terms as used in Sections 13(d) and 14(d) of the Exchange Act, other than certain of our affiliated entities, shall become the beneficial owner, directly or indirectly, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in us;
- a plan of complete liquidation, in one or a series of transactions, is approved;
- the sale or other disposition by us of all or substantially all of our assets in one or more transactions to any person other than certain of our affiliated entities;
- a transaction resulting in a person other than us or one of certain of our affiliated entities being our general partner; or
- any time at which individuals who, as of October 31, 2011, constitute our Board of Directors (the "Incumbent Board") cease for any reason to constitute at least a majority of our Board; provided, however, that any individual becoming a director subsequent to October 31, 2011, whose election, or nomination for election by our unitholders was approved by a vote of at least a majority of the directors then comprising the Incumbent Board or whose

membership was required by any employment agreement with us will be considered as though such individuals were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as the result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a person other than the Incumbent Board.

For the purposes of these agreements, "cause" means the willful and continued failure of the officer to perform substantially the officer's duties for us (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the officer by the CEO which specifically identifies the manner in which the CEO believes that the officer has not substantially performed the officer's duties and the officer is given a reasonable opportunity of not more than twenty business days to cure any such failure to substantially perform; the willful engaging by the officer in illegal conduct or gross misconduct, including without limitation a material breach of the our Code of Business Conduct or a material breach of the officer's covenants to follow all laws and all of our policies that relate to nondiscrimination and the absence of harassment and to comply with all requirements under the Sarbanes-Oxley Act, in each case which is materially and demonstrably injurious to us; or any act of fraud, or material embezzlement or material theft by the officer, in each case, in connection with the officer's duties hereunder or in the course of the officer's employment hereunder or the officer's admission in any court, or conviction, or plea of nolo contendere, of a felony involving moral turpitude, fraud, or material embezzlement, material theft or material misrepresentation, in each case, against or affecting us. The CEO's determination of materiality of any embezzlement, theft, or misrepresentation, shall be binding and conclusive on the officer.

For the purposes of these agreements, "good reason" means the occurrence of any of the following without the officers written consent: (i) a material diminution in the officer's base salary; a material diminution in the officer's authority, duties, or responsibilities; a material diminution in the budget over which the officer retains authority; a material change (more than 25 miles) in the geographic location at which the officer's primary location of his under his employment agreement; or any other action or inaction that constitutes a material breach by us of the employment agreement.

Potential Post-Employment Payment Tables – The following tables reflect estimates of our allocated portion of the amount of incremental compensation due to each named executive officer subject to an employment agreement in the event of such executive's termination of employment upon death, disability or retirement, termination of employment without cause or termination of employment without cause or with good reason within three years following a change in control. The amounts shown assume that such termination was effective as of December 31, 2015, and are estimates of the allocated amounts which would be paid out to the executives upon such termination. The actual amounts to be paid out can only be determined at the time of such executive's separation of service.

Charles R. Olmstead	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following Change in Control**
Cash Severance	$ 144,000	$ 144,000	$ 288,000
Restricted Stock/Units	38,000	38,000	38,000
Performance Shares/Units	114,000	114,000	114,000
Health & Welfare	29,670	29,670	29,670
Total	$ 325,670	$ 325,670	$ 469,670

Jeffrey R. Olmstead	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following Change in Control**
Cash Severance	$ 252,000	$ 252,000	$ 504,000
Restricted Stock/Units	38,000	38,000	38,000
Performance Shares/Units	114,000	114,000	114,000
Health & Welfare	43,893	43,893	43,893
Total	$ 447,893	$ 447,893	$ 699,893

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business, requires some degree of risk taking. Accordingly, the use of compensation as an incentive for performance can foster the potential for management and others to take unnecessary or excessive risks to reach performance thresholds which qualify them for additional compensation. From a risk management perspective, our policy is to conduct our commercial activities in a manner intended to control and minimize the potential for unwarranted risk taking. We also routinely monitor and measure the execution and performance of our projects and acquisitions relative to expectations. Additionally, our compensation arrangements include delaying the rewards and subjecting such rewards to forfeiture for terminations related to violations of our risk management policies and practices or of our code of conduct.

