Mid-Con Energy Partners, LP
Form 424B1
October 17, 2012
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Filed pursuant to Rule 424(b)(1)
Registration No. 333-184120

PROSPECTUS

Mid-Con Energy Partners, LP

4,000,000 Common Units

Representing Limited Partner Interests

We are a Delaware limited partnership formed in July 2011 to own, operate, acquire, exploit and develop producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States.

We are offering 1,000,000 common units and Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P. are offering an aggregate of 3,000,000 common units in this offering.

Our common units are traded on the NASDAQ Global Market under the symbol MCEP. On October 12, 2012, the last reported sales price of our common units on the NASDAQ Global Market was $22.84 per common unit.

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

Investing in our common units involves risks. See Risk Factors beginning on page 24.

These risks include the following:

- We may not have sufficient cash to pay any quarterly distribution on our units following the establishment of cash reserves and payment of expenses, including payments to our general partner.

- A decline in oil prices, or an increase in the differential between the NYMEX or other benchmark prices of oil and the wellhead price we receive for our production, will cause a decline in our cash flow from operations, which could cause us to reduce our distributions or cease paying distributions altogether.

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

Our general partner, who controls us, has conflicts of interest with, and owes limited fiduciary duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Neither we nor our general partner have any employees, and we rely solely on an affiliate of our general partner to manage and operate our business. The individuals who manage us also provide substantially similar services to affiliates of our general partner, and thus are not solely focused on our business.

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

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors.

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

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

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

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

PRICE $21.20 PER COMMON UNIT

	Per Common Unit	Total
Public offering price	$ 21.20	$ 84,800,000
Underwriting discount	$ 0.848	$ 3,392,000
Proceeds, before expenses, to Mid-Con Energy Partners, LP	$ 20.352	$ 20,352,000
Proceeds, before expenses, to Selling Unitholders	$ 20.352	$ 61,056,000

The Selling Unitholders have granted the underwriters a 30-day option to purchase up to an additional 600,000 common units on the same terms and conditions as set forth above if the underwriters sell more than 4,000,000 common units in this offering.

The underwriters expect to deliver the common units on or about October 22, 2012.

RBC Capital Markets **Raymond James** **UBS Investment Bank** **Wells Fargo Securities**

Baird **Oppenheimer & Co.** **Stephens Inc.**

October 16, 2012

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As of December 31, 2011, we had total estimated proved reserves of 10.0 MMBoe, 99% of which were oil and 69% of which were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating, Inc. operated 99% of our reserves and 96% of such reserves were being operated under waterflood, both on a Boe basis.

As of June 30, 2012, we had 320 gross producing wells (224 net wells), 149 gross injection wells (97 net wells), and 81 gross wells (67 net wells) shut-in or waiting on completion.

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You should rely only on the information contained in this prospectus. We have not, and the underwriters and Selling Unitholders have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters and Selling Unitholders are not, making an offer to sell these securities in any jurisdiction where such an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus only. Our business, financial condition, results of operations and prospects may have changed since that date.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. Please read Risk Factors and Forward-Looking Statements.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Although we believe these third-party sources are reliable and that the information is accurate and complete, we have not independently verified the information.

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including Risk Factors and the historical and unaudited financial statements and the notes to those financial statements. The information presented in this prospectus assumes that the underwriters do not exercise their option to purchase up to an additional 600,000 common units from the Selling Unitholders, unless otherwise indicated. As used in this prospectus, unless we indicate otherwise:

- *Founders collectively refers to Charles R. Olmstead, S. Craig George and Jeffrey R. Olmstead;*
- *initial public offering refers to our December 2011 initial public offering of 5,400,000 of our common units and subsequent over-allotment offering of 810,000 of our common units;*
- *our general partner refers to Mid-Con Energy GP, LLC;*
- *Mid-Con Affiliates collectively refers to Mid-Con Energy III, LLC and Mid-Con Energy IV, LLC, which are affiliates of Yorktown;*
- *Mid-Con Energy Partners, the partnership, we, our, us or like terms when referring to periods prior to our initial public offering generally refer to our predecessor, which was merged with and into Mid-Con Energy Properties, LLC, our wholly owned subsidiary, in connection with our initial public offering. When used in reference to periods after our initial public offering or prospectively, those terms refer to Mid-Con Energy Partners, LP, a Delaware limited partnership, and its subsidiaries;*
- *Mid-Con Energy Operating refers to our affiliate Mid-Con Energy Operating, Inc.*;
- *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;*
- *Selling Unitholders refers to Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P.; 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. and/or Yorktown Energy Partners IX, L.P.*

We include a glossary of some of the oil and natural gas terms used in this prospectus in Appendix A.

Mid-Con Energy Partners, LP

Overview

We are a Delaware limited partnership formed in July 2011 to own, operate, acquire, exploit and develop producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. Our management team has significant industry experience, especially with waterflood projects and, as a result, our operations focus primarily on enhancing the development of

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producing oil properties through waterflooding. Through the continued development of our existing properties and through future acquisitions, we will seek to increase our reserves and production in order to maintain 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 significant portion of our production volumes through various commodity derivative contracts.

As of December 31, 2011, our total estimated proved reserves were 10.0 MMBoe, of which approximately 99% were oil and 69% were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating operated 99% of our properties and 96% of our properties were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended June 30, 2012 was approximately 1,844 Boe per day and based on our December 31, 2011 audited reserves, as adjusted for average net production for the six months ended June 30, 2012, our total estimated proved reserves had a reserve-to-production ratio of approximately 15 years. As of December 31, 2011, our management team developed approximately 59% of our total reserves through new waterflood projects.

Our Properties

Our properties are located in the Mid-Continent region of the United States and primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates. Our core areas of operation are located in Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. As of December 31, 2011, approximately 91% of the properties associated with our estimated reserves, on a Boe basis, have been producing continuously since 1982 or earlier. Through the application of waterflooding, we believe these mature properties have attractive upside potential. Waterflooding, a form of secondary oil recovery, works by repressuring a reservoir through water injection and pushing or sweeping oil to producing wellbores. Based on the production estimates from our December 31, 2011 audited reserve report, the average estimated decline rate for our proved developed producing reserves is approximately 8.0% for 2012 and, on a compounded average decline basis, approximately 11% for the subsequent five years and approximately 10% thereafter.

The following table summarizes information by core area regarding our estimated oil and natural gas reserves as of December 31, 2011 and our average net production for the month ended June 30, 2012.

	Estimated Net Proved Reserves as of December 31, 2011				Average Net Production for the Month Ended June 30, 2012			Gross Active Wells as of June 30, 2012		
	(MBoe)	% Operated	% Oil	% Proved Developed	Boe/d Gross	Boe/d Net	Reserve-to-Production Ratio(1)	Oil and Natural Gas Wells	Injection Wells	Shut-in/ Waiting on Completion
Southern Oklahoma	5,528	100%	100%	68%	2,600	1,128	13	79	53	12
Northeastern Oklahoma	3,179	100%	99%	69%	742	447	19	201	76	54
Hugoton Basin	1,060	100%	99%	69%	340	219	13	29	15	13
Other	282	77%	77%	100%	140	50	15	11	5	2
Total	**10,049**	**99%**	**99%**	**69%**	**3,822**	**1,844**	**15**	**320**	**149**	**81**

(1) The reserve-to-production ratio is calculated by subtracting net production for the six months ended June 30, 2012 from estimated net proved reserves as of December 31, 2011 and dividing the result by average net production for the month ended June 30, 2012.

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The following chart summarizes our total average net Boe production volumes on a monthly basis, and illustrates the 47% increase in our production volumes over the twelve months ended June 30, 2012. We achieved this production increase primarily through ongoing waterflood response from existing development activities and from workovers and acquisitions.

Recent Developments

On October 15, 2012, we entered into a Purchase and Sale Agreement to acquire certain oil properties located in our Hugoton Basin core area. The base purchase price for such properties, which is subject to standard adjustments and preference right exercises, is approximately $21 million, which includes a performance deposit of $2.1 million. This acquisition is expected to close on or before November 6, 2012 and will be financed using existing cash and borrowings from our credit facility. This acquisition includes current net production of approximately 175 Boe per day, estimated net proved reserves of approximately 1.3 MMBoe (55% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. We will acquire 14 gross producing, 7 gross injecting and 1 gross water supply well associated with these properties. The estimated proved reserves for this acquisition were based on our preliminary internal evaluation of information provided by the seller and proved reserves as of the acquisition date for the above-referenced acquisition were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that this acquisition will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property

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may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Additionally, on October 12, 2012, we entered into an agreement to assign additional working interests in our existing War Party I and II Units located in our Hugoton Basin core area, effective as of April, 2012. Pursuant to the agreement, we will pay approximately $3.5 million for these properties using existing cash and borrowings from our credit facility. As a result of this assignment, we will have 100% and 99% of the working interests in our War Party I and II Units, respectively. The working interests to be assigned include current net production of approximately 83 Boe per day, estimated net proved reserves of approximately 0.5 MMBoe (85% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. The estimated proved reserves for the working interests to be assigned are based on our preliminary internal evaluation of information provided by the seller, and proved reserves as of the effective date for the above-referenced assignment is estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that the working interests included in this assignment will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Completion of these acquisitions are subject to the satisfaction of customary closing conditions and the waiver of preference rights and obtaining necessary consents from third parties. Failure to satisfy these conditions, if not waived, would prevent us from consummating these acquisitions or the amount of properties we may obtain may be materially reduced, resulting in a proportional decrease in our expected net reserves and production. As a result, we can provide no assurance that these acquisitions will be completed within the anticipated time frame, or at all. The closing of these acquisitions is not conditioned on the closing of this offering, and this offering is not conditioned on the closing of these acquisitions. In the event that we are unable to complete these acquisitions, our approximately $2.1 million deposit we have paid for the Clawson Ranch would potentially be subject to forfeiture.

During June 2012, we acquired certain oil properties located in our Northeastern Oklahoma core area, and additional working interests in our existing units in our Southern Oklahoma core area, in unrelated transactions. We paid approximately $16.4 million in aggregate consideration for these properties. The transactions were financed using existing cash and borrowings from our credit facility. These acquisitions include current net production of approximately 115 Boe per day, estimated net proved reserves of approximately 0.6 MMBoe (53% proved developed producing and 100% oil on a Boe basis) and an average reserve-to-production ratio of approximately 14 years. The estimated proved reserves for these acquisitions were based on our preliminary internal evaluation of information provided by the sellers and proved reserves as of the acquisition date for the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that these acquisitions were immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for these properties may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

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Our general partner also declared a cash distribution of $0.485 per unit ($1.94 per unit on an annualized basis) on October 15, 2012 for the third quarter of 2012, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 7, 2012. This is an increase of $0.01 from the previous quarter. Our management also confirmed on October 15, 2012 that our previously released Boe production guidance for the third quarter of 2012 will come in within the previously announced range, likely toward the lower-end.

Our Hedging Strategy

Our hedging strategy is to enter into various commodity derivative contracts intended to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program s objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distribution over time, while retaining some ability to participate in upward movements in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher hedged percentage in the near 12 months of the period. For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our audited proved reserves as of December 31, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, respectively. A collar is a combination of a put option we purchase and a call option we sell. The put option portion of a collar is also referred to as a floor. A floor establishes a minimum average sale price for future oil 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 as opposed to entering 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 percentage of our hedged production volumes or the duration of our hedge contracts when circumstances suggest that it is prudent to do so.

By removing a significant 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 flow from operations for those periods. For a further description of our commodity derivative contracts, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Derivative Contracts.

Our Business Strategies

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which we expect will provide stability and, over time, growth of distributions to our unitholders. In addition to our hedging strategy described above, we intend to execute the following business strategies:

- Continue exploitation of our existing properties to maximize production;
- Pursue acquisitions of long-lived, low-risk producing properties with upside potential;
- Capitalize on our relationship with the Mid-Con Affiliates for favorable acquisition opportunities;

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- Maintain operational control and a focus on cost-effectiveness in all our operations;
- Reduce the impact of commodity price volatility on our cash flow through a disciplined commodity hedging strategy;
- Maintain a balanced capital structure to allow for financial flexibility to execute our business strategies; and
- Utilize compensation programs that align the interests of our management team with our unitholders.

For a more detailed description of our business strategies, please read Business and Properties Our Business Strategies.

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 99% are oil, and relatively predictable production profiles that provide growth potential through ongoing response to waterflooding and that have modest capital requirements;
- The ability to further exploit existing mature properties by utilizing our waterflooding expertise;
- 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 Affiliates;
- Access to the collective expertise of Yorktown s employees and their extensive network of industry relationships through our relationship with Yorktown;
- Mid-Con Energy Operating operates 99% of our properties, which allows them to control our operating costs and capital expenditures;
- An enhanced ability to pursue acquisition opportunities arising from our competitive cost of capital and balanced capital structure; and
- The range and depth of our technical and operational expertise will allow us to expand both geographically and operationally to achieve our goals.

For a more detailed discussion of our competitive strengths, please read Business and Properties Our Competitive Strengths.

Our Principal Business Relationships

Our Relationship with the Mid-Con Affiliates

In June 2011, management and Yorktown formed two limited liability companies, which we refer to collectively as the Mid-Con Affiliates, to acquire and develop 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 certain of these properties from the Mid-Con Affiliates. Through this relationship with the Mid-Con Affiliates, 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, the Mid-Con Affiliates may not be successful in identifying or consummating acquisitions or in successfully developing the new properties

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they acquire. Further, the Mid-Con Affiliates are not obligated to sell any properties to us and they are not prohibited from competing with us to acquire oil and natural gas properties. Please read Certain Relationships and Related Party Transactions Review, Approval or Ratification of Transactions with Related Persons.

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. Yorktown made several equity investments in our predecessor. Prior to this offering, Yorktown owned an approximate 48.5% limited partner interest in us, making it our largest unitholder. Immediately following this offering, Yorktown will own an approximate 30.1% limited partner interest in us (or an approximate 26.9% limited partner interest in us if the underwriters exercise their option to purchase additional common units in full), and will continue to be our largest unitholder. Yorktown Energy Partners IX, L.P. will continue to own a 50% interest in our affiliate, Mid-Con Energy Operating. Also, Peter A. Leidel, a principal of Yorktown, serves on our board of directors.

Yorktown currently has more than $3.0 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, we believe that 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 the Mid-Con Affiliates, that are engaged in the oil and natural gas industry and, as a result, Yorktown may present acquisition opportunities to other Yorktown portfolio companies, including the Mid-Con Affiliates, that compete with us.

Risk Factors

An investment in our common units involves risks. Below is a summary of certain key risk factors that you should consider in evaluating an investment in our common units. This list is not exhaustive. Please read the full discussion of these risks and other risks described under Risk Factors.

Risks Related to Our Business

- We may not have sufficient cash to pay any quarterly distribution on our units following the establishment of cash reserves and payment of expenses, including payments to our general partner.

- A decline in oil prices, or an increase in the differential between the NYMEX or other benchmark prices of oil and the wellhead price we receive for our production, will cause a decline in our cash flow from operations, which could cause us to reduce our distributions or cease paying distributions altogether.

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

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

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Our business depends in part on transportation, pipelines and refining facilities owned by others. Any limitation in the availability of those facilities, or increase in their costs, could interfere with our ability to market our production and adversely affect our revenues.

Risks Inherent in an Investment in Us

Our general partner controls us, and following this offering, the Founders and Yorktown will own a 36.0% limited partner interest in us, or a 32.8% limited partner interest in us if the underwriters exercise their option to purchase additional common units in full. 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.

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 Affiliates, and thus is not solely focused on our business.

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

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors.

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

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

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.

Tax Risks to Unitholders

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

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.

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Ownership and Organizational Structure of Mid-Con Energy Partners, LP

The diagram below depicts our organization and ownership after giving effect to the offering and assumes that the underwriters do not exercise their option to purchase additional common units from the Selling Unitholders.

Common units held by the public	53.4%
Common units held by the Founders	5.8%
Common units held by Yorktown	29.5%
Common units held by our executive officers, employees and other individuals and entities, other than the Founders and Yorktown who held membership interests in our predecessor	9.4%
General partner units	1.9%
Total	100.0%

(1) The Founders are S. Craig George, Charles R. Olmstead and Jeffrey R. Olmstead.

(2) Yorktown Energy Partners IX, L.P. owns a 50% interest in Mid-Con Energy Operating. Yorktown IX Company LP is the sole general partner of Yorktown Energy Partners IX, L.P. Yorktown Associates LLC is the sole general partner of Yorktown IX Company LP. Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P. own common units in us. For more information on the entities that control Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P., please read Security Ownership of Certain Beneficial Owners and Management.

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Management of Mid-Con Energy Partners, LP

We are managed and operated by the board of directors and executive officers of our general partner, Mid-Con Energy GP, LLC. Our unitholders are not entitled to elect our general partner or its directors or otherwise participate in our management or operation. All of the executive officers of our general partner are also officers and/or directors of the Mid-Con Affiliates. For information about the executive officers and directors of our general partner, please read Management.

S. Craig George, the Executive Chairman of the board of directors of our general partner, Charles R. Olmstead, the Chief Executive Officer and a director of our general partner, and Jeffrey R. Olmstead, the President and Chief Financial Officer and a director of our general partner, each own one-third of the member interests in our general partner. As the holders of all of the member interests of our general partner, the Founders control our general partner, are entitled to appoint its entire board of directors and receive all of the distributions our general partner receives in respect of its approximate 2.0% general partner interest in us. Please read Security Ownership of Certain Beneficial Owners and Management.

Neither we, our general partner, nor our subsidiary have any employees. We and our general partner are parties to a services agreement with Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating provides management, administrative and operational services to us. Although all of the employees that conduct our business are employed by Mid-Con Energy Operating, we sometimes refer to these individuals in this prospectus as our employees.

We have one subsidiary, Mid-Con Energy Properties, that holds title to our properties.

Principal Executive Offices and Internet Address

Our headquarters are located at 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201. Our principal operating office is located at 2431 East 61st Street, Suite 850, Tulsa, Oklahoma 74136, and our telephone number is (972) 479-5980. Our website address is www.midconenergypartners.com. We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as the SEC, available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

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Summary of Conflicts of Interest and Fiduciary Duties

Under our partnership agreement, our general partner has a legal duty to manage us in a manner that is in, or not opposed to, the best interests of the holders of our common units. This legal duty, as modified by our partnership agreement, originates in statutes and judicial decisions and is commonly referred to as a fiduciary duty. However, the officers and directors of our general partner also have a fiduciary duty to manage the business of our general partner in a manner beneficial to its owners, the Founders. All of the executive officers of our general partner are also officers and/or directors of the Mid-Con Affiliates and have economic interests in the Mid-Con Affiliates. In addition, Peter A. Leidel, a principal of Yorktown, serves on our board of directors. Mr. Leidel has economic interests in Yorktown and its affiliates that manage, hold and own investments in other funds and companies that may compete with us. As a result of these relationships, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its owners and affiliates, on the other hand. For example, our general partner is entitled to make determinations that affect our ability to generate the cash flow necessary to make cash distributions to our unitholders, including determinations related to:

- purchases and sales of oil and natural gas properties and other acquisitions and dispositions, including whether to pursue acquisitions that may also be suitable for the Mid-Con Affiliates, Yorktown or any Yorktown portfolio company;
- the manner in which our business is operated;
- the level of our borrowings;
- the amount, nature and timing of our capital expenditures; and
- the amount of cash reserves necessary or appropriate to satisfy our general, administrative and other expenses and debt service requirements and to otherwise provide for the proper conduct of our business.

For a more detailed description of the conflicts of interest and fiduciary duties of our general partner, please read Risk Factors Risks Inherent in an Investment in Us and Conflicts of Interest and Fiduciary Duties.

Generally, our partnership agreement can be amended in a manner that materially adversely affects our limited partners only with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including any common units held by affiliates of our general partner). Following this offering, our general partner will continue to be owned by the Founders, and the Founders and Yorktown collectively will own and control the voting of an aggregate of approximately 36.0% of our outstanding common units, or approximately 32.8% of our outstanding common units if the underwriters exercise their option to purchase additional common units in full. Please read Risk Factors Risks Inherent in an Investment in Us and The Partnership Agreement Amendment of the Partnership Agreement.

Partnership Agreement Modification of Fiduciary Duties

Our partnership agreement limits the liability of our general partner and reduces the fiduciary duties it owes to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions that might otherwise constitute a breach of the fiduciary duties that our general partner owes to our unitholders. By purchasing a common unit, our unitholders agree to be bound by the terms of our partnership agreement and, pursuant to the terms of our partnership agreement, are treated as having

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consented to various actions contemplated in our partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary or other duties under Delaware law. Please read Conflicts of Interest and Fiduciary Duties Fiduciary Duties for a description of the fiduciary duties imposed on our general partner by Delaware law, the material modifications of these duties contained in our partnership agreement and certain legal rights and remedies available to our unitholders.

Implication of Being an Emerging Growth Company

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. An emerging growth company may take advantage of specified reduced reporting and other regulatory requirements for up to five years that are otherwise applicable generally to public companies. These provisions include:

- a requirement to present only two years of audited financial statements and only two years of related Management s Discussion and Analysis;
- exemption from the auditor attestation requirement on the effectiveness of our system of internal control over financial reporting;
- exemption from the adoption of new or revised financial accounting standards until they would apply to private companies;
- exemption from compliance with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; and
- reduced disclosure about executive compensation arrangements.

We will cease to be an emerging growth company if we have more than $1.0 billion in annual revenues, have more than $700 million in market value of our limited partner interests held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

We have elected to take advantage of the applicable JOBS Act provisions, except for the following:

- we have elected to present three years of audited financial statements and three years of related Management s Discussion and Analysis rather than only two years;
- we have elected to opt out of the exemption that allows emerging growth companies to extend the transition period for complying with new or revised financial accounting standards (this election is irrevocable);
- we have elected to comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; and
- we have elected to make full disclosure about executive compensation arrangements.

Accordingly, the information that we provide you may be different than what you may receive from other public companies in which you hold equity interests.

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The Offering

Common units offered by us	1,000,000 common units. As described below, if the underwriters exercise their option to purchase additional common units, such units will be offered exclusively by the Selling Unitholders on a pro rata basis.
Common units offered by the Selling Unitholders	3,000,000 common units, or 3,600,000 common units if the underwriters exercise in full their option to purchase additional common units, which in each case will be offered by the Selling Unitholders on a pro rata basis, in proportion to their interests in us.
	Immediately before this offering, Yorktown owned 8,691,468 common units, representing an approximate 48.5% limited partner interest in us. Following this offering, Yorktown will own 5,691,468 common units, or 5,091,468 common units if the underwriters exercise in full their option to purchase additional common units, representing an approximate 30.1% and 26.9% limited partner interest in us, respectively.
Units outstanding after this offering	18,939,549 common units.
Use of proceeds	We intend to use the net proceeds of approximately $20.2 million from this offering, after deducting underwriting discounts and estimated expenses, to repay approximately $20.2 million of indebtedness outstanding under our credit facility.
	We will not receive any proceeds from the sale of common units by the Selling Unitholders, including any proceeds from the sale of common units by the Selling Unitholders if the underwriters exercise in whole or in part their option to purchase additional common units.
	Affiliates of certain of the underwriters are lenders under our credit facility and accordingly, will receive a substantial portion of the proceeds from this offering. Please read Underwriting.
Cash distributions	We paid a quarterly distribution of $0.475 per unit for the second quarter of 2012 on all common and general partner units ($1.90 per unit on an annualized basis) on August 14, 2012 to unitholders of record as of August 7, 2012. Distributions on our units are generally paid approximately 45 days following the end of a fiscal quarter to the extent we have sufficient cash from operations, after the establishment of cash reserves and the payment of fees and expenses.
	There is no guarantee that unitholders will receive a quarterly distribution from us. We do not have a legal obligation to pay

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	distributions at our current quarterly distribution rate or at any other rate except as provided in our partnership agreement.
	Assuming our general partner maintains its approximate 2.0% general partner interest in us, our partnership agreement requires that we distribute approximately 98.0% of our available cash each quarter to the holders of our common units, pro rata, and approximately 2.0% to our general partner.
	Unlike many publicly traded limited partnerships, our general partner is not entitled to any incentive distributions, and we do not have any subordinated units.
Issuance of additional units	We can issue an unlimited number of additional units, including units that are senior to the common units in right of distributions, liquidation and voting, on terms and conditions determined by our general partner, without the approval of our unitholders. Please read Units Eligible for Future Sale and The Partnership Agreement Issuance of Additional Interests.
Limited voting rights	Our general partner manages us and operates our business. Unlike stockholders of a corporation, our unitholders have only limited voting rights on matters affecting our business. Our unitholders have no right to elect our general partner or its board of directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3$% of the outstanding units, including any units owned by our general partner and its affiliates. Following this offering, the Founders and Yorktown will own an aggregate of approximately 36.0% of our common units (or approximately 32.8% of our common units if the underwriters exercise their option to purchase additional common units in full) and, therefore, will be able to prevent the removal of our general partner. Please read The Partnership Agreement Limited Voting Rights.
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a purchase price not less than the then-current market price of the common units, as calculated pursuant to the terms of our partnership agreement. Following this offering, the Founders will own an aggregate of approximately 5.9% of our common units. Please read The Partnership Agreement Limited Call Right.
Eligible Holders and redemption	Units held by persons who our general partner determines are not Eligible Holders will be subject to redemption. As used herein, an Eligible Holder means any person or entity qualified to hold an interest in oil and natural gas leases on federal lands. If, following

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	a request by our general partner, a transferee or unitholder, as the case may be, does not properly complete a recertification for any reason, we will have the right to redeem the units held by such person at the then-current market price of the units held by such person. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read Description of the Common Units Transfer Agent and Registrar Transfer of Common Units and The Partnership Agreement Non-Citizen Unitholders; Redemption.
Estimated ratio of taxable income to distributions	We estimate that if our unitholders own the common units purchased in this offering through the record date for distributions for the period ending December 31, 2014, such unitholders will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than 45% of the cash distributed to such unitholders with respect to that period. Please read Material Tax Consequences Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions for the basis of this estimate.
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read Material Tax Consequences.
Listing and trading symbol	Our common units are listed on the NASDAQ Global Market under the symbol MCEP.

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Summary Historical Financial Data

The following table shows summary financial data of us and our predecessor for the periods and as of the dates indicated. The summary financial data as of and for the year ended June 30, 2009 is derived from the audited consolidated financial statements of our predecessor included elsewhere in this prospectus. The summary financial data as of and for the years ended December 31, 2010 and 2011 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The summary financial data as of any for the six months ended December 31, 2009 is derived from our audited Consolidated Statements of Operations and Statements of Cash Flows included elsewhere in this prospectus, except for the balance sheet data which is derived from our audited consolidated balance sheet not included in this prospectus. The summary financial data as of and for the six months ended June 30, 2011 and 2012 is derived from our unaudited consolidated financial statements included elsewhere in this prospectus.

You should read the following table in conjunction with Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations, the audited historical consolidated financial statements of Mid-Con Energy Partners, LP and our predecessor and the unaudited consolidated financial statements of Mid-Con Energy Partners, LP and the notes thereto included elsewhere in this prospectus. Among other things, those historical consolidated financial statements and unaudited consolidated financial statements include more detailed information regarding the basis of presentation for the following information.

The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in evaluating the financial performance and liquidity of our business. This measure is not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain this measure below and reconcile it to the most directly comparable financial measures calculated and presented in accordance with GAAP.

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	Mid-Con Energy Corporation (consolidated)		Mid-Con Energy Partners, LP			
	Year Ended June 30,	Six Months Ended December 31,	Year Ended December 31,		Six Months Ended June 30,	
	2009	2009	2010	2011	2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil sales	$ 10,246	$ 5,729	$ 16,853	$ 36,813	$ 15,609	$ 28,998
Natural gas sales	2,172	743	1,418	1,218	658	353
Realized gain (loss) on derivatives, net	(669)	(350)	(90)	(2,157)	(715)	769
Unrealized gain (loss) on derivatives, net	1,679	(147)	(707)	3,437	1,046	9,741
Total revenues	13,428	5,975	17,474	39,311	16,598	39,861
Operating costs and expenses:						
Lease operating expenses	5,369	2,431	6,237	8,491	3,550	4,725
Oil and gas production taxes	631	269	822	1,869	656	713
Dry holes and abandonments of unproved properties			1,418	813	772	
Geological and geophysical	507		394	172		
Depreciation, depletion and amortization	2,293	2,552	5,851	7,160	2,418	4,709
Accretion of discount on asset retirement obligations	78	58	127	78	32	57
General and administrative	1,767	704	982	1,924	534	4,869
Impairment of proved oil and gas properties		9,208	1,886			
Total operating costs and expenses	10,645	15,222	17,717	20,507	7,962	15,073
Income (loss) from operations	2,783	(9,247)	(243)	18,804	8,636	24,788
Other income (expenses):						
Interest income and other	118	35	218	216	62	5
Interest expense	(93)	(2)	(98)	(578)	(237)	(703)
Gain on sale of assets	1		354	1,621	1,209	
Equity-based compensation				(1,671)		
Other revenue and expenses, net	298	118	847	576	576	
Tax expense current	(625)					
Tax (expense) benefit deferred	502					
Net income (loss)	$ 2,984	$ (9,096)	$ 1,078	$ 18,968	$ 10,246	$ 24,090
Net income per limited partner unit (basic and diluted)		$ (0.51)	$ 0.06	$ 1.05	$ 0.57	$ 1.33
Weighted average number of limited partner units outstanding (basic and diluted)		17,640	17,640	17,640	17,640	17,790
Other Financial Data:						
Adjusted EBITDA	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 10,935	$ 965	$ 11,798	$ 24,113	$ 5,192	$ 24,384
Investing activities	(12,448)	(5,018)	(22,726)	(42,045)	(13,351)	(23,992)

Financing activities	4,841	(1,164)	10,387	17,938	8,377	3,344

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	Mid-Con Energy Partners, LP				
	As of December 31,			As of June 30,	
	2009	2010	2011	2011 (unaudited)	2012 (unaudited)
	(in thousands)				
Balance Sheet Data:					
Working capital(1)	$ 2,420	$ (1,256)	$ 2,361	$ 4,383	$ 11,879
Total assets	40,496	56,867	96,611	72,390	125,148
Total debt	337	5,513	45,000	13,310	58,000
Total Equity	36,779	43,072	43,349	56,098	60,473

(1) For 2010, excludes $5.3 million of current maturities under our predecessor s credit facilities. The maturity date for these facilities was subsequently extended to December 2013.

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Non-GAAP Financial Measures

We include in this prospectus 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, our most directly comparable financial measures calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income (loss):

Plus:

- income tax expense (benefit), if any;
- interest expense;
- depreciation, depletion and amortization;
- accretion of discount on asset retirement obligations;
- unrealized losses on commodity derivative contracts;
- impairment expenses;
- dry hole costs and abandonments of unproved properties;
- equity-based compensation; and
- loss on sale of assets;

Less:

- interest income;
- unrealized gains on commodity derivative contracts; and
- gain on sale of assets.

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 cash flow available to pay distributions to our unitholders, develop existing reserves or acquire additional oil properties.

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. 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. The following table presents our reconciliation of Adjusted EBITDA to Net Income. 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.

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Reconciliation of Adjusted EBITDA to Net Income

	Mid-Con Energy Corporation (consolidated)		Mid-Con Energy Partners, LP			
	Year Ended June 30, 2009	Six Months Ended December 31, 2009	Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Net income (loss)	$ 2,984	$ (9,096)	$ 1,078	$ 18,968	$ 10,246	$ 24,090
Tax expense (benefit) deferred	(502)					
Tax expense current	625					
Interest expense	93	2	98	578	237	703
Depreciation, depletion and amortization	2,293	2,552	5,851	7,160	2,418	4,709
Accretion of discount on asset retirement obligations	78	58	127	78	32	57
Unrealized (gain) loss on derivatives, net	(1,679)	147	707	(3,437)	(1,046)	(9,741)
Impairment of proved oil and gas properties		9,208	1,886			
Dry holes and abandonments of unproved properties			1,418	813	772	
Gain on sale of assets	(1)		(354)	(1,621)	(1,209)	
Equity-based compensation				1,671		2,690
Interest income	(118)	(35)	(218)	(216)	(62)	(5)
Adjusted EBITDA	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503

Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities

	Mid-Con Energy Corporation (consolidated)		Mid-Con Energy Partners, LP			
	Year Ended June 30, 2009	Six Months Ended December 31, 2009	Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Net cash provided by operating activities	$ 10,935	$ 965	$ 11,798	$ 24,113	$ 5,192	$ 24,384
Amortization of debt placement fees						(54)
Change in working capital	(7,762)	1,904	(1,085)	(481)	6,021	(2,525)
Tax expense current	625					
Interest expense	93	2	98	578	237	703
Interest income	(118)	(35)	(218)	(216)	(62)	(5)
Adjusted EBITDA	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503

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Summary Historical Reserve and Operating Data

The following table presents summary data with respect to our estimated net proved oil and natural gas reserves that we own and the standardized measure amounts associated with those estimated proved reserves as of December 31, 2010 and as of December 31, 2011, both based on reserve reports prepared by our internal reserve engineers and audited by Cawley, Gillespie & Associates, Inc., our independent reserve engineers.

These reserve estimates were prepared in accordance with the SEC s rules regarding oil and natural gas reserve reporting that are currently in effect. From December 31, 2010 to December 31, 2011 our proved reserves increased by approximately 2.8 MMBoe, or 39%. Total proved reserves increased by approximately 0.9 MMBoe from acquisitions in the Hugoton Basin and Northeastern Oklahoma core areas; 0.8 MMBoe from waterflood expansion in the Northeastern Oklahoma core area; 0.7 MMBoe from infill drilling in the Southern Oklahoma core area; 0.7 MMBoe from drilling and workovers in the Northeastern Oklahoma core area and (0.3) MMBoe in net performance revisions for all of our properties. We spent a total of $19.3 million and $30.0 million in capital expenditures for the year ended December 31, 2010 and the year ended December 31, 2011, respectively, which contributed to the increase in our December 31, 2011 proved reserves.

From December 31, 2010 to December 31, 2011 our proved developed reserves increased by approximately 3.1 MMBoe, or 82%. Proved developed reserves increased in our Southern Oklahoma core area by 0.9 MMBoe from development drilling and 0.7 MMBoe in performance revisions; in the Hugoton Basin core area by 0.7 MMBoe from the acquisition of the War Party I and II Units; in our Northeastern Oklahoma core area by 0.2 MMBoe from acquisitions, 0.7 MMBoe from infill drilling and workovers and (0.1) MMBoe in net performance revisions for the Hugoton Basin and Northeastern Oklahoma core areas and other properties.

During the year ended December 31, 2011, we spent approximately $21.9 million in our Southern Oklahoma core area resulting in production increases and reclassifications of 0.9 MMBoe from proved undeveloped reserves to proved developed reserves, which contributed to the 1.6 MMBoe increase in proved developed reserves in our Southern Oklahoma core area discussed in the prior paragraph. Additionally, we spent approximately $13.2 million during the year ended December 31, 2011 to acquire new leases in the Hugoton Basin and Northeastern Oklahoma. We spent another $2.4 million on workover activities and $3.4 million on drilling during the year ended December 31, 2011 in Northeastern Oklahoma.

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For a discussion of risks associated with internal reserve estimates, please read Risk Factors Risks Related to Our Business 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. Please also read Management s Discussion and Analysis of Financial Condition and Results of Operations, Business and Properties Oil and Natural Gas Reserves and Production Estimated Proved Reserves, and the summary of our reserve audits dated December 31, 2010 and December 31, 2011 in evaluating the material presented below.