Compensation Committee Interlocks and Insider Participation

The NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee, and we do not have a compensation committee. Although the Board of Directors of our general partner does not currently establish a compensation committee, it may do so in the future.

Compensation of Directors

We use a combination of cash and unit-based compensation to attract and retain qualified candidates to serve on our board. In setting director compensation, we consider the significant amount of time that directors expend in fulfilling their duties to us as well as the skill level we require of members of the board.

In 2015, directors who were not officers or employees of us or our affiliates received an annual retainer of $40,000, with the chairman of the audit committee and chairman of the conflict committee receiving an additional annual fee of $5,000. In addition, each non-employee director receives $1,000 per committee meeting attended in person or by phone and is reimbursed for his out of pocket expenses in connection with attending meetings. We indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

Each of the independent directors were awarded 15,900 unrestricted common units in January 2015 and 6,410 unrestricted common units in July 2015.

The following table discloses the cash unit awards and other compensation earned, paid or awarded to each of our directors during the year ended December 31, 2015:

Name (1)	Fee Earned or Paid in Cash	Unit Awards (2)	Total
Peter Adamson III	$ 27,000	$ 107,139	$ 134,139
Cameron O. Smith	$ 25,000	$ 107,139	$ 132,139
Robert W. Berry	$ 22,000	$ 107,139	$ 129,139
C. Fred Ball Jr.	$ 22,000	$ 107,139	$ 129,139
Peter A. Leidel	$ 16,000	$ 107,139	$ 123,139
S. Craig George	$ 40,000	$ 40,650	$ 80,650

(1) Messrs. Olmstead and Olmstead and not included in this table as they are employees of Mid-Con Energy Operating and receive no compensation for their services as directors.
(2) Reflects the fair value of the units granted in January and July 2015.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

As of February 29, 2016, the following table sets forth the beneficial ownership of our common units that are owned by:

- beneficial owners of more than 5% of our common units;
- each executive officer of our general partner; and
- all directors, director nominees and executive officers of our general partner as a group.

Name of Beneficial Owner	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned
Yorktown Energy Partners VI, L.P. (1)(2)	140,436	0.5%
Yorktown Energy Partners VII, L.P. (1)(3)	37,207	0.1%
Kayne Anderson Capital Advisors, L.P./Richard A. Kayne (5)(6)	3,001,873	10.1%
Mid-Con Energy III, LLC (7)	3,714,659	12.5%
Charles R. Olmstead (4)	707,512	2.4%
Jeffrey R. Olmstead (4)	425,763	1.4%
S. Craig George (4)	346,585	1.2%
Nathan P. Pekar (4)	31,350	0.1%
Michael D. Peterson (4)	26,250	0.1%
Sherry L. Morgan (4)	15,719	0.1%
Peter Adamson III (4)	78,685	0.3%
Robert W. Berry (4)	189,733	0.6%
Peter A. Leidel (4)	271,305	0.9%
Cameron O. Smith (4)	38,340	0.1%
C. Fred Ball Jr. (4)	47,310	0.2%
All named executive officers, directors and director nominees as a group (11 people)	2,178,552	7.3%

(1) Has a principal business address of 410 Park Avenue, 19th Floor, New York, New York 10022.

(2) Yorktown VI Company LP is the sole general partner of Yorktown Energy Partners VI, L.P. Yorktown VI Associates LLC is the sole general partner of Yorktown VI Company LP. As a result, Yorktown VI Associates LLC may be deemed to have the power to vote or direct the vote or to dispose or direct the disposition of the common units owned by Yorktown Energy Partners VI, L.P. Yorktown VI Company LP and Yorktown VI Associates LLC disclaim beneficial ownership of the common units owned by Yorktown Energy Partners VI, L.P. in excess of their pecuniary interests therein.