	As of December 31, 2010	As of December 31, 2011
Reserve Data:		
Estimated proved reserves:		
Oil (MBbl)	7,007	9,936
Natural Gas (MMcf)	1,346	676
Total (MBoe)	7,231	10,049
Proved developed (MBoe)	3,825	6,948
Oil (MBbl)	3,601	6,835
Natural Gas (MMcf)	1,346	676
Proved undeveloped (MBoe)	3,406	3,101
Oil (MBbl)	3,406	3,101
Natural Gas (MMcf)		
Proved developed reserves as a percentage of total proved reserves	52.9%	69.1%
Standardized Measure (in millions)(1)	$ 183.7	$ 328.2
Oil and Natural Gas Prices(2):		
Oil NYMEX WTI per Bbl	$ 79.43	$ 96.19
Natural gas NYMEX Henry Hub per MMBtu	$ 4.37	$ 4.11

(1) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities, as codified in ASC Topic 932, Extractive Activities Oil and Gas. Because we were not subject to federal or state income taxes for the periods presented, we make no provision for federal or state income taxes in the calculation of our standardized measure. For a description of our commodity derivative contracts, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Derivative Contracts.

(2) Our estimated net proved reserves and related standardized measure 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 prices for the prior twelve months were $79.43 per Bbl for oil and $4.37 per MMBtu for natural gas at December 31, 2010 and $96.19 per Bbl for oil and $4.11 per MMBtu for natural gas at December 31, 2011. 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. For the year ended December 31, 2010, the relevant average realized prices for oil and natural gas were $73.92

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per Bbl and $7.42 per Mcf, respectively. For the year ended December 31, 2011, the relevant average realized prices for oil and natural gas were $90.45 per Bbl and $7.43 per Mcf, respectively. Realized natural gas sales price per Mcf includes the sale of natural gas liquids for both the year ended December 31, 2010 and the year ended December 31, 2011.

	Year Ended December 31, 2011	Six Months Ended June 30, 2012
Production and operating data:		
Net production volumes:		
Oil (MBbls)	407	304
Natural gas (MMcf)	164	60
Total (MBoe)	434	314
Average net production (Boe/d)	1,191	1,725
Average sales price:(1)		
Oil (per Bbl)	$ 90.45	$ 95.39
Natural gas (per Mcf)(2)	$ 7.43	$ 5.88
Average price per Boe	$ 87.63	$ 93.47
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 19.56	$ 15.05
Production taxes	$ 4.31	$ 2.27
General and administrative and other(3)	$ 4.43	$ 15.51
Depreciation, depletion and amortization	$ 15.66	$ 15.00

(1) Prices do not include the effects of derivative cash settlements.

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

(3) General and administrative expenses include non-cash, equity-based compensation for the six months ended June 30, 2012. We had no non-cash, equity-based compensation expense for the year ended December 31, 2011.

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RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation. Prospective unitholders should carefully consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and our unitholders could lose all or part of their investment.

Risks Related to Our Business

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

We may not have sufficient available cash each quarter to pay any distributions to our unitholders. Under the terms of our partnership agreement, the amount of cash available for distribution 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;
- the amount and timing of settlements on our commodity derivative contracts;
- 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 will depend on the amount of our outstanding indebtedness and the applicable interest rate.

Further, the amount of cash we have available for distribution depends primarily on our cash flow, including cash from financial reserves and borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net income for financial accounting purposes.

A decline in oil prices, or an increase in the differential between the NYMEX or other benchmark prices of oil and the wellhead price we receive for our production, will cause a decline in our cash flow from operations, which could cause us to reduce our distributions or cease paying distributions altogether.

Lower oil prices may decrease our revenues and, therefore, our cash available for distribution to our unitholders. Historically, oil prices have been extremely volatile. For example, for the five years ended December 31, 2011, the NYMEX WTI oil price ranged from a high of $145.29 per Bbl to a low of $33.87 per Bbl. A significant decrease in commodity prices may cause us to reduce the distributions we pay to our unitholders or to cease paying distributions altogether.

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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 that are used for calculating hedge positions, such as NYMEX. 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 and remain depressed for a prolonged period, production from a significant portion of our oil properties may become uneconomic and cause write downs of the value of such oil properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

Significantly lower oil prices may render many of our development projects uneconomic and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base and ability to borrow to fund our operations or make distributions to our unitholders. As a result, we may reduce the amount of distributions paid to our unitholders or cease paying distributions. In addition, a significant or sustained decline in oil prices could hinder our ability to effectively execute our hedging strategy. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil properties. In addition, if our estimates of drilling 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 as 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 removing the impact of commodity price volatility from our cash flow, which could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders.

We generally intend to hedge a significant 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 prices at the time we enter into these transactions, which may be substantially higher or lower than current oil prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil prices received for our future production.

Our credit facility may hinder our ability to effectively execute our hedging strategy. To the extent our credit facility limits the maximum percentage of our production that we can hedge or the duration of those hedges, we may be unable to enter into additional commodity derivative contracts during favorable market conditions and, thus, unable to lock in attractive future prices for our product sales. Conversely, while our credit facility does not currently require us to hedge a minimum percentage of our production, it may cause us to enter into commodity derivative contracts at inopportune times. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

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

Many of our 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

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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 derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty s liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

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

We may be unable to sustain our current quarterly distribution rate of $0.475 per unit 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 flow and ability to make distributions are highly dependent on our success in 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 may require substantial capital expenditures, which could reduce our cash available for distribution and could materially affect our ability to make distributions to our unitholders.

We may be required to make substantial capital expenditures from time to time in connection with the production of our oil reserves. Further, if the borrowing base under our 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 the expected levels so as to generate an amount of cash necessary to make distributions to our unitholders.

Developing and producing oil is a costly and high-risk activity with many uncertainties that could adversely affect our financial condition or results of operations and, as a result, our ability to pay 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 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;
- unitization difficulties;
- pipe or cement failures, casing collapses or other downhole failures;

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- 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 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 such 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 prices used in our December 31, 2011 reserve report had been $10.00 less per barrel for oil, the standardized measure of our estimated proved reserves, without asset retirement obligations, as of that date would have decreased by $48.0 million, from $328.2 million to $280.9 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.

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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 flow 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 flow 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 Standards 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 pay or increase distributions will be limited.

Our ability to grow 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 increase or possibly even to maintain our level of 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;

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- 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 from the Mid-Con Affiliates) may be incomplete because it generally is not feasible to perform an in-depth review of such properties, given the time constraints imposed by most sellers. Even a detailed review of the records associated with properties owned by third parties 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 operating 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 and Colorado. 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.

Sales to a subsidiary of Sunoco Logistics Partners, L.P., or Sunoco Logistics, accounted for approximately 86% of our total sales revenues for the year ended December 31, 2011. In 2012, we entered into crude oil purchase agreements with Enterprise Crude Oil, Inc., or Enterprise, Vitol, Inc., or Vitol, and Coffeyville Resources Refining and Marketing, LLC, or Coffeyville Resources. For the six months ended June 30, 2012, sales to Enterprise, Sunoco Logistics and Vitol accounted for approximately 54%, 37% and 2%, respectively, of our total sales. We do not currently sell any production to Sunoco Logistics. After June 30, 2012, we expect that Vitol and Coffeyville Resources will each account for significantly higher percentages of our total sales. Our production is and will continue to be marketed by our affiliate, Mid-Con Energy Operating, under these crude oil purchase contracts. To the extent that any of our current purchasers reduce the volumes 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 at the then-current distribution rate or at all.

In addition, a failure by Enterprise, Vitol, Coffeyville Resources or any of our other 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

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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, where most of our properties are located, 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 may be unable to compete effectively with larger companies, which may 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. 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. 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. 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 during periods of low 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 adjoining our interests could take actions, such as drilling additional wells, which 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.

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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.

We may be unable to pay distributions at our current quarterly distribution rate without borrowing under our credit facility. If we use borrowings under our 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, will reduce our cash available for distribution on our units and will have a material adverse effect on our business, financial condition and results of operations. If we borrow to pay distributions to our unitholders during periods of low commodity prices and commodity prices remain low, we may have to reduce our distribution to our unitholders to avoid excessive leverage.

Our 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 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 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 will 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 credit facility will be secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit facility, the lenders could seek to foreclose on our assets.

The total amount we are able to borrow under our 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. Our lenders reaffirmed the borrowing base at $100.0 million on September 20, 2012. Any substantial or sustained decline in commodity prices would likely lead to a decrease in our borrowing base upon redetermination and, in such case, we could be required to repay any indebtedness in excess of the borrowing base. In the future, we may be unable to access sufficient capital under our credit facility as a result of a decrease in our borrowing base due to a subsequent borrowing base redetermination.

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

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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 as 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 Environmental Protection Agency, or the EPA, published its findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another which requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. On May 12, 2010, the EPA also issued a new tailoring rule, which makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. On September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. In addition, on November 30, 2010, the EPA published a final rule that expands its existing GHG emissions reporting rule to include certain owners and operators of onshore oil and natural gas production to monitor GHG emissions beginning in 2011 and to report those emissions beginning in 2012. 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 GHGs, 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 GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur significant costs to reduce emissions of GHGs associated with operations or could adversely affect demand for our production.

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.

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Strict, joint and several liability 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.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, enacted in July 2010, establishes a new regulatory framework for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on a derivative clearing organization and traded on an exchange or a swap execution facility, and cash collateral will have to be posted. The Dodd-Frank Act requires the Commodities Futures Trading Commission, or the CFTC, federal regulators of banks and other financial institutions, or the Prudential Regulators, and the SEC to promulgate the rules implementing the Dodd-Frank Act, within 360 days from the date of enactment. The CFTC issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The CFTC s position limits rules will become effective on October 12, 2012, although there is a pending legal proceeding seeking to enjoin those rules. The rules will impose certain position limits for spot month positions; at this time the CFTC has not established limits for non-spot month or combined month positions. Certain CFTC reporting and recordkeeping rules will become effective beginning October 12, 2012, for swap dealer entities. End user compliance with reporting rules and permanent recordkeeping rules is expected to begin 180 days after October 12, 2012.

Depending on the rules and definitions ultimately adopted by the CFTC, the SEC and the Prudential Regulators, we might in the future be required to post cash collateral for our commodities derivative transactions. Posting of cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. We are at risk until the regulators adopt rules and definitions that confirm that companies like us are not required to post cash collateral for our derivative hedging contracts. Even if we are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Dodd-Frank Act s new requirements, and the costs of their compliance will likely be passed on to customers, including us, thus decreasing the benefits to us of hedging transactions and reducing the profitability of our cash flows. In addition, the Dodd-Frank Act may also require our contractual counterparties to our derivative contracts to spin-off their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty. These changes might not only increase costs, but could also reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or reduce our ability to monetize or restructure our existing derivative contracts and potentially increase our exposure to less creditworthy counterparties.

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

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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 recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. 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. On July 1, 2012, the Oklahoma Corporation Commission adopted new 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. Certain proprietary information may be excluded from an operator s disclosure. The new disclosures apply to horizontal wells that are hydraulically fractured on or after January 1, 2013 and to other wells that are hydraulically fractured on or after January 1, 2014. Additionally, some states 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. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation 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, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA recently announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. In addition, 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. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. 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.

Risks Inherent in an Investment in Us

In addition to the risk factors presented below, there are other risk factors related to conflicts of interests and our general partner s fiduciary duties inherent in an investment in us. See Conflicts of Interest and Fiduciary Duties for a discussion of those risks.

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Our general partner controls us, and immediately following this offering, the Founders and Yorktown will own an approximate 36.0% limited partner interest in us, or an approximate 32.8% in us if the underwriters exercise in full their option to purchase additional common units. 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. Immediately following this offering, the Founders and Yorktown will own an approximate 36.0% limited partner interest in us, or an approximate 32.8% limited partner interest in us if the underwriters exercise in full their option to purchase additional common units. 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 Affiliates and will continue to have economic interests in, as well as management and fiduciary duties to, the Mid-Con Affiliates. 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 Affiliates 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 common 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 Affiliates 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 Affiliates 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 Affiliates 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 Affiliates 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 also provides these services to the Mid-Con Affiliates;

- 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 has limited 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.

Please read Certain Relationships and Related Party Transactions and Conflicts of Interest and Fiduciary Duties.

Our partnership agreement limits our general partner s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, which allows our general partner to consider only the interests and factors that it desires, without a duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns and its determination whether or not to consent to any merger or consolidation involving us or to any amendment to the partnership agreement;

provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith;

generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must either be (i) on terms no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) must be fair and reasonable to us, as determined by our general partner in good faith. In determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

provides that in resolving conflicts of interest, it will be presumed that in making its decision our general partner s board of directors or the conflicts committee of our general partner s board of

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directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

By purchasing a common unit, a unitholder is bound by the provisions in the partnership agreement, including the provisions discussed above.

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 Affiliates, 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 also provides substantially similar services and personnel to the Mid-Con Affiliates 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 Affiliates 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 our cash distributions to our 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. In addition, if the amount of any future distribution is less than the current quarterly distribution rate, public unitholders will not have any right to receive any payments of 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. Please read Description of the Common Units Transfer Agent and Registrar Transfer of Common Units and The Partnership Agreement Non-Citizen Unitholders; Redemption.

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 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. Please read Management Management of Mid-Con Energy Partners, LP and Certain Relationships and Related Party Transactions. Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or address other matters routinely handled 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, they cannot remove our general partner without its consent.

The public unitholders are currently unable to remove our general partner without its consent because affiliates of our general partner and Yorktown own sufficient units to prevent the removal of our general partner. The vote of the holders of at least $66^2/_3$% of all outstanding units is required to remove our general partner. Immediately following this offering, the Founders and Yorktown will own approximately 36.0% of our outstanding common units, or approximately 32.8% of our outstanding common units if the underwriters exercise in full their option to purchase additional common units, which will enable those holders, collectively, to prevent the removal of our general partner.

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

Our general partner may transfer its general partner 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

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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 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 flow, 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.

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 significant unitholders may have an adverse impact on the trading price of our common units.

Following this offering, the Founders and Yorktown will own 6,816,660 common units or approximately 36.0% of our outstanding common units, or 6,216,660 common units or approximately 32.8% of our outstanding common units if the underwriters exercise their option to purchase additional common units in full. Sales of these units or of other substantial amounts of our common units in the public market 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.

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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.

Please read The Partnership Agreement Limited Liability for a discussion of the implications of the limitations of liability on a unitholder.

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 unitholders may have limited liquidity for their common units, a trading market may not continue for the common units and our unitholders may not be able to resell their common units at their initial purchase price.

Our common units are thinly traded on the public market. We do not know how liquid the trading market for our common units will be after this offering. Our unitholders may not be able to resell their common units at or above their initial purchase price. Additionally, a lack of liquidity would likely result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

If our common unit price declines, our unitholders could lose a significant part of their investment.

The market price of our common units is subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in commodity prices;

- changes in interest rates;

- changes in securities analysts recommendations and their estimates of our financial performance;

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- public reaction to our press releases, announcements and filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and natural gas companies;
- variations in the amount of our quarterly cash distributions to our unitholders;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

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 maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in our 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.

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Tax Risks to Unitholders

In addition to reading the following risk factors, prospective unitholders should read Material Tax Consequences for a more complete discussion of the expected material federal income tax consequences of owning and disposing of our units.

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the 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 the units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based on our current operations that we are so treated, a change in our business (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 income tax at varying rates. Distributions to unitholders would generally be taxed again as corporate distributions, 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 flow 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 are 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 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, the Obama Administration and members of Congress have considered substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Although 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.

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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.

Legislation has been proposed that would, if enacted, make significant changes to United States tax laws, including the elimination of 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.

We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or the positions we take. 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.

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 those 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 their 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 IDC 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. Please read Material Tax Consequences Disposition of Units Recognition of Gain or Loss.

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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, or 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 returns. Please read Material Tax Consequences Tax Consequences of Unit Ownership Section 754 Election for a further discussion of the effect of the depreciation, depletion and amortization positions we will adopt.

We will 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 will 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 use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Andrews Kurth LLP has not rendered an opinion with respect to whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations. Please read Material Tax Consequences Disposition of Units Allocations Between Transferors and Transferees.

A unitholder whose units are loaned to a short seller to effect 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. Andrews Kurth LLP has not rendered an opinion regarding the treatment of a unitholder

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where units are loaned to a short seller to effect a short sale of units; therefore, 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.

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 should 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. Please read Material Tax Consequences Disposition of Units Constructive Termination for a discussion of the consequences of our termination for federal income tax purposes.

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 likely will 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 Oklahoma and Colorado, each of which currently imposes a personal income tax on individuals. These states also 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. Andrews Kurth LLP has not rendered an opinion on the state or local tax consequences of an investment in our units.

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USE OF PROCEEDS

We intend to use the estimated net proceeds of approximately $20.2 million from our sale of common units in this offering, after deducting underwriting discounts and estimated offering expenses, to repay approximately $20.2 million of indebtedness outstanding under our credit facility. Borrowings under our credit facility were used for short-term working capital needs and acquisitions. The borrowings bear interest at approximately 2.5%, and are due upon the expiration of our credit facility in December 2016.

Affiliates of RBC Capital Markets, LLC and Wells Fargo Securities, LLC are lenders under our credit facility, and, accordingly, will receive a substantial portion of the net proceeds from this offering. Please read Underwriting.

We will not receive any of the proceeds from the sale of common units by the Selling Unitholders, including any common units sold by the Selling Unitholders if the underwriters exercise their option to purchase additional common units, in whole or in part.

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CAPITALIZATION

The following table shows our:

historical capitalization as of June 30, 2012; and

as adjusted capitalization as of June 30, 2012, which gives effect to this offering and the application of the net proceeds from this offering as described under Use of Proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, our historical and unaudited financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of June 30, 2012	
	Actual	As Adjusted
	(in thousands)	
Cash and cash equivalents	$ 3,964	$ 3,964
Long-term debt	$ 58,000	$ 37,800
Equity:		
General partner interest	1,638	1,595
Total partners equity	60,473	80,673
Total capitalization	$ 118,473	$ 118,473

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PRICE RANGE OF COMMON UNITS AND DISTRIBUTION

Our common units are listed and traded on the NASDAQ Global Market under the symbol MCEP. Our common units began trading on December 15, 2011 at an initial public offering price of $18.00 per common unit. As reported by the NASDAQ Global Market, the following table shows the low and high sales prices per common unit for the periods indicated. Distributions are shown in the quarter for which they were paid:

	Low	High	Cash distribution per unit
2012:			
Fourth quarter (through October 12, 2012)	$ 21.67	$ 22.84	$ (2)
Third quarter	$ 20.31	$ 24.12	$ 0.485(3)
Second quarter	$ 17.87	$ 24.66	$ 0.475
First quarter	$ 18.25	$ 25.18	$ 0.475
2011:			
Fourth quarter(1)	$ 17.25	$ 18.87	$ 0.057(4)

(1) From December 15, 2011, the day our common units began trading on the NASDAQ Global Market, through December 31, 2011.

(2) The distribution payable for the fourth quarter of 2012 has not been declared or paid.

(3) On October 15, 2012, our general partner declared a cash distribution of $0.485 per unit ($1.94 per unit on an annualized basis) for the third quarter of 2012, an increase of $0.01 from the previous quarter, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 7, 2012.

(4) Reflects the pro rata portion of the $0.475 quarterly distribution per unit paid, representing the period from the day after the December 20, 2011 closing of our initial public offering through December 31, 2011. An identical cash distribution was paid on all outstanding common and general partner units.

The last reported sale price of our common units on the NASDAQ Global Market on October 12, 2012 was $22.84. As of October 11, 2012, there were approximately 25 holders of record of our common units. This number does not include owners for whom common units may be held in street name or whose common units are restricted.

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SELECTED HISTORICAL FINANCIAL DATA

The following table shows selected financial data of us and our predecessor for the periods and as of the dates indicated. The selected financial data as of and for the years ended June 30, 2007 and 2008 is derived from the audited consolidated financial statements of our predecessor not included in this prospectus. The selected financial data as of and for the year ended June 30, 2009 is derived from the audited consolidated financial statements of our predecessor included elsewhere in this prospectus. The selected financial data as of and for the years ended December 31, 2010 and 2011 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected financial data as of and for the six months ended December 31, 2009 is derived from our audited Consolidated Statements of Operations and Statements of Cash Flows included elsewhere in this prospectus except for the balance sheet data which is derived from our audited consolidated balance sheet not included in this prospectus. The selected financial data for the six months ended June 30, 2011 and 2012 is derived from our unaudited consolidated financial statements. The selected financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations, the historical consolidated financial statements of Mid-Con Energy Partners, LP and our predecessor and the unaudited condensed financial statements of Mid-Con Energy Partners, LP and the notes thereto included elsewhere in this prospectus.

The following table represents a non-GAAP financial measure, Adjusted EBITDA, which we use in evaluating the financial performance and liquidity of our business. This measure is not calculated or presented in accordance with GAAP. We explain this measure below and reconcile it to the most directly comparable financial measures calculated and presented in accordance with GAAP.

	Mid-Con Energy Corporation (consolidated)			Mid-Con Energy Partners, LP				
	Year Ended June 30,			Six Months Ended December 31,	Year Ended December 31,		Six Months Ended June 30,	
Statement of Operations Data:	2007	2008	2009	2009	2010	2011	2011 (unaudited)	2012 (unaudited)
					(in thousands)			
Revenues:								
Oil sales	$ 6,944	$ 13,667	$ 10,246	$ 5,729	$ 16,853	$ 36,813	$ 15,609	$ 28,998
Natural gas sales	64	618	2,172	743	1,418	1,218	658	353
Realized gain (loss) on derivatives, net	558	(804)	(669)	(350)	(90)	(2,157)	(715)	769
Unrealized gain (loss) on derivatives, net	45	(2,035)	1,679	(147)	(707)	3,437	1,046	9,741
Total revenues	7,611	11,446	13,428	5,975	17,474	39,311	16,598	39,861
Operating costs and expenses:								
Lease operating expenses	3,429	5,005	5,369	2,431	6,237	8,491	3,550	4,725
Oil and gas production taxes	478	946	631	269	822	1,869	656	713
Dry holes and abandonments of unproved properties	220				1,418	813	772	
Geological and geophysical	342	1,296	507		394	172		
Depreciation, depletion and amortization	924	1,599	2,293	2,552	5,851	7,160	2,418	4,709
Accretion of discount on asset retirement obligations	35	56	78	58	127	78	32	57
General and administrative	1,805	1,871	1,767	704	982	1,924	534	4,869
Impairment of proved oil and gas properties				9,208	1,886			
Total operating costs and expenses	7,233	10,773	10,645	15,222	17,717	20,507	7,962	15,073
Income (loss) from operations	378	673	2,783	(9,247)	(243)	18,804	8,636	24,788

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Statement of Operations Data:	Mid-Con Energy Corporation (consolidated) Year Ended June 30, 2007	2008	2009	Six Months Ended December 31, 2009	Mid-Con Energy Partners, LP Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011 (unaudited)	2012 (unaudited)
					(in thousands)			
Other income (expenses):								
Interest income and other	126	115	118	35	218	216	62	5
Interest expense	(11)	(3)	(93)	(2)	(98)	(578)	(237)	(703)
Gain on sale of assets			1		354	1,621	1,209	
Equity-based compensation						(1,671)		
Other revenue and expenses, net	439	108	298	118	847	576	576	
Tax expense current			(625)					
Tax (expense) benefit deferred	(197)	(261)	502					
Net income (loss)	$ 735	$ 632	$ 2,984	$ (9,096)	$ 1,078	$ 18,968	$ 10,246	$ 24,090
Net income per limited partner unit (basic and diluted)				$ (0.51)	$ 0.06	$ 1.05	$ 0.57	$ 1.33
Weighted average number of limited partner units outstanding (basic and diluted)				17,640	17,640	17,640	17,640	17,790
Other Financial Data:								
Adjusted EBITDA		$ 4,471	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503
Cash Flow Data:								
Net cash provided by (used in):								
Operating activities	$ 2,052	$ 4,221	$ 10,935	$ 965	$ 11,798	$ 24,113	$ 5,192	$ 24,384
Investing activities	(11,143)	(7,646)	(12,448)	(5,018)	(22,726)	(42,045)	(13,351)	(23,992)
Financing activities	9,980	147	4,841	(1,164)	10,387	17,938	8,377	3,344

Balance Sheet Data:	Mid-Con Energy Partners, LP As of December 31, 2009	2010	2011	As of June 30, 2011	2012
Working capital(1)	$ 2,420	$ (1,256)	$ 2,361	$ 4,383	$ 11,879
Total assets	40,496	56,867	96,611	72,390	125,148
Total debt	337	5,513	45,000	13,310	58,000
Equity	36,779	43,072	43,349	56,098	60,473

(1) For 2010, excludes $5.3 million of current maturities under our predecessor s credit facilities. The maturity date for these facilities was subsequently extended to December 2013.

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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 the Selected Historical Financial Data and the accompanying financial statements and related notes included elsewhere in this prospectus.

Overview

We are a Delaware limited partnership formed in July 2011 to own, operate, acquire, exploit and develop producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. 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. Through the continued development of our existing properties and through future acquisitions, we will seek to increase our reserves and production in order to maintain 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 significant portion of our production volumes through various commodity derivative contracts.

As of December 31, 2011, our total estimated proved reserves were approximately 10.0 MMBoe, of which approximately 99% were oil and 69% were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating operated 99% of our properties and 96% were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended June 30, 2012 was approximately 1,844 Boe per day and based on our December 31, 2011 audited reserves, as adjusted for average net production for the six months ended June 30, 2012, our total estimated proved reserves had a reserve-to-production ratio of approximately 15 years. As of December 31, 2011, our management team developed approximately 59% of our total reserves through new waterflood projects.

How We Evaluate Our Operations

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.

Production Volumes

Production volumes directly impact our results of operations. For more information about our production volumes, please read Historical Financial and Operating Data.

The following table presents production volumes for our properties for the years ended December 31, 2010 and 2011 and for the six months ended June 30, 2011 and 2012.

	Year Ended December 31,		Six Months Ended June 30,	
	2010	2011	2011	2012
Oil (MBbls)	228	407	167	304

Natural Gas (MMcf)	191	164	79	60
Total (MBoe)	260	434	180	314
Average Net Production (Boe/d)	710	1,191	994	1,725

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Realized Prices on the Sale of Oil

Factors Affecting the Sales Price of Oil. The price of oil generally is determined by factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. Oil prices are also heavily influenced by product quality and location relative to consuming and refining markets. The NYMEX-WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX-WTI price as a result of quality and location differentials.

Quality differentials to NYMEX-WTI prices result from the fact that oil can differ in its molecular makeup, which plays an important part in its refining and subsequent sale as petroleum products. The two primary characteristics that account for quality differentials are: (1) the oil s American Petroleum Institute, or API, gravity and (2) the oil s percentage of sulfur content by weight. In general, lighter oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value, and therefore, normally sells at a higher price than heavier oil. Oil with low sulfur content or sweet oil is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil or sour oil. The oil produced from our properties is predominately light sweet oil.

Location differentials to NYMEX-WTI prices result from variances in transportation costs based on the produced oil s proximity to the major trading, transportation and refining markets to which it is ultimately delivered. Oil that is produced close to major trading, transportation and refining markets, such as Cushing, Oklahoma, command a higher price because of lower transportation costs as compared to oil that is produced farther from such markets. Consequently, oil that is produced close to major trading, transportation and refining markets normally realizes a higher price (*i.e.*, a lower location differential to NYMEX-WTI).

Sales Contracts. For the six months ended June 30, 2012, sales to Enterprise, Sunoco Logistics and Vitol accounted for approximately 54%, 37% and 2%, respectively, of our total sales. We enter into six month crude oil purchase agreements with each of our purchasers with month-to-month extensions until either party terminates the contract with a thirty day notice. We believe this allows us to obtain favorable and more predictable pricing for our production than would otherwise be available to us if smaller amounts of our production had been sold to several purchasers based on posted prices.

Our purchase agreements with our purchasers all provide a fixed NYMEX-WTI differential for all production from an individual producing lease. Settlement under all of these purchase agreements occurs monthly, with payment being made on or about the 20th of each month for oil delivered during the previous month. The ultimate price per barrel paid to us by our purchasers is based on a daily average settling price of the near month NYMEX-WTI light sweet crude oil contract during the month in which the oil is actually delivered, minus the applicable differential.

We will continue to compare the pricing under our crude oil purchase contracts to offers from other purchasers to determine the best price in the relevant market.

Commodity Derivative Contracts. To better manage oil price fluctuations and achieve more predictable cash flow, we maintain a portfolio of hedge contracts to help protect our ability to make distributions. These instruments limit our exposure to declines in prices, but also limit our upside if prices increase. Because the prices at which we sell a substantial majority of our oil production are determined by the NYMEX-WTI futures price, our derivatives contract pricing strategy is intended to manage and reduce our exposure to NYMEX-WTI price fluctuations, and is not dependent upon or influenced by the portion of our production we sell to any of our customers.

For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of

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our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our audited proved reserves as of December 31, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, respectively.

The following table reflects, with respect to our existing commodity derivative contracts, the volumes our production covered by commodity derivative contracts and the average prices at which the production will be hedged:

	Six Months Ended December 31, 2012	**Year Ended December 31, 2013**	**2014**
Oil Derivative Contracts:			
Swap Contracts:			
Volume (Bbls/d)	1,207	1,216	1,315
Weighted Average NYMEX-WTI price per Bbl	$ 101.85	$ 100.14	$ 94.30
Put/Call Option Contracts (Collars):			
Volume (Bbls/d)	196	296	
Weighted Average Floor-Ceiling NYMEX-WTI price per Bbl	$ 100.00 $117.00	$ 97.67 108.08	$

Lease Operating Expenses

Lease operating expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water injection and disposal, and materials and supplies comprise the most significant portion of our lease operating expenses. Lease operating expenses do not include general and administrative costs, but do include ad valorem taxes. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased lease operating expenses during the time which they are performed.

A majority of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, we incur power costs in connection with various production related activities such as pumping to recover oil, separation and treatment of water produced in connection with our oil production, and re-injection of water into the oil producing formation to maintain reservoir pressure. As these costs are driven not only by volumes of oil produced but also by volumes of water produced, fields that have a high percentage of water production relative to oil production, also known as a high water cut, will experience higher power costs for each barrel of oil produced. Since a majority of our oil is produced from waterflooding, the amount of water produced will increase for a given volume of oil production over the life of these fields. In newly implemented waterflood projects, per unit lifting costs increase early in the life of the project due to production losses associated with the conversion of producing wells to water injection and the additional cost of injecting water. Once production response to injection occurs, the per unit lease operating expenses will begin to decrease as absolute costs remain relatively stable and production rates increase.

An example of decreasing per unit lease operating expenses is our Highlands Unit, where operating costs increased on an absolute basis during the twelve months ended June 30, 2012. During the same twelve month period, per unit lease operating expenses for our Highlands Unit decreased from approximately $16.41 per Boe, for the twelve months ending June 30, 2011, to $9.47 per Boe for the twelve months ended

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June 30, 2012 as production increased due to ongoing response to waterflooding and development drilling. After a waterflood project has reached peak production, the water cut will usually increase, resulting in the production of each barrel of oil becoming more expensive until, at some point, additional production becomes uneconomic.

We typically evaluate our lease operating expenses on a per Boe basis. This allows us to monitor these costs in certain fields and geographic areas to identify trends and to benchmark against other producers. For mature waterflood projects, total lease operating expenses may remain relatively stable, but due to production declines, lease operating expenses will generally increase on a per Boe basis. We believe that one of our areas of core expertise lies in reducing per unit lease operating expenses for mature high water cut waterfloods. We monitor our operations to ensure that we are incurring operating costs at the optimal level relative to our production. Accordingly, we monitor our lease operating expenses and operating costs per well to determine if any wells or properties should be shut in, recompleted or sold.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss):

Plus

- income tax expense (benefit), if any;
- interest expense;
- depreciation, depletion and amortization;
- accretion of discount on asset retirement obligations;
- unrealized losses on commodity derivative contracts;
- impairment expenses;
- dry hole costs and abandonment of unproved properties;
- equity-based compensation; and
- loss on sale of assets;

Less

- interest income;

- unrealized gains on commodity derivative contracts; and
- gain on sale of assets.

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.

Adjusted EBITDA should not be considered an alternative to net income, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. 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. For

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further discussion of the non-GAAP financial measure Adjusted EBITDA, please read Prospectus Summary Non-GAAP Financial Measures.

Outlook

Beginning in the second half of 2008, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. While oil prices have generally increased since the second quarter of 2009, the demand for oil remains mixed in foreign markets, especially in China, and the outlook and timing for a worldwide economic recovery remains uncertain for the foreseeable future and the timing of a recovery in worldwide demand for energy to pre-2008 levels is difficult to predict. As a result, it is likely that commodity prices will continue to be volatile in 2012. 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. Significant factors that may impact future commodity prices include the political and economic developments currently impacting North Africa and the Middle East in general, the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil supply through export quotas, and the overall North American oil and natural gas supply fundamentals.

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. We plan to maintain our focus primarily on adding reserves through improving the economics of producing oil from our existing fields and, secondarily, through acquisitions of additional proved reserves. We expect that acquisition opportunities may come from the Mid-Con Affiliates and also from unrelated third parties. 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.

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Historical Financial and Operating Data

The following table sets forth selected historical combined financial and operating data for us and our predecessor for the periods presented. The following table should be read in conjunction with Selected Historical Financial Data.

	Mid-Con Energy Corporation (consolidated)	Mid-Con Energy Partners, LP				
	Year Ended June 30,	Six Months Ended December 31,	Year Ended December 31,		Six Months Ended June 30,	
	2009	2009	2010	2011	2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Revenues (in thousands):						
Oil sales	$ 10,246	$ 5,729	$ 16,853	$ 36,813	$ 15,609	$ 28,998
Natural gas sales	2,172	743	1,418	1,218	658	353
Realized gain (loss) on derivatives, net	(669)	(350)	(90)	(2,157)	(715)	769
Unrealized gain (loss) on derivatives, net	1,679	(147)	(707)	3,437	1,046	9,741
Total Revenues	$ 13,428	$ 5,975	$ 17,474	$ 39,311	$ 16,598	$ 39,861
Expenses (in thousands):						
Lease operating expense	$ 5,369	$ 2,431	$ 6,237	$ 8,491	3,550	$ 4,725
Oil and gas production taxes	631	269	822	1,869	656	713
Dry holes and abandonments of unproved properties			1,418	813	772	
Depreciation, depletion and amortization(1)	2,103	2,357	5,204	6,795	2,080	4,709
General and administrative(3)	1,767	704	982	1,924	534	4,869
Impairment of proved oil and gas properties		9,208	1,886			
Interest expense	93	2	98	578	237	703
Production:						
Oil (MBbls)	153	87	228	407	167	304
Natural gas (MMcf)	341	140	191	164	79	60
Total (MBoe)	210	110	260	434	180	314
Average net production (Boe/d)	575	602	710	1,191	994	1,725
Average sales price:						
Oil (per Bbl):						
Sales price	$ 66.87	$ 65.85	$ 73.92	$ 90.45	$ 93.47	$ 95.39
Effect of realized commodity derivative instruments	$ (4.37)	$ (4.02)	$ (0.39)	$ (5.30)	$ (4.28)	$ 2.53
Realized price	$ 62.50	$ 61.83	$ 73.53	$ 85.15	$ 89.19	$ 97.92
Natural gas (per Mcf):						
Sales price(2)	$ 6.37	$ 5.31	$ 7.42	$ 7.43	$ 8.33	$ 5.88
Average unit costs per Boe:						
Lease operating expenses	$ 25.56	$ 22.10	$ 23.99	$ 19.56	$ 19.72	$ 15.05
Oil and gas production taxes	$ 3.00	$ 2.45	$ 3.16	$ 4.31	$ 3.64	$ 2.27
General and administrative expenses	$ 8.41	$ 6.40	$ 3.78	$ 4.43	$ 2.97	$ 15.51
Depreciation, depletion and amortization	$ 10.01	$ 21.43	$ 20.02	$ 15.66	$ 11.56	$ 15.00

(1) Depreciation, depletion, and amortization expenses for this table only represent the depletion expenses for the producing properties.