(3) Yorktown VII Company LP is the sole general partner of Yorktown Energy Partners VII, L.P. Yorktown VII Associates LLC is the sole general partner of Yorktown VII Company LP. As a result, Yorktown VII Associates LLC may be deemed to have the power to vote or direct the vote or to dispose or direct the disposition of the common units owned by Yorktown Energy Partners VII, L.P. Yorktown VII Company LP and Yorktown VII Associates LLC disclaim beneficial ownership of the common units owned by Yorktown Energy Partners VII, L.P. in excess of their pecuniary interests therein.

(4) c/o Mid-Con Energy GP, LLC, 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201.

(5) Has a principal business address of 1800 Avenue of the Stars, 3 rd Floor, Los Angeles, CA 90067.

(6) This information has been derived from a Schedule 13G filed with the SEC on January 12, 2016. Based on the information contained in the filing, Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne have shared voting power and dispositive power with respect to, and beneficially own, an aggregate of 3,001,873 common units.

(7) Has a principal business address of 2431 E. 61st Street, Suite 850, Tulsa, OK 74136.

The following table sets forth the beneficial ownership of equity interests in our general partner:

Name of Beneficial Owner	Member Interest (2)
Charles R. Olmstead (1)	33.33%
S. Craig George (1)	33.33%
Jeffrey R. Olmstead (1)	33.33%

(1) c/o Mid-Con Energy GP, LLC, 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201

(2) Messrs. Olmstead, George, and Olmstead, by virtue of their ownership interest in our general partner, may be deemed to beneficially own the interests in us held by our general partner. Each of Messrs. Olmstead, George and Olmstead disclaims beneficial ownership of these securities in excess of his pecuniary interest in such securities.

Securities Authorized for Issuance under Equity Compensation Plan

See the table in "Item 11. Executive Compensation - Long-Term Incentive Program."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

As of December 31, 2015, our general partner has an approximate 1.2% interest in us. The distributions we will make to our general partner are described under Item 5.

Agreements with Affiliates in Connection with the Transactions

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

Reimbursement of Expenses

We entered into 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 to us, which include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. Mid-Con Energy Operating has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us. Mid-Con Energy Operating will not be liable to us for its performance of, or failure to perform, services under the services agreement unless its acts or omissions constitute gross negligence or willful misconduct. For the year ended December 31, 2015, we reimbursed Mid-Con Energy Operating approximately $3.7 million for direct operating expenses.

Transactions and Other Agreements

During 2015, we did not have any transactions with our Mid-Con Affiliate. In the past, we have acquired properties from our Mid-Con Affiliate and the terms of such acquisitions were approved by the Conflicts Committee of the Board of Directors of the General Partner (the "Conflicts Committee"). The Conflicts Committee, which is composed entirely of independent directors, retained independent legal and financial counsel to assist it in evaluating and negotiating the purchase agreements and acquisitions. Any future transactions with our Mid-Con Affiliate would be handled in the same manner.

Other Transactions with Related Persons

Operating Agreements

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are party to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies or COPAS overhead fee). We and those third parties pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements. For the years ended December 31, 2015 and 2014, we paid Mid-Con Energy Operating $8.3 million and $6.1 million, respectively, for COPAS overhead fees, pumper and supervision fees pursuant to the operating agreements. For the years ended December 31, 2015 and 2014, Mid-Con Energy Operating billed us $3.7 million, each year, for oilfield services performed by our affiliate ME3 Oilfield Service. These services were billed according to operating agreements.

Review, Approval or Ratification of Transactions with Related Persons

We have adopted a Code of Business Conduct that sets forth our policies for the review, approval and ratification of transactions with related persons. Pursuant to our Code of Business Conduct, a director is expected to bring to the attention of the Chief Executive Officer or the Board of Directors of our general partner any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict will be addressed in accordance with our general partner's organizational documents and the provisions of our partnership agreement. The resolution may be determined by disinterested directors, our general partners' Board of Directors, or the conflicts committee of our general partner's Board of Directors. Our Code of Business Conduct is on our website www.midconenergypartners.com under our corporate governance section.