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

(3) General and administrative expenses include non-cash, equity-based compensation for the six months ended June 30, 2012. We had no non-cash, equity based compensation expense for the year ended December 31, 2011.

Results of Operations

Factors Impacting the Comparability of Our Financial Results

The comparability of our future results of operations to our historical results of operations and the comparability of our historical results of operations among the periods presented may be impacted by:

- Our initial public offering of 5,400,000 common units and subsequent over-allotment offering of 810,000 common units in December 2011 and January 2012, respectively;

- The drilling of 35 wells in 2010, 48 wells in 2011 and 14 wells during the six months ended June 30, 2012 on our properties in Oklahoma;

- Our sale to the Mid-Con Affiliates on June 30, 2011 of certain properties representing less than 1% of our proved reserves by value, as calculated using the standardized measure, as of September 30, 2011, and certain subsidiaries that do not own oil and natural gas reserves, including Mid-Con Energy Operating, to the Mid-Con Affiliates for aggregate consideration of $7.5 million;

- Our acquisition of the War Party I and II Units for a purchase price of $7.2 million on June 30, 2011;

- The acquisition of interests in various properties located in Oklahoma for an aggregate purchase price of approximately $6.5 million throughout the year in 2010;

- The unitization of the Ardmore and Twin Forks Units in January 2009;

- The reorganization of Mid-Con Energy Corporation into two limited liability companies in June 2009, which eliminated our corporate tax expense, and in connection therewith, the change in our fiscal year end from June 30 to December 31;

- Our acquisition in December 2011 of additional working interests in the Cushing Field for $6.0 million; and

- The acquisition in June 2012 of certain oil properties located in our Northeastern Oklahoma core area and additional working interests in our existing units in our Southern Oklahoma core area.

Six Months Ended June 30, 2012 Compared to the Six Months Ended June 30, 2011

Sales Revenues. Revenues from oil and natural gas sales for the six months ended June 30, 2012 were approximately $29.4 million as compared to approximately $16.3 million for the six months ended June 30, 2011. The increase in revenues was primarily due to an increase in daily oil production in 2012.

Our production volumes for the six months ended June 30, 2012 were 314 MBoe, or 1,725 Boe per day. In comparison, our production volumes for the six months ended June 30, 2011 were 180 MBoe, or 994 Boe per day. The increase in production volumes was primarily due to ongoing waterflood response to injection as well as the drilling programs in our Southern Oklahoma core area, and the acquisitions of

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interests in various properties located in the Hugoton Basin area, which both occurred during the second half of 2011. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the six months ended June 30, 2012 was $95.39, compared with $93.47 for the six months ended June 30, 2011.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net gain from our commodity hedging program for the six months ended June 30, 2012 of approximately $10.5 million, which was composed of a realized gain of approximately $0.8 million and an unrealized gain of approximately $9.7 million. For the six months ended June 30, 2011, we recorded a net gain from our commodity hedging program of approximately $0.3 million, which was composed of a realized loss of approximately $0.7 million and an unrealized gain of approximately $1.0 million.

Lease Operating Expenses. Our lease operating expenses were $4.7 million for the six months ended June 30, 2012, or $15.05 per Boe, compared to $3.6 million for the six months ended June 30, 2011, or approximately $19.72 per Boe. The increase in total lease operating expenses during the six months ended June 30, 2012 was primarily attributable to an increase in production resulting from our drilling programs and the increase in the number of producing wells. The decrease in lease operating expenses per Boe was due to the increased production for the six months ended June 30, 2012. Ad valorem taxes are also reflected in lease operating expenses. Ad valorem taxes are levied on our properties in Colorado and are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts, and a percentage of production equipment value.

Production Taxes. Our production taxes were $0.7 million for the six months ended June 30, 2012, or $2.27 per Boe for an effective tax rate of 2.4%, compared to $0.7 million for the six months ended June 30, 2011, or $3.64 per Boe for an effective tax rate of approximately 4.0%. The decrease in the production taxes per Boe during the six months ended June 30, 2012 was primarily due to receiving an adjustment of $0.5 million of production taxes for one of our Southern Oklahoma units for periods prior to the year 2012. The adjustment was due to the Enhanced Recovery Project Gross Production Tax Exemption. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. The State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%. A portion of our wells in Oklahoma continue to receive a reduced production rate due to Oklahoma s Enhanced Recovery Project Gross Production Tax Exemption which has been extended to July 2014.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses on producing properties for the six months ended June 30, 2012 were $4.7 million, or $15.00 per Boe produced, compared to $2.1 million, or $11.56 per Boe produced, for the six months ended June 30, 2011. The increase in depreciation, depletion and amortization expenses and average price per Boe produced was primarily due to the increase in total proved and proved developed reserves estimated at June 30, 2012 and also the increase in total asset value of $40.0 million from our drilling program that occurred in the second half of 2011, and acquisitions of properties in our Hugoton Basin and Southern Oklahoma core areas, which both occurred during the second half of 2011.

General and Administrative Expenses. Our general and administrative expenses were approximately $4.9 million for the six months ended June 30, 2012, or $15.51 per Boe produced compared to approximately $0.5 million for the six months ended June 30, 2011 or $2.97 per Boe produced. The increase in general and administrative expenses for the six months ended June 30, 2012 is primarily due to higher compensation costs related to our non-cash equity-based compensation expense of $2.7 million, higher professional fees necessary to comply with public reporting requirements and incremental costs related to the hiring of additional staff.

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Interest Expense. Our interest expense for the six months ended June 30, 2012 was $0.7 million, compared to $0.2 million for the six months ended June 30, 2011. The increase was primarily due to increased borrowings under our credit facility.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Sales Revenues. Revenues from oil and natural gas sales for the twelve months ended December 31, 2011 were approximately $38.0 million as compared to $18.3 million for the twelve months ended December 31, 2010. The increase in revenues was primarily due to an increase in daily oil production and higher sales prices during the twelve months ended December 31, 2011.

Our production volumes for the twelve months ended December 31, 2011 were 434 MBoe, or 1,191 Boe per day. In comparison, our production volumes for the twelve months ended December 31, 2010 were 260 MBoe, or 710 Boe per day. The increase in production volumes was primarily due to ongoing waterflood response to injection, and the drilling programs in our Oklahoma waterflood units in addition to the acquisition of interests in various properties located in the Hugoton Basin area. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the twelve months ended December 31, 2011 was $90.45, compared with $73.92 for the twelve months ended December 31, 2010.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net gain from our commodity hedging program for the twelve months ended December 31, 2011 of approximately $1.3 million, which was composed of a realized loss of $2.2 million and an unrealized gain of $3.4 million. For the twelve months ended December 31, 2010, we recorded a net loss from our commodity hedging program of approximately $0.8 million, which was composed of a realized loss of $0.1 million and an unrealized loss of $0.7 million.

Lease Operating Expenses. Our lease operating expenses were $8.5 million for the twelve months ended December 31, 2011, or $19.56 per Boe, compared to $6.2 million for the twelve months ended December 31, 2010, or $23.99 per Boe. The increase in total lease operating expenses during the twelve months ended December 31, 2011 was primarily attributable to an increase in production resulting from drilling programs, to injection and an increase in the number of wells producing. The decrease in lease operating expenses per Boe was due to the increased production for the twelve months ended December 31, 2011. Ad valorem taxes were also reflected in lease operating expenses. Ad valorem taxes are levied on our properties in Colorado and are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts, and a percentage of production equipment value.

Production Taxes. Our production taxes were $1.9 million for the twelve months ended December 31, 2011, or $4.31 per Boe for an effective tax rate of 4.9%, compared to $0.8 million for the twelve months ended December 31, 2010, or $3.16 per Boe for an effective tax rate of 4.5%. The increase in production taxes during the twelve months ended December 31, 2011 was primarily due to the increase in the realized average oil sales price. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. Although the State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%, a portion of our wells in Oklahoma received a reduced rate due to the Enhanced Recovery Project Gross Production Tax Exemption.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses on producing properties for the twelve months ended December 31, 2011 were $6.8 million, or $15.66 per Boe produced, compared to $5.2 million, or $20.02 per Boe produced, for the twelve months ended December 31, 2010. The increase in depreciation, depletion and amortization expenses on an overall and a decrease on a per Boe produced basis was primarily due to the substantial increase in proved developed reserves estimated at December 31, 2011, in addition to the acquisition of waterflood units in our Hugoton Basin and Southern Oklahoma core areas.

Impairment of Oil and Natural Gas Properties. During the year ended December 31, 2010, we recorded a non-cash impairment charge of $1.9 million due to a decline in reserve estimates for certain producing properties. There was no impairment charge for the year ended December 31, 2011.

General and Administrative Expenses. Our general and administrative expenses were approximately $1.9 million for the twelve months ended December 31, 2011, or $4.43 per Boe produced compared to $1.0 million for the twelve months ended December 31, 2010 or $3.78 per Boe produced. The increase in general and administrative expenses for the twelve months ended December 31, 2011 resulted primarily from higher professional fees of approximately $0.5 million and higher personnel costs of approximately $0.4 million. Professional fees included costs related to the preparation of our registration statement on Form S-1 for our initial public offering and compliance with public reporting requirements, some of which are believed to be non-recurring. Personnel costs were higher due to an increase in employees throughout the organization.

Interest Expense. Our interest expense for the twelve months ended December 31, 2011 was $0.6 million, compared to $0.1 million for the twelve months ended December 31, 2010. The increase was primarily due to increased borrowings on our credit facilities for capital expenditures and acquisitions. In addition, in December 2011, we entered into our current credit facility which resulted in higher average borrowings outstanding.

Year Ended December 31, 2010 Compared to Six Months Ended December 31, 2009

Sales Revenues. Revenues from oil and natural gas sales for the year ended December 31, 2010 were approximately $18.3 million as compared to $6.5 million for the six months ended December 31, 2009. The increase in revenues was primarily due to an increase in oil production and an increase in the average oil and natural gas price during the twelve months ended December 31, 2010.

Our production volumes for the twelve months ended December 31, 2010 were 260 MBoe, or 710 Boe per day. In comparison, our production volumes for the six months ended December 31, 2009 were 110 MBoe, or 602 Boe per day. The increase In addition, in production volumes was primarily due to the drilling programs in our waterflood units and the acquisitions of interests in various properties located in Oklahoma. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the year ended December 31, 2010 was $73.92, compared with $65.85 for the six months ended December 31, 2009.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net loss from our commodity hedging program for the year ended December 31, 2010 of approximately $0.8 million, which is composed of a realized loss of $0.1 million and an unrealized loss of $0.7 million. For the six months ended December 31, 2009, we recorded a net loss from the commodity hedging program of approximately $0.5 million, which is composed of a realized loss of $0.4 million and an unrealized loss of $0.1 million.

Lease Operating Expenses. Our lease operating expenses were $6.2 million for the year ended December 31, 2010, or $23.99 per Boe, compared to $2.4 million for the six months ended December 31, 2009, or $22.10 per Boe. The increase in lease operating expenses, on both a total and per Boe basis, was primarily due to the increase in production and the increase in the number of wells drilled and used for injection during the twelve months ended December 31, 2010. Ad valorem taxes are also reflected in lease operating expenses.

Production Taxes. Our production taxes were $0.8 million for the year ended December 31, 2010, or $3.16 per Boe for an effective tax rate of 4.5%, compared to $0.3 million for the six months ended

December 31, 2009, or $2.45 per Boe for an effective tax rate of 4.2%. The increase in production taxes during the year ended December 31, 2010 was primarily due to the increase in the realized average oil sales price. The increase in the effective tax rate was due to increased production from certain of our Oklahoma properties that do not qualify for reduced tax rates.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses for the year ended December 31, 2010 were $5.2 million, or $20.02 per Boe produced, compared to $2.4 million, or $21.43 per Boe produced, for the six months ended December 31, 2009. The decrease per Boe produced was primarily due to an increase in proved developed reserves during the year ended December 31, 2010.

Impairment of Oil and Natural Gas Properties. An impairment of $1.9 million was required during the year ended December 31, 2010 due to a decline in reserve estimates for certain producing properties. An impairment expense of $9.2 million was also recorded for the six months ended December 31, 2009 due to a decline in reserve estimates for certain producing properties.

General and Administrative Expenses. Our general and administrative expenses were approximately $1.0 million for the year ended December 31, 2010, or $3.78 per Boe produced, compared to $0.7 million of general and administrative expenses for the six months ended December 31, 2009, or $6.40 per Boe produced. The decrease in general and administrative expenses per Boe in the year ended December 31, 2010 was primarily due to increased affiliate subsidiary activity resulting in the subsidiaries receiving a greater allocation of the overall general and administrative expenses.

Interest Expense. Our interest expense for the year ended December 31, 2010 was $98,000 compared to $2,000 for the six months ended December 31, 2009. The increase is attributable to an increase in 2011, we entered into our current credit facility which resulted in higher average borrowings from our credit facilities due to capital expenditures and acquisitions.

Six Months Ended December 31, 2009 Compared to Year Ended June 30, 2009

Sales Revenues. Revenues from oil and natural gas sales for the six months ended December 31, 2009 were approximately $6.5 million as compared to $12.4 million for the twelve months ended June 30, 2009.

Our production volumes for the six months ended December 31, 2009 were 110 MBoe, or 602 Boe per day. In comparison, our production volumes for the year ended June 30, 2009 were 210 MBoe, or 575 Boe per day. The increase in production in Boe per day was due to an increase in oil production partially offset by a decline in natural gas production. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the six months ended December 31, 2009 was $65.85 compared with $66.87 for the year ended June 30, 2009.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net loss from the commodity hedging program for the six months ended December 31, 2009 of approximately $0.5 million, which was composed of a realized loss of $0.4 million and an unrealized loss of $0.1 million. For the year ended June 30, 2009, we recorded realized net gain from the commodity hedging program of approximately $1.0 million, which was composed of $0.7 million of realized loss and an unrealized gain of $1.7 million.

Lease Operating Expenses. Our lease operating expenses were $2.4 million, or $22.10 per Boe produced for the six months ended December 31, 2009 compared to approximately $5.4 million, or $25.56 per Boe produced for the year ended June 30, 2009. The decrease in lease operating expenses per Boe was attributable to an increase in production.

Production Taxes. Our production taxes were $0.3 million for the six months ended December 31, 2009, or $2.45 per Boe for an effective tax rate of 4.2%, compared to $0.6 million for the year ended June 30, 2009, or $3.00 per Boe for an effective tax rate of 5.1%. The decrease in production taxes on a per unit basis during the year ended December 31, 2009 was primarily due to a decrease in the effective tax rate. The decrease in the effective tax rate was due to increased production from certain of our Oklahoma properties that qualify for reduced tax rates.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses for the six months ended December 31, 2009 were $2.4 million, or $21.43 per Boe produced, as compared to $2.1 million, or $10.01 per Boe produced, for the year ended, June 30, 2009. The increase per Boe produced for the six months ended December 31, 2009 was primarily due to a decrease in reserve estimates on a total basis for some of our non-performing properties.

Impairment of Oil and Natural Gas Properties. An impairment of $9.2 million was required during the six months ended December 31, 2009 due to a decline in reserve estimates for certain producing properties. There were no impairment charges for the year ended June 30, 2009.

General and Administrative Expenses. Our general and administrative expenses were approximately $0.7 million for the six months ended December 31, 2009, or $6.40 per Boe produced, compared to $1.8 million of general and administrative expenses for the year ended June 30, 2009 or $8.41 per Boe produced. The decrease in general and administrative expenses per Boe produced was primarily due to an increase in production.

Interest Expense. Our interest expense for the six months ended December 31, 2009 was $2,000 compared to $93,000 for the year ended June 30, 2009. The decrease is attributable to reduced debt resulting from a capital contribution during the six months ended December 31, 2009.

Liquidity and Capital Resources

Prior to our initial public offering, our primary sources of liquidity and capital resources were proceeds from capital contributions from Yorktown, bank borrowings, and cash flow from operations. Our primary uses of capital were for the acquisition, development and drilling of waterflood units.

As a publicly traded partnership, our primary sources of liquidity and capital resources are from cash flow generated by operating activities and borrowings under our credit facility. We also expect to be able to issue additional equity and debt securities from time to time as market conditions allow. Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory, weather and other factors.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to our unitholders and our general partner. In making cash distributions, our general partner will attempt to avoid large variations in the amount we distribute from quarter to quarter. In order to facilitate this, our partnership agreement permits our general partner to establish cash reserves to be used to pay distributions for any one or more of the next four quarters.

In addition, our partnership agreement permits us to borrow funds to make distributions to our unitholders. We may borrow to make distributions to our unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long-term, but short-term factors have caused available cash from operations to be insufficient to sustain our level of distributions. For example, we generally intend to hedge a significant portion of our production. We generally will be required to settle our commodity hedge derivatives within five days of the end of the month. As is typical in the oil and gas industry, we do not generally receive the proceeds from the sale of our hedged production until 20 to 60 days following the end of the month. As a result, when commodity prices increase above the fixed price in the derivative contracts, we will be required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before we receive the proceeds from the sale of the hedged production. If this occurs, we may borrow to fund our distributions.

Cash Flow

Net cash provided by operating activities was approximately $24.1 million, $11.8 million, $10.9 million, $24.4 million, $5.2 million and $1.0 million for the twelve months ended December 31, 2011, December 31, 2010 and June 30, 2009 and for the six months ended June 30, 2012, June 30, 2011, and December 31, 2009, respectively. Our revenues increased significantly for the year ended December 31, 2011 and for the six months ended June 30, 2012 compared to prior periods, primarily due to increased production, favorable commodity pricing, our successful exploitation of our proved reserves, our ability to reduce our per unit operating expenses and our successful acquisition activity and, therefore, our net cash provided by operating activities increased during the same period. Cash provided by operating activities is impacted by the prices received for oil and natural gas and levels of production volumes. Our production volumes in the future will in large part be dependent upon the results of past waterflood development activities and results of future capital expenditures. Our future levels of capital expenditures may vary due to many factors, including development and drilling results, oil and natural gas prices, industry conditions, prices and availability of goods and services and the extent to which proved properties are acquired.

Net cash used in investing activities was approximately $42.0 million, $22.7 million, $12.4 million, $24.0 million, $13.4 million and $5.0 million for the twelve months ended December 31, 2011, December 31, 2010 and June 30, 2009 and for the six months ended June 30, 2012, June 30, 2011 and December 31, 2009, respectively. The increased amount of cash used in investing activities was primarily due to the increased waterflood development activities in Southern Oklahoma, including the in-field drilling in these units, development activity in our Northeastern Oklahoma core area and acquisitions.

Net cash (used in) provided by financing activities was approximately $17.9 million, $10.4 million, $4.8 million, $3.3 million, $8.4 million and ($1.2) million for the twelve months ended December 31, 2011, December 31, 2010 and June 30, 2009 and for the six months ended June 30, 2012, June 30, 2011 and December 31, 2009, respectively. During the six months ended June 30, 2012, we used net borrowings of $13.0 million from our credit facility to finance the purchase of certain oil properties located in our Northeastern Oklahoma core area and certain working interests in our existing units in our Southern Oklahoma core area and paid cash distributions of approximately $9.7 million. For the six months ended June 30, 2011, net cash provided by financing activities was used to acquire the War Party I and II Units in our Hugoton Basin core area. For the six months ended December 31, 2009, net cash provided by financing activities was used to fund a $1.5 million distribution to our members. For the year ended December 31, 2011, we received net proceeds of $87.4 million from our initial public offering, and net proceeds from our financing arrangements of $39.2 million which were used to fund our drilling activity in Southern Oklahoma and the distribution of $110.9 million to redeem the limited liability company membership units held by certain employees, directors, and non-affiliates for the merger of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC into our subsidiary at the closing of our initial public offering. For the year ended December 31, 2010, the cash provided by financing activities primarily related to $10.0 million of capital contributions, $5.3 million from borrowings and was used to fund a $4.8 million distribution to certain members. For the twelve months ended June 30, 2009, the cash provided by financing activities primarily related to $5.0 million of capital contributions.

Working Capital

Our working capital totaled $11.9 million, $2.4 million, $4.4 million, ($1.2) million and $2.4 million at June 30, 2012, December 31, 2011, June 30, 2011, December 31, 2010 and December 31, 2009, respectively. Our cash balances at June 30, 2012, December 31, 2011, June 30, 2011, December 31, 2010 and December 31, 2009 were $4.0 million, $0.2 million, $0.4 million, $0.2 million and $0.8 million, respectively. The negative working capital at December 31, 2010 was directly related to accrued expenses for our drilling program and the accrued unrealized loss on our commodity derivative contracts. In addition, the working capital amount at December 31, 2010 excluded $5.3 million of maturities under our prior credit facilities. These facilities were repaid in full with proceeds from our initial public offering.

Capital Expenditures

We have budgeted a total of $15.6 million capital expenditures for 2012 based on our December 31, 2011 audited reserves and have spent $7.6 million during the six months ending June 30, 2012, which includes $2.4 million for maintenance capital expenditures. Maintenance capital expenditures are capital expenditures that we expect to make on an ongoing basis to maintain our waterflood operations and production over the long-term. Our maintenance capital expenditures are intended to maintain the appropriate injection, reservoir pressure and resulting production response. While our maintenance capital expenditures are focused on maintaining our existing production, they could also create production increases as well. We estimate that maintenance capital expenditures will average approximately $5.0 million per year through the next five years.

Growth capital expenditures are capital expenditures that we expect to make to either develop new waterfloods or add primary production through newly initiated development programs. The primary purpose of growth capital expenditures is to acquire, develop and produce assets that will allow us to increase our production levels and asset base in a manner that is expected to be accretive to our unitholders and, as a result, increase our distributions per unit. Growth capital expenditures on existing properties may include projects such as drilling new injection wells or producing wells on our existing waterflood projects which are at an early stage of development. Growth capital expenditures may also include acquisitions of additional oil and gas properties, including new producing wells that are either in the primary stage of production or in the secondary stage of production but which we believe have upside potential. Although we intend to make acquisitions in the future, including potential acquisitions of producing properties from the Mid-Con Affiliates, we currently have no budgeted growth capital expenditures related to acquisitions, as we cannot be certain that we will be able to identify attractive properties or, if identified, that we will be able to negotiate acceptable purchase contracts.

We generally plan to use cash flow from operations to fund our maintenance capital expenditures. We plan primarily to use external financing sources, including borrowings under our credit facility and the issuance of debt and equity securities, to make growth capital expenditures. Because our proved reserves and production are expected to decline over time, we will need to continue the development of our existing reserves and/or make acquisitions to maintain and grow our distributions to unitholders over time.

If cash flow from operations does not meet our expectations, we may reduce our level of capital expenditures, reduce distributions to our unitholders, and/or fund a portion of our capital expenditures using borrowings under our credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot be certain that budgeted capital will be available on acceptable terms or at all. The covenants in our credit facility could limit our ability to incur additional indebtedness. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to make growth capital expenditures or even fund the capital expenditures necessary to maintain our production or proved reserves.

The amount and timing of our capital expenditures are largely discretionary and within our control. If oil and natural gas prices decline below levels we deem acceptable, we may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside of our control that could affect the timing of our expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews. Based on our current oil and natural gas price expectations, we anticipate that our cash flow from operations and available borrowing capacity under our credit facility will exceed our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2012. However, future cash flow is subject to a number of variables, including the level of our oil and natural gas production and the prices we receive for our oil and natural gas production. We cannot be certain that our operations and other capital resources will provide cash in amounts that are sufficient to maintain our planned levels of capital expenditures.

Credit Facility

Our wholly owned subsidiary, Mid-Con Energy Properties, as borrower, and we, as guarantor, have a $250.0 million senior secured revolving credit facility that expires in December 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiary. 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 partners. The facility requires the maintenance of a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (each as defined in the credit agreement) of not more than 4.0 to 1.0, and a current ratio of not less than 1.0 to 1.0. As of June 30, 2012, we were in compliance with all of the facility s financial covenants.

Borrowings under the facility may not exceed our current borrowing base of $100.0 million. The borrowing base is determined by the lenders based on our oil and natural gas reserves. The borrowing base is subject to scheduled redeterminations on or about April 30 and October 31 of each year with an optional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. An optional 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. The borrowing base is 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.

Additionally, borrowings under the facility will bear interest, at Mid-Con Energy Properties option, at either (i) the greater of the prime rate of the Royal Bank of Canada, the federal funds effective rate plus 0.50%, and the one month adjusted London Inter-Bank Offered Rate (LIBOR) plus 1.0% , all of which is subject to a margin that varies from 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. 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. At June 30, 2012, we had $58.0 million of borrowings outstanding under our credit facility.

We continue to monitor our liquidity and the credit markets. Additionally, we continue to monitor events and circumstances surrounding each of the lenders in our credit facility. As of June 30, 2012, our $250.0 million senior secured credit facility had borrowing capacity of $42.0 million ($100.0 million borrowing base less $58.0 million of outstanding borrowings under our credit facility). On April 23, 2012, the borrowing base of our credit facility increased from $75.0 million to $100.0 million, and on September 20, 2012 the borrowing base was reaffirmed by our lenders at $100.0 million.

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Derivative Contracts

For the three months ending December 31, 2012 and years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our audit of proved reserves as of December 31, 2011).

The following table summarizes, for the periods indicated, our oil swaps and put/call options, or collars, through December 31, 2014. These transactions are settled based upon the NYMEX-WTI price of oil.

Term	Type of Derivative	Weighted Average ($/Bbl)	Bbls/d
2012	Swaps	$ 101.85	1,207
2012	Put/Call (Collars)	$ 100 $117	196
2013	Swaps	$ 100.14	1,216
2013	Put/Call (Collars)	$ 97.67 108.08	296
2014	Swaps	$ 94.30	1,315

Our hedging strategy is to enter into various commodity derivative contracts intended to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program s objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distributions over time, while retaining some ability to participate in upward movements in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher hedged percentage in the near 12 months of the period. For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our reserve audit of proved reserves as of December 31, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, respectively.

The following table details, for the periods indicated, our oil swaps and collars, through December 31, 2014. These transactions are settled based upon the NYMEX-WTI price of oil.

Months Outstanding	Settlement Price	Floor	Ceiling	Instrument Type	Total Bbls. Per Month	NYMEX Index
Oct-Dec 2012		$ 100.00	$ 117.00	Collar	6,000	WTI
Oct-Dec 2012	$ 104.28			Swap	6,000	WTI
Oct-Dec 2012	$ 100.00			Swap	8,000	WTI
Oct-Dec 2012	$ 100.97			Swap	10,000	WTI
Oct-Dec 2012	$ 99.95			Swap	5,000	WTI
Oct-Dec 2012	$ 101.40			Swap	5,000	WTI
Oct-Dec 2012	$ 108.80			Swap	3,000	WTI

Months Outstanding	Settlement Price	Floor	Ceiling	Instrument Type	Total Bbls. Per Month	NYMEX Index
Jan-Dec 2013		$ 100.00	$ 111.00	Collar	6,000	WTI
Jan-Dec 2013	$ 105.80			Swap	6,000	WTI
Jan-Dec 2013	$ 96.00			Swap	8,000	WTI
Jan-Dec 2013	$ 97.70			Swap	5,000	WTI
Jan-Dec 2013	$ 99.05			Swap	5,000	WTI
Jan-Dec 2013	$ 100.05			Swap	5,000	WTI
Jan-Dec 2013	$ 104.70			Swap	5,000	WTI
Jan-Dec 2013	$ 98.30			Swap	3,000	WTI
Jan-Dec 2013		$ 93.00	$ 102.25	Collar	3,000	WTI
Jan-Dec 2014	$ 96.10			Swap	5,000	WTI
Jan-Dec 2014	$ 100.00			Swap	5,000	WTI
Jan-Dec 2014	$ 97.40			Swap	5,000	WTI
Jan-Dec 2014	$ 97.96			Swap	5,000	WTI
Jan-Dec 2014	$ 89.50			Swap	5,000	WTI
Jan-Dec 2014	$ 89.35			Swap	5,000	WTI
Jan-Dec 2014	$ 89.87			Swap	5,000	WTI
Jan-Dec 2014	$ 94.25			Swap	5,000	WTI

Contractual Obligations

A summary of our contractual obligations as of June 30, 2012 is provided in the following table.

	Obligations Due in Period (in thousands)					
Contractual Obligation	2012	2013	2014	2015	Thereafter	Total
Long-term debt	$	$	$	$	$ 58,000	$ 58,000
Interest on long-term debt(1)	725	1,450	1,450	1,450	1,406	6,481
Total contractual obligations	$ 725	$ 1,450	$ 1,450	$ 1,450	$ 59,406	$ 64,481

(1) Based upon an average interest rate of approximately 2.5% under the credit facility at June 30, 2012.

Quantitative and Qualitative Disclosure about Market Risk

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

Commodity Price Risk

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

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

Swaps

In a typical commodity swap agreement, we receive the difference between a fixed price per unit of production and a price based on an agreed upon published third-party index, if the index price is lower than the fixed price. If the index price is higher than the fixed price, we pay the difference. By entering into swap agreements, we effectively fix the price that we will receive in the future for the hedged production. Our swaps are settled in cash on a monthly basis.

For a summary of the oil swaps and swap prices, related basis swap prices and resulting adjusted swap prices in place as of June 30, 2012, please read Liquidity and Capital Resources Derivative Contracts.

Put/Call Options

A combination of a put option we purchase and a call option we sell is often referred to as a put/call or a collar. In a typical collar transaction, if the reference price, based on NYMEX quoted prices, is below the floor price, we receive an amount equal to this difference multiplied by the specified volume. If the reference price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the reference price exceeds the ceiling price, we must pay an amount equal to this difference multiplied by the specified volume.

For a summary of the oil collars in place as of June 30, 2012, please read Liquidity and Capital Resources Derivative Contracts.

Interest Rate Risk

At June 30, 2012, we had $58.0 million of debt outstanding under our credit facility, with an effective interest rate of approximately 2.5%. 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 $145,000 on an annual basis. Our credit facility allows us to borrow up to $100.0 million, at an interest rate ranging from LIBOR plus 1.75% to LIBOR plus 2.75% or the prime rate plus 0.75% to the prime rate plus 1.75% depending on the amount borrowed. The prime rate is the United States prime rate as announced from time-to-time by the Royal Bank of Canada.

Counterparty and Customer Credit Risk

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

We are also subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our 2012 production. The inability or failure of any of our customers to meet its obligations to us or its insolvency or liquidation may adversely affect our financial results. However, Sunoco Logistics, Enterprise, Coffeyville Resources and Vitol each have positive payment histories, and Sunoco Logistics and Enterprise each have investment grade credit ratings and Coffeyville Resources is rated one level below investment grade. Accordingly, we believe that the credit quality of such customers is high.

Critical Accounting Policies and Estimates

Oil and Natural Gas Quantities

Our estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrated, 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, 2011 included in this prospectus are based on a reserve report prepared by our reservoir engineering staff and audited by Cawley, Gillespie & Associates, Inc. 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.

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 reserved 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 natural gas liquids eventually recovered.

Successful Efforts Method of Accounting

We account for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively.

We evaluate the impairment of our proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. 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 flow is the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation and depletion unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

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Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as costs related to proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. We will assess unproved properties for impairment quarterly on the basis of our experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved 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 unproved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors.

Impairment of Oil and Natural Gas Properties

For the year ended December 31, 2010 we recorded a non-cash impairment charge of approximately $1.9 million, primarily associated with proved oil and natural gas properties related to unfavorable market conditions. For the year ended December 31, 2010, approximately $0.6 million of the impairment charge was associated with properties that were sold to the Mid-Con Affiliates. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair-value measurement. The charges are included in impairment of oil and natural gas properties in our combined statement of operations. We recorded no impairment charge for proved oil and natural gas properties for the year ended December 31, 2011 or for the six months ended June 30, 2012.

Asset Retirement Obligations

The initial estimated asset retirement obligation associated with oil and natural gas properties is recognized as a liability, with a corresponding increase in the carrying value of oil and natural gas properties. Amortization expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the liability and the carrying value of the property. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations.

Revenue Recognition

Oil and natural gas revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable.

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.

Our derivative contracts are exchange-traded transactions. Valuation is determined by reference to readily available public data.

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We recognize all of our derivative contracts as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative contract depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative contracts that are designated and qualify as hedging instruments, we designated the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative contracts not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of our derivatives were designated as hedging instruments during the year ended December 31, 2011, the six months ended June 30, 2011, or the six months ended June 30, 2012, respectively.

Recently Issued Accounting Pronouncements

No new accounting pronouncements issued or effective during the six months ended June 30, 2012 have had or are expected to have a material impact on our consolidated financial statements.

Internal Controls and Procedures

Because we are a publicly traded partnership, we are required to comply with the SEC s rules implementing Sections 302 and 404 of the Sarbanes-Oxley Act of 2002, which require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal controls over financial reporting. Though we will be required to disclose changes made to our internal controls and procedures on a quarterly basis, we are not required to make our first annual assessment of our internal controls over financial reporting pursuant to Section 404 until 2013.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2009, 2010 and 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the U.S. economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment, as increasing oil prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

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BUSINESS AND PROPERTIES

Overview

We are a Delaware limited partnership formed in July 2011 to own, operate, acquire, exploit and develop producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. 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. Through the continued development of our existing properties and through future acquisitions, we will seek to increase our reserves and production in order to maintain 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 significant portion of our production volumes through various commodity derivative contracts.

As of December 31, 2011, our total estimated proved reserves were 10.0 MMBoe, of which approximately 99% were oil and approximately 69% were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating operated 99% of our properties and 96% were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended June 30, 2012 was approximately 1,844 Boe per day and based on our December 31, 2011 audited reserves, as adjusted for average net production for the six months ended June 30, 2012, our estimated proved reserves had a reserve-to-production ratio of approximately 15 years. As of December 31, 2011, our management team developed approximately 59% of our total reserves through new waterflood projects.

Our properties are located in the Mid-Continent region of the United States and primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates. Our core areas of operation are located in Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. As of December 31, 2011, approximately 91% of the properties associated with our estimated reserves, on a Boe basis, have been producing continuously since 1982 or earlier. Through the application of waterflooding, we believe these mature properties have attractive upside potential. Waterflooding, a form of secondary oil recovery, works by repressuring a reservoir through water injection and pushing or sweeping oil to producing wellbores. Based on the production estimates from our December 31, 2011 audited reserves, the average estimated decline rate for our proved developed producing reserves is approximately 8.0% for 2012 and, on a compounded average decline basis, approximately 11% for the subsequent five years and approximately 10% thereafter.

The following table summarizes information by core area regarding our estimated oil and natural gas reserves as of December 31, 2011 and our average net production for the month ended June 30, 2012.

	Estimated Net Proved Reserves as of December 31, 2011				Average Net Production for the Month Ended June 30, 2012			Gross Active Wells as of June 30, 2012		
	(MBoe)	% Operated(1)	% Oil	% Proved Developed	Boe/d Gross	Boe/d Net	Reserve-to-Production Ratio(2)	Oil and Natural Gas Wells	Injection Wells	Shut-in/ Waiting on Completion
Southern Oklahoma	5,528	100%	100%	68%	2,600	1,128	13	79	53	12
Northeastern Oklahoma	3,179	100%	99%	69%	742	447	19	201	76	54
Hugoton Basin	1,060	100%	99%	69%	340	219	13	29	15	13
Other	282	77%	77%	100%	140	50	15	11	5	2
Total	**10,049**	**99%**	**99%**	**69%**	**3,822**	**1,844**	**15**	**320**	**149**	**81**

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(2) The reserve-to-production ratio is calculated by subtracting production for the six months ended June 30, 2012 from estimated net proved reserves as of December 31, 2011 and dividing the result by average net production for the month ended June 30, 2012.

The following chart summarizes our total average net Boe production volumes on a monthly basis, and illustrates the 47% increase in our production volumes over the twelve months ended June 30, 2012. We achieved this production increase primarily through ongoing waterflood response from existing development activities and from workovers and acquisitions.