The Mid-Con Affiliates or other affiliates of our general partner are free to offer properties to us on terms they deem acceptable, and the Board of Directors of our general partner (or the conflicts committee) is free to accept or reject any such offers, negotiating terms it deems acceptable to us. As a result, the Board of Directors of our general partner (or the conflicts committee) will decide, in its sole discretion, the appropriate value of any assets offered to us by affiliates of our general partner. In so doing, we expect the Board of Directors (or the conflicts committee) will consider a number of factors in its determination of value, including, without limitation, production and reserve data, operating cost structure, current and projected cash flow, financing costs, the anticipated impact on distributions to our unitholders, production decline profile, commodity price outlook, reserve life, future drilling inventory and the weighting of the expected production between oil and natural gas.

We expect that the Mid-Con Affiliates or other affiliates of our general partner will consider a number of the same factors considered by the Board of Directors of our general partner to determine the proposed purchase price of any assets it may offer to us in future periods. In addition to these factors, given that the Founders and Yorktown are our largest unitholders, they may consider the potential positive impact on their underlying investment in us by causing the Mid-Con Affiliates to offer properties to us at attractive purchase prices. Likewise, the affiliates of our general partner may consider the potential negative impact on their underlying investment in us if we are unable to acquire additional assets on favorable terms, including the negotiated purchase price.

Director Independence

NASDAQ does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the Board of Directors of our general partner. For a discussion of the independence of the Board of Directors of our general partner, please see “Item 10. Directors, Executive Officers and Corporate Governance.”

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The audit committee of Mid-Con Energy GP, LLC selected Grant Thornton LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the year ended December 31, 2015 and 2014. The audit committee’s charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit-related, tax and all other fees categories below with respect to this Annual Report on Form 10–K for the year ended December 31, 2015 were approved by the audit committee.

Fees paid to Grant Thornton LLP are as follows:

	2015	2014
Audit fees	$ 411,875	$ 406,070
Audit-related	—	117,383
Tax fees	117,501	125,424
Total	$ 529,376	$ 648,877

PART IV

ITEM 15. EXHIBITS

(a)(1) *Exhibits*

The exhibits listed below are filed or furnished as part of this report:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 3.1 to Mid-Con Energy Partners, LP’s registration statement on Form S-1 filed with the SEC on August 12, 2011 (File No.333-176265)).
3.2	Certificate of Formation of Mid-Con Energy GP, LLC (incorporated by reference to Exhibit 3.4 to Mid-Con Energy Partners, LP’s registration statement on Form S-1 filed with the SEC on August 12, 2011 (File No. 333-176265)).
3.3	First Amended and Restated Agreement of Limited Partnership of Mid-Con Energy Partners, LP, dated as of December 20, 2011 (incorporated by reference to Exhibit 3.1 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).

3.4	Amended and Restated Limited Liability Company Agreement of Mid-Con Energy GP, LLC, dated as of December 20, 2011 (incorporated by reference to Exhibit 3.2 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).
10.1	Services Agreement, dated as of December 20, 2011, by and among Mid-Con Energy Operating, Inc., Mid-Con Energy GP, LLC, Mid-Con Energy Partners, LP and Mid-Con Energy Properties, LLC (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).
10.2	Credit Agreement, dated as of December 20, 2011, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.2 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).
10.3	Agreement and Amendment No. 1 to Credit Agreement, dated as of April 23, 2012, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on April 27, 2012).
10.4	Agreement and Amendment No. 2 to Credit Agreement, dated as of November 26, 2012, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on November 28, 2012).
10.5	Agreement and Amendment No.3 to Credit Agreement, dated as of November 5, 2013, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on November 6, 2013).
10.6	Amendment No.4 to Credit Agreement, dated as of April 11, 2014, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.01 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on April 15, 2014).
10.7	Agreement and Amendment No.5 to Credit Agreement, dated as of April 11, 2014, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.01 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on April 15, 2014).
10.8	Amendment No.6 to Credit Agreement, dated as of February 12, 2015, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.01 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on February 17, 2015).
10.9	Amendment No.7 to Credit Agreement, dated as of November 30, 2015, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 1, 2015).
10.10	Contribution, Conveyance, Assumption and Merger Agreement, by and among Mid-Con Energy GP, LLC, Mid-Con Energy Partners, LP, Mid-Con Energy Properties, LLC, Mid-Con Energy I, LLC, Mid-Con Energy II, LLC and Charles R. Olmstead, S. Craig George, Jeffrey R. Olmstead and other members of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC named therein (incorporated by reference to Exhibit 10.3 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).
10.11	Mid-Con Energy Partners, LP Long-Term Incentive Program (incorporated by reference to Exhibit 4.5 to Mid-Con Energy Partners, LP’s Registration Statement on Form S-8 filed with the SEC on January 25, 2012 (File No 333-179161)).
10.12	Amendment No. 1 to Mid-Con Energy Partners, LP Long-Term Incentive Program (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the Commission on November 20, 2015).
10.13	Form of Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).