Recent Developments

On October 15, 2012, we entered into a Purchase and Sale Agreement to acquire certain oil properties located in our Hugoton Basin core area. The base purchase price for such properties, which is subject to standard adjustments and preference right exercises, is approximately $21 million, which includes a performance deposit of $2.1 million. This acquisition is expected to close on or before November 6, 2012 and will be financed using existing cash and borrowings from our credit facility. This acquisition includes current net production of approximately 175 Boe per day, estimated net proved reserves of approximately 1.3 MMBoe (55% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. We will acquire 14 gross producing, 7 gross injecting and 1 gross water supply well associated with these properties. The estimated proved reserves for this acquisition were based on our preliminary internal evaluation of information provided by the seller and proved reserves as of the acquisition date for the above-referenced acquisition were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that this acquisition will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Additionally, on October 12, 2012, we entered into an agreement to assign additional working interests in our existing War Party I and II Units located in our Hugoton Basin core area, effective as of April 1, 2012. Pursuant to this agreement, we will pay approximately $3.5 million for these properties using existing cash and borrowings from our credit facility. As a result of this assignment, we will have 100% and 99% of the working interests in our War Party I and II Units, respectively. The working interests to be assigned include current net production of approximately 83 Boe per day, estimated net proved reserves of approximately 0.5 MMBoe (85% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. The estimated proved reserves for the working interests to be assigned are based on our preliminary internal evaluation of information provided by the seller, and proved reserves as of the effective date for the above-referenced assignment is estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that the working interests included in this assignment will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Completion of these acquisitions are subject to the satisfaction of customary closing conditions and the waiver of preference rights and obtaining necessary consents from third parties. Failure to satisfy these conditions, if not waived, would prevent us from consummating these acquisitions or the amount of properties we may obtain may be materially reduced, resulting in a proportional decrease in our expected net reserves and production. As a result, we can provide no assurance that these acquisitions will be completed within the anticipated time frame, or at all. The closing of these acquisitions is not conditioned on the closing of this offering, and this offering is not conditioned on the closing of these acquisitions. In the event that we are unable to complete these acquisitions, our approximately $2.1 million deposit we have paid for the Clawson Ranch would potentially be subject to forfeiture.

During June 2012, we acquired certain oil properties located in our Northeastern Oklahoma core area, and additional working interests in our existing units in our Southern Oklahoma core area, in unrelated transactions. We paid approximately $16.4 million in aggregate consideration for these properties. The transactions were financed using existing cash and borrowings from our credit facility. These acquisitions include current net production of approximately 115 Boe per day, estimated net proved reserves of approximately 0.6 MMBoe (53% proved developed producing and 100% oil on a Boe basis) and an average reserve-to-production ratio of approximately 14 years. The estimated proved reserves for these acquisitions were based on our preliminary internal evaluation of information provided by the sellers and proved reserves as of the acquisition date for the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that these acquisitions were immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for these properties may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

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Our general partner also declared a cash distribution of $0.485 per unit ($1.94 per unit on an annualized basis) on October 15, 2012 for the third quarter of 2012, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 7, 2012. This is an increase of $0.01 from the previous quarter. Our management also confirmed on October 15, 2012 that our previously released Boe production guidance for the third quarter of 2012 will come in within the previously announced range, likely toward the lower-end.

Our Hedging Strategy

Our hedging strategy is to enter into various commodity derivative contracts intended to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program s objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distributions over time, while retaining some ability to participate in upward moves in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher amount of hedges in the near 12 months. For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our audit of proved reserves as of December 31, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, respectively.

By removing a significant 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 flow from operations for those periods. For a further description of our commodity derivative contracts, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Derivative Contracts.

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 at the current quarterly distribution rate and, over time, to increase our quarterly cash distributions. In addition to our hedging strategy described above, 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. Using these techniques, we significantly increased our average net production over the twelve months ended December 31, 2011. We expect to continue these activities in order to maximize our production.

- ***Pursue acquisitions of long-lived, low-risk producing properties with upside potential.*** We will seek to acquire onshore 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, production and cash flow.

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Capitalize on our relationship with the Mid-Con Affiliates for favorable acquisition opportunities. We expect that the Mid-Con Affiliates will 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 the Mid-Con Affiliates, 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 them, we expect that the Mid-Con Affiliates will offer to sell properties to us from time to time. We believe that the opportunity to acquire properties from the Mid-Con Affiliates 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, 2011, Mid-Con Energy Operating operated 99% of our properties, as 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 flow through a disciplined commodity hedging strategy. We will seek to reduce the impact of commodity price volatility on our cash flow by maintaining a portfolio of hedge contracts to help protect our ability to make distributions. As opposed to entering into commodity derivative contracts at predetermined times or on prescribed terms, we intend to enter into 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. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes or the duration of our hedge contracts when circumstances suggest that it is prudent to do so.

Maintain a balanced capital structure to allow for financial flexibility to execute our business strategies. We intend to maintain a balanced capital structure that will afford us the financial flexibility to execute our business strategies. We believe our borrowing capacity under our credit facility, our access to capital markets and internally generated cash flow will provide us with the liquidity and financial flexibility to exploit organic growth opportunities and allow us to pursue additional acquisitions of producing properties.

Utilize compensation programs that align the interests 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 award and long-term, equity-based incentive grants. The amount of the annual short-term incentive award 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 the 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.

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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 99% 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 and Colorado 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 flow. Over 96% of our properties are being waterflooded and over 91% have been producing continuously since 1982 or earlier. Based on production estimates from our December 31, 2011 audited reserves, the average estimated decline rate for our existing proved developed producing reserves is approximately 8% for 2012 and, on a compounded average decline basis, approximately 11% for the subsequent five years and approximately 10% thereafter. Further, we believe that a substantial majority of the capital required for growth from our existing properties has been spent prior to this offering. 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. Our management team has actively operated most of our properties since 2005, and has a history of exploiting proved reserves to maximize production, primarily through waterflood projects. Over the last seven years, we identified, initiated, acquired, formed and developed over 27% of all new waterflood projects in the State of Oklahoma, while the next most active competitor formed only 6% 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 across the region. We believe that our expertise in secondary recovery techniques will increase the level of production from certain of our properties, particularly from existing waterflood projects, which, over time, may increase our cash flow.

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 Affiliates. We expect the Mid-Con Affiliates to invest capital and technical staff resources to acquire and develop properties with existing projects and to identify, acquire, form and develop new waterflood projects on their properties. While they are not obligated to sell any properties to us and may have difficulties acquiring and developing them, we expect that the Mid-Con Affiliates will offer to sell properties to us from time to time. Through this relationship with the Mid-Con Affiliates, 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.

Access to the collective expertise of Yorktown s employees and their extensive network of industry relationships through our relationship with Yorktown. Yorktown is a private investment firm focused on investments in the energy sector with more than $3.0 billion in assets under management. Prior to this offering, Yorktown owned an approximate 48.5% limited partner interest in us, making it our largest unitholder. Following this offering, Yorktown will own an approximate 30.1% limited partner interest in us (or an approximate 26.9% limited partner interest in us if the underwriters exercise in full their option to purchase additional common units) and will continue to be our largest unitholder. Yorktown Energy Partners IX, L.P. will continue to own a 50% interest in our affiliate, Mid-Con Energy Operating. With their extensive investment experience in the oil and natural gas industry and their extensive network of industry relationships, we believe that 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 99% of our properties, which allows them to control our operating costs and capital expenditures. As of December 31, 2011, Mid-Con Energy Operating operated 99% 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. We believe that this substantial operational control of our producing properties also allows us to maximize the value of our properties, helps us stabilize our cash flow and affords us better control over the timing and costs of our operations.

An enhanced ability to pursue acquisition opportunities arising from our competitive cost of capital and balanced capital structure. Unlike our corporate competitors, we are not subject to federal income taxation at the entity level. This attribute should provide us with a lower cost of capital compared to those competitors, thereby enhancing our ability to compete for future acquisitions of oil and, when advantageous, natural gas properties. We also believe our low level of indebtedness and our ability to issue additional common units and other partnership interests in connection with these acquisitions will improve our financial flexibility. Further, we have an available borrowing capacity of approximately $42.0 million under our credit facility after giving effect to approximately $58.0 million previously borrowed thereunder, which provides us with another potential means of financing acquisition opportunities.

The range and depth of our technical and operational expertise will allow us to expand both geographically and operationally to achieve our goals. During the past nine years, 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 150 waterflood projects located in more than ten states. We have a team of more than 65 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, we believe that 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 region, our management and operational employees have significant oil and gas experience in many other regions of the United States. We believe that our wealth of experience may enable 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.

Our Principal Business Relationships

Our Relationship with the Mid-Con Affiliates

In June 2011, management and Yorktown formed two limited liability companies, which we refer to as the Mid-Con Affiliates, to acquire and develop 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 certain of

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these properties from the Mid-Con Affiliates. Through this relationship with the Mid-Con Affiliates, 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. However, the Mid-Con Affiliates may not be successful in identifying or consummating acquisitions or in successfully developing the new properties they acquire. Further, the Mid-Con Affiliates are not obligated to sell any properties to us and they are not prohibited from competing with us to acquire oil and natural gas properties. For a summary of the process by which such mutually agreeable prices will be determined, please read Certain Relationships and Related Party Transactions Review, Approval or Ratification of Transactions with Related Persons.

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. Yorktown made several equity investments in our predecessor. Prior to this offering, Yorktown owned an approximate 48.5% limited partner interest in us, making it our largest unitholder. Following this offering, Yorktown will own an approximate 30.1% limited partner interest in us (or an approximate 26.9% limited partner interest in us if the underwriters exercise their option to purchase additional common units), and will continue to be our largest unitholder. Yorktown Energy Partners IX, L.P. will continue to own a 50% interest in our affiliate, Mid-Con Energy Operating. Also, Peter A. Leidel, a principal of Yorktown, serves on our board of directors.

Yorktown currently has more than $3.0 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, we believe that 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 the Mid-Con Affiliates, that are engaged in the oil and natural gas industry and, as a result, Yorktown may present acquisition opportunities to other Yorktown portfolio companies, including the Mid-Con Affiliates, that compete with us.

Oil Recovery Overview

When an oil field is first produced, the oil typically is recovered as a result of expansion of reservoir fluids which are naturally pressured within the producing formation. The only natural force present to move the oil through the reservoir rock to the wellbore is the pressure differential between the higher pressure in the rock formation and the lower pressure in the producing wellbore. Various types of pumps are often used to reduce pressure in the wellbore, thereby increasing the pressure differential. At the same time, there are many factors that act to impede the flow of oil, depending on the nature of the formation and fluid properties, such as pressure, permeability, viscosity and water saturation. This stage of production, referred to as primary recovery, recovers only a small fraction of the oil originally in place in a producing formation, typically ranging from 10% to 25%.

After the primary recovery phase many, but not all, oil fields respond positively to secondary recovery techniques in which external fluids are injected into a reservoir to increase reservoir pressure and to displace oil towards the wellbore. Secondary recovery techniques often result in increases in production and reserves above primary recovery. Waterflooding, a form of secondary recovery, works by repressuring a reservoir through water injection and sweeping or pushing oil to producing wellbores. Conventional hydraulic fracturing techniques are often employed to increase a well s productivity in waterflooding.

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Through waterflooding, water injection replaces the loss of reservoir pressure caused by the primary production of oil and gas, which is often referred to as pressure depletion or reservoir voidage. As a result of the water used in a waterflood, produced fluids contain both water and oil, with the relative amount of water increasing over time. Surface equipment is used to separate the oil from the water, with the oil going to pipelines or holding tanks for sale and the water being recycled to the injection facilities. In general, in the Mid-Continent region, a secondary recovery project may produce an additional 10% to 20% of the oil originally in place in a reservoir.

A third stage of oil recovery is called tertiary recovery. In addition to maintaining reservoir pressure, this type of recovery seeks to alter the properties of the oil in ways that facilitate additional production. The three major types of tertiary recovery are chemical flooding, thermal recovery (such as a steamflood) and miscible displacement involving carbon dioxide (CO_2), hydrocarbon or nitrogen injection. We are currently field testing new technologies in chemical flooding on some of our properties. If successful, this testing may lead to reserve and production increases in the future. Any future tertiary development programs and subsequent capital expenditures would be contingent upon commercial viability established by successful pilot testing. At this time, there are no estimated reserves or production associated with tertiary recovery projects assigned to our properties. We will continue to review future opportunities for growth through the use of various tertiary recovery techniques.

Our Properties

Our properties are located in the Mid-Continent region of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. These core areas are each composed of multiple units that are in close proximity to one another, produce from the same or geologically similar reservoirs and use similar waterflood methods. Focusing on these core areas allow 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 read Summary of Oil Properties and Projects.

Our properties consist of mature, legacy onshore oil reservoirs, approximately 96% of the reserves of which are being produced under waterflood on a Boe basis. Our properties include multiple waterflood projects with varying degrees of maturity. We have staggered the waterflooding of these properties so that production increases from more recently developed waterfloods offsets declines from mature waterflood areas, leading to more stable cash flow and production.

We use words such as mature or legacy to describe our properties as having established operating, reservoir and production characteristics. The production and corresponding decline rates attributable to properties of this type in contrast with more recently drilled properties can generally be forecast with a greater degree of accuracy. Our ability to predict future performance is further enhanced by the familiarity that we have with most of our properties. We have observed the performance of many of our properties over many years, in many cases from the inception of waterflooding. This long-term observation allows for greater understanding of production and reservoir characteristics, making future performance more predictable.

As of June 30, 2012, we owned a 68% average working interest across 320 gross producing (224 net) wells, 149 gross injection (97 net) wells, and 81 gross (67 net) wells shut-in or waiting on completion. Mid-Con Energy Operating operates 99% of our properties by value, as calculated using the standardized measure. Approximately 97% of our revenue is derived from the proceeds of oil production. Based on the standardized measure, our value-weighted average working interest on these properties was approximately 68% based on our December 31, 2011 audited reserves. Our estimated proved reserves as of December 31, 2011 were 10.0 MMBoe, of which approximately 99% were oil and approximately 69% were

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proved developed, both on a Boe basis. Based on production estimates from our December 31, 2011 audited reserves, the average estimated decline rate for our existing proved developed producing reserves is approximately 8.0% for 2012, approximately 11% for the subsequent five years and, on a compounded average decline basis, approximately 10% thereafter.

The following table shows estimated net proved oil reserves or principal fields, 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, 2011, 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 June 30 2012		Estimated Net Proved Reserves as of December 31, 2011(3)						
	Net (Boe/d)	% of Total	MBoe	% of Total Proved Reserves	% Oil	% Proved Developed Reserves	Undiscounted Cap. Ex. (in millions)	Standardized Measure(2)(3) (in millions)	% of Total
Southern Oklahoma Fields/Units:									
Highlands(1)	412	22%	2,621	26%	100%	78%	$ 9	$ 110	34%
Battle Springs(1)	330	18%	1,144	11%	100%	79%	$ 4	$ 50	15%
Twin Forks (1)	308	17%	851	9%	100%	72%	$ 3	$ 34	10%
Ardmore West(1)	26	1%	750	8%	100%	2%	$ 3	$ 25	8%
Southeast Hewitt	37	2%	137	1%	100%	100%	$ 0	$ 5	2%
Other Fields/Units	15	<1%	25	0%	78%	100%	$ 0	$ 1	0%
Total Southern Oklahoma	**1,128**	**60%**	**5,528**	**55%**	**100%**	**68%**	**$ 19**	**$ 225**	**69%**
Northeastern Oklahoma Fields / Units:									
Cleveland	299	16%	1,959	20%	99%	66%	$ 3	$ 45	14%
Cushing	101	5%	765	8%	98%	82%	$ 2	$ 17	5%
Skiatook(1)	36	2%	426	4%	100%	58%	$ 1	$ 8	2%
Other Fields/Units	11	1%	29	0%	98%	100%	$ 0	$ 1	0%
Total Northeastern Oklahoma	**447**	**24%**	**3,179**	**32%**	**99%**	**69%**	**$ 6**	**$ 71**	**21%**
Hugoton Fields / Units:									
War Party I(1)	70	4%	232	2%	100%	84%	$ 2	$ 3	1%
War Party II(1)	90	5%	510	5%	99%	75%	$ 1	$ 10	3%
Harker Ranch(1)	59	3%	318	3%	100%	47%	$ 3	$ 10	3%
Total Hugoton	**219**	**12%**	**1,060**	**10%**	**99%**	**69%**	**$ 6**	**$ 23**	**7%**
Other Fields / Units:									
Decker(1)	19	1%	216	2%	100%	100%	$ 0	$ 7	2%
Miscellaneous	31	3%	66	1%	0%	100%	$ 0	$ 2	1%
Total Other	**50**	**4%**	**282**	**3%**	**77%**	**100%**	**$ 0**	**$ 9**	**3%**
All Fields	**1,844**	**100%**	**10,049**	**100%**	**99%**	**69%**	**$ 31**	**$ 328**	**100%**

(1) Denotes a waterflood project or unit that we identified, acquired, formed and developed.

(2) Standardized measure is calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 932, *Extractive Activities Oil and Gas*. 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. For a

description of our commodity derivative contracts, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Derivative Contracts.

(3) 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 $96.19 per Bbl for oil and $4.11 per MMBtu for natural gas for the 12 months ended December 31, 2011.

Summary of Oil Properties and Projects

Our principal fields detailed below represent approximately 99% of our total estimated net proved reserves as of December 31, 2011, 96% of our average daily net production for the month ended June 30, 2012 and 99% of our standardized measure as of December 31, 2011. Please read Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations in evaluating the material presented below. 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, 2011 audited reserves and production and well status for the month ending June 30, 2012.