10.14	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and Charles R. Olmstead (incorporated by reference to Exhibit 10.6 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).
10.15	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and Jeffrey R. Olmstead (incorporated by reference to Exhibit 10.7 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).
10.16	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and S. Craig George (incorporated by reference to Exhibit 10.8 to Mid-Con Energy Partners, LP’s current report on Form 8-K filed with the SEC on December 23, 2011).
10.17	Purchase and Sale Agreement dated February 28, 2014 by and among Mid-Con Energy III, LLC, Mid-Con Energy Properties, LLC and Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy, LP’s current report on Form 8-K filed with the SEC on March 5, 2014).
10.18	Form of Crude Oil Purchase Agreement between Mid-Con Energy Operating, LLC and Enterprise Crude Oil LLC (incorporated by reference to Exhibit 10.10 to Mid-Con Energy LP's current report on Form 10-K filed with the SEC on March 9, 2012).
10.19	Purchase and Sale Agreement, dated February 28, 2014, by and among Mid-Con Energy III, LLC, Mid-Con Energy Properties, LLC and Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on March 5, 2014).
10.20	Purchase and Sale Agreement, dated July 24, 2014, by and among Mid-Con Energy III, LLC, Mid-Con Energy Properties, LLC and Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on July 25, 2014).
10.21	Purchase and Sale Agreement, dated October 7, 2014, by and among Mid-Con Energy Properties, LLC, Mid-Con Energy Partners, LP and L.C.S. Production Company, SPA-PETCO, LP, SPA PETCO OSU, LLC, A.G. Hill Oil and Gas LP, and A.G. Hill Oil and Gas II LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on October 14, 2014).
10.22	Form of Phantom Unit Award Agreement (for employees of our Affiliate)(incorporated by reference to Exhibit 10.14 to Mid-Con Energy LP's current report on Form 10-K/A filed with the SEC on June 24, 2014).
21.1	Subsidiaries of Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 21.1 to Mid-Con Energy LP's current report on Form 10-K filed with the SEC on March 9, 2012).
22.1	Amendment No.1 to Employment Agreement, dated as of January 29, 2014, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and S. Craig George (incorporated by reference to Exhibit 22.1 to Mid-Con Energy LP's current report on Form 10-K filed with the SEC on March 5, 2014).
23.1+	Consent of Cawley, Gillespie & Associates, Inc.
23.2+	Consent of Grant Thornton LLP
31.1+	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
31.2+	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
32.1+	Section 1350 Certification of Chief Executive Officer
32.2+	Section 1350 Certification of Chief Financial Officer
99.1+	Cawley, Gillespie & Associates, Inc. Reserve Report
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

Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

+ Filed herewith

++ Furnished herewith

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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
(Registrant)

		By:	Mid-Con Energy GP, LLC, its general partner
Date:	February 29, 2016	By:	*/s/ Michael D. Peterson*
			Michael D. Peterson Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 29, 2016 .

Signature	Title	Date
/s/ Jeffrey R. Olmstead Jeffrey R. Olmstead	Chief Executive Officer and Director (Principal Financial Officer)	February 29, 2016
/s/ Michael D. Peterson Michael D. Peterson	Chief Financial Officer (Principal Financial Officer)	February 29, 2016
/s/ Sherry L. Morgan Sherry L. Morgan	Chief Accounting Officer	February 29, 2016
/s/ Charles R. Olmstead Charles R. Olmstead	Executive Chairman of the Board	February 29, 2016
/s/ Peter A. Leidel Peter A. Leidel	Director	February 29, 2016
/s/ Cameron O. Smith Cameron O. Smith	Director	February 29, 2016
/s/ Robert W. Berry Robert W. Berry	Director	February 29, 2016
/s/ Peter Adamson III Peter Adamson III	Director	February 29, 2016
/s/ C. Fred Ball Jr. C. Fred Ball Jr.	Director	February 29, 2016
/s/ S. Craig George S. Craig George	Director	February 29, 2016

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DRIVE, SUITE 100
AUSTIN, TEXAS 78729-1707
512-249-7000

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817- 336-2461

1000 LOUISIANA STREET, SUITE 625
HOUSTON, TEXAS 77002-5008
713-651-9944

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CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the references to our firm, references to Cawley, Gillespie & Associates, Inc. as independent petroleum engineers and to the inclusion of information taken from our reserve audit of Mid-Con Energy Partners, LP as of December 31, 2015 in the Mid-Con Energy Partners, LP Annual Report on Form 10-K for the year ended December 31, 2015, (the “10-K”) and all appendixes, exhibits and attachments thereto filed by Mid-Con Energy Partners, LP. We further consent to the inclusion of our reserve audit dated February 4, 2016 as Exhibit 99.1 in the 10-K.

Sincerely,

Cawley, Gillespie & Assoc., Inc.

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

February 24, 2016
Fort Worth, Texas

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 29, 2016, with respect to the consolidated financial statements included in the Annual Report of Mid-Con Energy Partners, LP on Form 10-K for the year ended December 31, 2015. We hereby consent to the incorporation by reference of said report in the Registration Statements of Mid-Con Energy Partners, LP on Forms S-3 (File No. 333-195669 and File No. 333-187012) and on Forms S-8 (File No. 333-179161 and File No. 333-208203).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 29, 2016

Exhibit 31.1

I, Jeffrey R. Olmstead, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mid-Con Energy Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2016

/s/ Jeffrey R. Olmstead

Jeffrey R. Olmstead
Chief Executive Officer

Exhibit 31.2

I, Michael D. Peterson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mid-Con Energy Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 29, 2016

/s/ Michael D. Peterson

Michael D. Peterson
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Mid-Con Energy Partners, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2015 , as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Jeffrey R. Olmstead, Chief Executive Officer of the Partnership, certify, pursuant to18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 29, 2016

/s/ *Jeffrey R. Olmstead*

Jeffrey R. Olmstead
Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Mid-Con Energy Partners, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2015 , as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Michael D. Peterson, Chief Financial Officer of the Partnership, certify, pursuant to18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 29, 2016

/s/ Michael D. Peterson

Michael D. Peterson
Chief Financial Officer

Exhibit 99.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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February 4, 2016

Mr. Jeffrey R. Olmstead
Chief Executive Officer
Mid-Con Energy Partners, LP
2501 N. Harwood, Suite 210
Dallas, Texas 75201

Re: Reserve Audit

Mid-Con Energy Partners, LP Interests
Total Proved Reserves
As of January 1, 2016

Pursuant to the Guidelines of the
Securities and Exchange Commission for
Reporting Corporate Reserves and
Future Net Revenue

Dear Mr. Olmstead,

At your request, this letter was prepared for Mid-Con Energy Partners, LP ("MCEP") on February 4, 2016 for the purpose of describing our audit of your estimates of proved reserves and forecasts of economics attributable to the subject interests. We examined 100% of MCEP reserves, which are made up of oil and gas properties in various fields in Texas, Colorado and Oklahoma. This examination utilized an effective date of January 1, 2016, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the Securities and Exchange Commission (SEC). Our examination included all methods and procedures as we considered necessary under the circumstances to render the opinion set forth herein. The estimates as prepared by MCEP are summarized as follows:

	Net Oil (Mbbls)	Net Gas (MMcf)	Net MBOE	Cumulative Cash Flow Disc. @ 10% (M$)
Total Proved	21,115	6,827	22,252	202,362
Proved Developed Producing	13,429	4,528	14,184	147,841
Proved Developed Behind Pipe	674	214	710	11,571
Proved Developed Non-Producing	265	19	269	2,765
Proved Undeveloped	6,746	2,065	7,090	40,185

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its "present worth". The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base. Our audit involved proved reserves only and did not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated.

Hydrocarbon Pricing

The base SEC oil and gas prices calculated for December 31, 2015 were $50.28/bbl and $2.58 /MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The base oil and gas prices are based upon WTI-Cushing and Henry Hub spot prices, respectively, as published by the EIA for January 1, 2015 through December 1, 2015.

The base prices shown above were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $47.23 per barrel for oil and $2.02 per MCF for gas. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, severance taxes, lease operating expenses and investments were calculated and prepared by MCEP and were reviewed by us for reasonableness. Lease operating expenses were either determined at the field or individual well level using averages calculated from historical lease operating statements. All economic parameters, including lease operating expenses and investments, were held constant (not escalated) throughout the life of these properties.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in pages 6 and 7 following this letter. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. Government policies and market conditions different from those employed in this report may cause (1) the total quantity of oil or gas to be recovered, (2) actual production rates, (3) prices received, or (4) operating and capital costs to vary from those presented in this report. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

This evaluation includes 110 proved undeveloped cases in various fields in Texas and Oklahoma but only 86 of these represent new drilled producing wellbores (drilling locations) with the remainder representing additional reserves associated with recompletions, conversions to injectors and water flooding of existing wellbores. Each of these drilling locations proposed as part of MCEP's development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, MCEP has indicated they have every intent to complete this development plan within the next five years. Furthermore, MCEP has demonstrated that they have the proper company staffing, financial backing and prior development success to ensure this five year development plan will be fully executed.

Reserve Estimation Methods

The methods employed in estimating reserves are described in page 5 following this letter. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for both developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. For certain fields either being waterflooded or prepared for a waterflood, proved undeveloped reserves were based upon results from either a pilot waterflood (in the field) or an analogous, nearby waterflood deemed to be relevant. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for MCEP properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this audit.

General Discussion

An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have *not* been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. ("CG&A"). Possible environmental liability related to the properties has not been investigated or considered. The cost of plugging and the salvage value of equipment at abandonment have not been included.

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

It should be understood that our audit and the development of our reserves forecasts do not constitute a complete reserve study of the oil and gas properties of MCEP. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by MCEP with respect to ownership interests, oil and gas production, historical costs of operation and developments, product prices, agreements relating to current and future operations and sales of production. Furthermore, if in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

Please be advised that, based upon the foregoing, in our opinion the above-described estimates of Mid-Con Energy Partners, LP's total proved reserves are, in the aggregate, reasonable within the established audit tolerance guidelines of (+ or –) 10%. Also, these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers and as mandated by the SEC.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. This evaluation was supervised by Robert D. Ravnaas, President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #61304). We do not own an interest in the properties or Mid-Con Energy Partners, LP and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this audit. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Sincerely,

CAWLEY, GILLESPIE & ASSOCIATES, INC.

STATE OF TEXAS
ROBERT D. RAVNAAS
61304
LICENSED
PROFESSIONAL ENGINEER

Robert D. Ravnaas, P.E.
President

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance* , (2) *material balance* , (3) *volumetric* and (4) *analogy* . Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance . This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance . This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric . This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy . This method which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained by this method are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **Proved oil and gas reserves**. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations— prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"(i) The area of a reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

"(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

"(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

"(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

"(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"(6) **Developed oil and gas reserves**. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

“(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

“(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"(31) **Undeveloped oil and gas reserves**. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

“(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

“(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

“(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

"(18) **<u>Probable reserves</u> .** Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

“(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

“(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

“(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

“(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

"(17) **<u>Possible reserves</u> .** Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

“(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

“(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

“(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

“(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

“(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

“(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.”

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: “The registrant is *permitted, but not required* , to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item.”

"(26) **<u>Reserves</u> .** Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"Note to paragraph (26) : Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)."