Southern Oklahoma

Highlands Unit. The Highlands Unit is in the SE Joiner City Field, an oil-weighted field located in Love County, Oklahoma. Since its discovery in 1980, the Highlands Unit has produced approximately 3,247 MBoe. Production from the Highlands Unit is from the Deese formation at an average depth of approximately 8,000 feet. The Highlands Unit was formed and is operated by our affiliate, Mid-Con Energy Operating and is being produced under waterflood. Injection began during October 2008, and production response to injection started in April 2009. We own 27 gross (19 net) producing, 23 gross (17 net) injection and 2 gross (1 net) recently drilled but not completed wells in this unit with an average working interest of 72%. As of June 30, 2012, our properties in this unit were producing 878 Boe per day gross, 412 Boe per day net. As of December 31, 2011, the Highlands Unit contained 2,621 MBoe of estimated net proved reserves.

Battle Springs Unit. The Battle Springs Unit is in the SE Joiner City Field, an oil-weighted field located in Love County, Oklahoma. Since its discovery in 1982, the Battle Springs Unit has produced approximately 2,928 MBoe. Production from the Battle Springs Unit is from the Deese formation at an average depth of approximately 8,850 feet. The Battle Springs Unit was formed and is operated by our affiliate, Mid-Con Energy Operating and is being produced under waterflood. Injection began during September 2006, and production response to injection started in December 2006. We own 25 gross (13 net) producing and 15 gross injection (8 net) wells in this unit with an average working interest of 51%. As of June 30, 2012, our properties in this unit were producing 818 Boe per day gross, 330 Boe per day net. As of December 31, 2011, the Battle Springs Unit contained 1,144 MBoe of estimated net proved reserves.

Twin Forks Unit. The Twin Forks Unit is in the SE Joiner City Field, an oil-weighted field located in Carter County, Oklahoma. Since its discovery in 1979, the Twin Forks Unit has produced approximately 1,223 MBoe. Production from the Twin Forks Unit is from the Deese formation at an average depth of approximately 7,000 feet. The Twin Forks Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during September 2009, and production response to injection started in October 2010. We own 7 gross (4 net) producing and 5 gross (3 net) injection wells in this unit with an average working interest of 64%. As of June 30, 2012, our properties in this unit were producing 605 Boe per day gross, 308 Boe per day net. As of December 31, 2011, the Twin Forks Unit contained 851 MBoe of estimated net proved reserves.

Ardmore West Unit. The Ardmore West Unit is in the Ardmore West Field, an oil-weighted field located in Carter County, Oklahoma. Since its discovery in 1969, the Ardmore West Unit has produced approximately 711 MBoe. Production from the Ardmore West Unit is from the Deese formation at an average depth of approximately 7,000 feet. The Ardmore West Unit is a waterflood currently being developed which was formed in July 2010 and is operated by our affiliate, Mid-Con Energy Operating. Injection began during September 2011. We own 4 gross (4 net) producing and 3 gross (3 net) injection wells in this unit with an average working interest of 96%. As of June 30, 2012, our properties in this unit were producing 34 Boe per day gross, 26 Boe per day net. As of December 31, 2011, the Ardmore West Unit contained 750 MBoe of estimated net proved reserves.

Southeast Hewitt Unit. The Southeast Hewitt Unit is in the SE Wilson Field, an oil-weighted field located in Carter County, Oklahoma. Since its discovery in 1979, the Southeast Hewitt Unit has produced approximately 1,663 MBoe. Production from the Southeast Hewitt Unit is from the Deese formation at an average depth of approximately 6,000 feet. The Southeast Hewitt Unit is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during June 1997, and production response to injection started in November 1997. Mid-Con Energy I, LLC acquired a working interest in the SE Hewitt Unit in November 2004, and Mid-Con Energy Operating became the operator of the unit in May 2010. We own 10 gross (2 net) producing and 6 gross (1 net) injection wells in this unit with an average working interest of 24%. As of June 30, 2012, our properties in this unit were producing 217 Boe per day gross, 37 Boe per day net. As of December 31, 2011, the Southeast Hewitt Unit contained 137 MBoe of estimated net proved reserves.

Northeastern Oklahoma

Cleveland Field. The Cleveland Field is an oil-weighted field located in Pawnee County, Oklahoma. Since its discovery in 1904, the entire Cleveland Field has produced approximately 47 MMBoe. Production from the Cleveland Field is primarily from the multiple Pennsylvanian age sands at depths from 1,000 to 2,400 feet. Waterflooding in the Cleveland Field was initiated in most areas by about 1960, although waterflood pilot testing began on some leases prior to 1960. Approximately 1,880 gross acres in the Cleveland Field is being operated by our affiliate, Mid-Con Energy Operating. Approximately 1,000 of the total 1,880 gross acres have been acquired in the last four years. We have been actively developing our Cleveland Field leases through drilling, recompletions and workovers, resulting in a significant increase in net production within the last two years. The majority of Mid-Con Energy Operating operated leases are produced under waterflood. Mid-Con Energy Operating operates 108 gross (105 net) producing wells, 27 gross (26 net) injection wells and 2 gross (2 net) recently drilled but not completed wells in this field with an average working interest of 97%. As of June 30, 2012, our properties in this field were producing 357 Boe per day gross, 299 Boe per day net. As of December 31, 2011, our leases within the Cleveland Field contained 1,959 MBoe of estimated net proved reserves.

Cushing Field. The Cushing Field, one of the largest oil fields (by total historical production volume) in the United States is an oil-weighted field located in Creek County, Oklahoma. Since its discovery in 1912, the entire Cushing Field has produced in excess of 500 MMBoe, with our leases having produced approximately 9,575 MBoe. Production from the Cushing Field is primarily from multiple Pennsylvanian age sands at depths from 1,200 to 2,500 feet. Waterflooding in the Cushing field was initiated in some areas by about 1955, although waterflood pilot testing began on some leases as early as 1949. Our affiliate, Mid-Con Energy Operating, operates approximately 3,360 acres in the Cushing Field, the majority of which are being produced under waterflood. We are currently engaged in a drilling program on this property to

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develop additional reserves. We operate 75 gross (29 net) producing, 39 gross (14 net) injection and 2 gross (1 net) recently drilled but not completed wells in this field with an average working interest of 37%. As of June 30, 2012, our properties in this field were producing 320 Boe per day gross, 101 Boe per day net. As of December 31, 2011, our leases within the Cushing Field contained 765 MBoe of estimated net proved reserves.

Skiatook Project. The Skiatook Waterflood Project is in the Skiatook Field, an oil-weighted field located in Osage County, Oklahoma. Since its discovery in 1919, the Skiatook Field has produced approximately 1,184 MBoe. Production from the Skiatook Project is primarily from the Bartlesville and Burgess formations at an average depth of approximately 1,600 feet. The Skiatook Project was developed by and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during December 2006, and production response to injection started in January 2008. We own 13 gross (13 net) producing and 3 gross (3 net) injection wells in this field with a working interest of 100%. As of June 30, 2012, our properties in this field were producing 43 Boe per day gross, 36 Boe per day net. As of December 31, 2011, our properties in the Skiatook Project contained 426 MBoe of estimated net proved reserves.

Hugoton Basin

War Party I and II Units. The War Party I and II Units are in the SE Guymon Field, an oil-weighted field located in Texas County, Oklahoma. The War Party I and II Units were formed as waterflood units in 2001 and 2002, respectively. War Party I and II Units have collectively produced approximately 5,464 MBoe since discovery. Production from the War Party I and II Units is from the Cherokee formation at an average depth of approximately 5,800 feet. The War Party I and II Units are operated by our affiliate, Mid-Con Energy Operating, and both are being produced under waterflood. Injection began during November 2001 and July 2002 for War Party I Unit and War Party II Unit, respectively, and production response to injection started in February 2002 and March 2003 for War Party I Unit and War Party II Unit, respectively. We own 26 gross (18 net) producing, 13 gross (9 net) injection, 8 gross (5 net) shut-in and 3 gross (2 net) recently drilled but not completed wells in both units with an average working interest in War Party I of 86% and in War Party II of 54%. As of June 30, 2012, our properties in these units were producing 268 Boe per day gross, 160 Boe per day net. As of December 31, 2011, our properties in the War Party I and II Units together contained 742 MBoe of estimated net proved reserves.

Harker Ranch Unit. The Harker Ranch Unit is in the Harker Ranch Field, an oil-weighted field located in Cheyenne County, Colorado. Since its discovery in 1989, the Harker Ranch Unit has produced over 1,082 MBoe. Production from the Harker Ranch Field is from the Morrow formation at an average depth of approximately 5,200 feet. The Harker Ranch Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during September 2006, and production response to injection started in May 2008. We own 3 gross (3 net) producing and 2 gross (2 net) injection wells in this unit with a working interest of 100%. As of June 30, 2012, our properties in this unit were producing 72 Boe per day gross, 59 Boe per day net. As of December 31, 2011, the Harker Ranch Unit contained 318 MBoe of estimated net proved reserves.

Other Properties

Decker Unit. The Decker Unit is in the NW Little Field, an oil-weighted field located in Seminole County, Oklahoma. Since its discovery in 1954, the Decker Unit has produced approximately 575 MBoe. Production from the Decker Unit is from the Earlsboro formation at an average depth of approximately 3,600 feet. The Decker Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during December 2008, and production response to

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injection started in September 2009. We own 6 gross (6 net) producing and 4 gross (4 net) injection wells in this unit with an average working interest of 98%. As of June 30, 2012, our properties in this unit were producing 24 Boe per day gross, 19 Boe per day net. As of December 31, 2011, the Decker Unit contained 216 MBoe of estimated net proved reserves.

The balance of the Company s properties, located throughout the State of Oklahoma, consist of a mix of operated and non-operated properties, none of which are under waterflood. As of December 31, 2011, our other properties contained 120 MBoe of estimated net proved reserves and generated average net production of 57 Boe per day for the month ended June 30, 2012.

Oil and Natural Gas Reserves and Production

Internal Controls Relating to Reserve Estimates

Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by our reservoir engineering staff. Reserves are reviewed internally by our senior management on a quarterly basis. Cawley, Gillespie & Associates, Inc., our independent reserve engineers, audits our reserve estimates 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 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 are considered to be analogous based on production performance from the same formation and similar completion techniques.

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Qualifications of Responsible Technical Persons

Internal Mid-Con Energy Operating Person. Robbin W. Jones, P.E., Vice President and Chief Engineer of our general partner, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Mr. Jones has over 30 years of industry experience with positions of increasing responsibility in management, production, reservoir engineering and reserve evaluations with companies such as Enserch Exploration, Caruthers Producing, Diamond Energy Operating Company, Equinox Oil Company and Schlumberger Data & Consulting Services. In 1981, he received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa. He is a Registered Professional Engineer in the States of Louisiana and Texas and a member of the Society of Petroleum Engineers.

Cawley, Gillespie & Associates, Inc. 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 Affiliates, Mid-Con Energy Operating, Yorktown 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. Cawley, Gillespie & Associates, Inc. has not performed other work for the Mid-Con Affiliates or Mid-Con Energy Operating. Cawley, Gillespie & Associates, Inc. has performed services for certain of Yorktown s portfolio companies. 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 29 years of experience in reserves evaluation. Mr. Ravnaas received a BS with special honors in Chemical Engineering from the University of Colorado at Boulder in 1979, and a M.S. 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.

Estimated Proved Reserves

The following table presents our estimated net proved oil and natural gas reserves and the standardized measure amounts associated with our estimated proved reserves attributable to our properties as of December 31, 2011 based on a reserve report prepared by our reservoir engineering staff and audited by Cawley, Gillespie & Associates, Inc.

	December 31, 2011
Reserve Data(1):	
Estimated proved reserves (MBoe)	10,049
Estimated proved developed reserves (MBoe)	6,948
Estimated proved undeveloped reserves (MBoe)	3,101
Standardized Measure (in millions)(2)	$ 328

(1) Our estimated net proved reserves and related standardized measure 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 prices for the prior twelve months were $96.19 per Bbl for oil and $4.11 per MMBtu for natural gas at December 31, 2011. 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.

(2) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69 Disclosures About Oil and Gas Producing Activities, as codified in ASC Topic 932, *Extractive*

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Activities Oil and Gas. 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. For a description of our commodity derivative contracts, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Derivative Contracts.

The data in the table above represent estimates only. Oil and gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and 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, please read Risk Factors Risks Related to Our Business 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.

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 shown above 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.

Changes in Total Proved and Proved Developed Reserves

These reserve estimates were prepared in accordance with the SEC s rules regarding oil and natural gas reserve reporting that are currently in effect. From December 31, 2010 to December 31, 2011 our proved reserves increased by approximately 2.9 MMBoe, or 41%. Total proved reserves increased by approximately 0.9 MMBoe from acquisitions in the Hugoton Basin and Northeastern Oklahoma core areas; 0.8 MMBoe from waterflood expansion in the Northeastern Oklahoma core area; 0.7 MMBoe from infill drilling in Southern Oklahoma core areas; 0.7 MMBoe from drilling and workovers in Northeastern Oklahoma and the Hugoton Basin core area and (0.3) MMBoe in net performance revisions for all of our properties. We spent a total of $19.3 million and $30.0 million in capital expenditures for the year ended December 31, 2010 and the year ended December 31, 2011, respectively, which contributed to the increase in our December 31, 2011 proved reserves.

From December 31, 2010 to December 31, 2011, our proved developed reserves increased by approximately 3.1 MMBoe, or 87%. Proved developed reserves increased in our Southern Oklahoma core area by 0.9 MMBoe from development drilling and 0.7 MMBoe in performance revisions; in the Hugoton Basin core area by 0.7 MMBoe from the acquisition of the War Party I and II Units; in our Northeastern Oklahoma core area by 0.2 MMBoe from acquisitions, 0.7 MMBoe from infill drilling and workovers and (0.1) MMBoe in net performance revisions for the Hugoton Basin and Northeastern Oklahoma core areas and other properties.

During the year ended December 31, 2011, we spent approximately $21.9 million in our Southern Oklahoma core area resulting in production increases and reclassifications of 0.9 MMBoe from proved undeveloped reserves to proved developed reserves, which contributed to the 1.6 MMBoe increase in proved developed reserves in our Southern Oklahoma core area disclosed in the prior paragraph. Additionally, we spent approximately $13.2 million during the year ended December 31, 2011 to acquire

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new leases in the Hugoton Basin and Northeastern Oklahoma. We spent another $2.4 million on workover activities and $3.4 million on drilling during the year ended December 31, 2011 in Northeastern Oklahoma.

Development of Proved Undeveloped Reserves

The following table represents a summary of activity within our proved undeveloped reserve category for the year ended December 31, 2011:

	Oil (MBbl)	Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves-beginning of year	3,406	0	3,406
Transferred to proved developed through drilling	(950)	(7)	(951)
Increase (decrease) due to evaluation reassessments and drilling results, net	481	(12)	479
Acquisition of reserves	164	0	164
Reduction of proved developed reserves aged five or more years	0	0	0
Proved undeveloped reserves-end of year	3,101	(19)	3,098

None of our proved undeveloped reserves at December 31, 2011 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. Historically, our capital expenditures were substantially funded from investment capital, bank debt and cash flow from operations. 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 through drilling is attributable to development costs incurred in prior years. During 2011, our capital expenditures for development drilling were approximately $24.5 million. Based on our current expectations of our cash flow, we believe that we can fund the development of our proved undeveloped reserves associated with our waterflood operations from our cash flow from operations and, if needed, borrowings from our credit facility. For a more detailed discussion of our liquidity position, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

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Production, Revenues and Price History

The following table sets forth information regarding combined net production of oil and certain price and cost information based on historical information for each of the periods presented:

	Mid-Con Energy Corporation (consolidated)	Mid-Con Energy Partners, LP				
	Year Ended June 30, 2009	Six Months Ended December 31, 2009	Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011	2012
Production and operating data: Net production volumes:						
Oil (MBbls)	153	87	228	407	167	304
Natural gas (MMcf)	341	140	191	164	79	60
Total (MBoe)	210	110	260	434	180	314
Average net production (Boe/d)	575	602	710	1,191	994	1,725
Average sales price:(1)						
Oil (per Bbl)	$ 66.87	$ 65.85	$ 73.92	$ 90.45	$ 93.47	$ 95.39
Natural gas (per Mcf)	$ 6.37	$ 5.31	$ 7.42	$ 7.43	$ 8.33	$ 5.88
Average price per Boe	$ 59.13	$ 58.84	$ 70.27	$ 87.63	$ 90.37	$ 93.47
Average unit costs per Boe:						
Oil and natural gas production expenses	$ 25.56	$ 22.10	$ 23.99	$ 19.56	$ 19.72	$ 15.05
Production taxes	$ 3.00	$ 2.45	$ 3.16	$ 4.31	$ 3.64	$ 2.27
General and administrative and other	$ 8.41	$ 6.40	$ 3.78	$ 4.43	$ 2.97	$ 15.51
Depreciation, depletion and amortization	$ 10.01	$ 21.43	$ 20.02	$ 15.66	$ 11.56	$ 15.00

(1) Prices do not include the effects of derivative cash settlements.

Development Activities

In December 2011, we substantially completed an extensive program that we originally undertook in January 2010 which consisted of drilling approximately 83 gross (52 net) development wells, mostly in our Southern Oklahoma core area. Approximately 70% of these development wells are producing wells, and the remainder are injection wells. The program has successfully increased injection and production. We expect that this program will result in modest future capital expenditure requirements.

In our Northeastern Oklahoma core area, since early 2010, we have been engaged in an active acquisition and corresponding exploitation program in our Cleveland Field. We have acquired a number of leases adjacent to our legacy properties that have been operated since 1985. These acquisitions have resulted in an approximately doubling of our acreage position in the field. Our exploitation program has consisted of drilling new wells, returning wells to production on acquired leases, recompleting shallower horizons and expanding waterflood operations to include previously unflooded reservoirs.

Effective June 1, 2011, we acquired two waterflood units, War Party I and II Units, in our Hugoton Basin core area. We engaged in a workover program to return a number of inactive wells in these units to

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production, to optimize producing well rates and to increase injection. This program was substantially completed on October 31, 2011.

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,						Six Months Ended	
	2009		2010		2011		2012	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells:								
Productive	7	2	21	13	34	21	11	7
Injection	1	1	10	5	12	9	3	2
Dry			4	2	2	1	0	0
Exploratory wells:								
Productive							0	0
Dry							0	0
Total wells:								
Productive	7	2	21	13	34	21	11	7
Injection	1	1	10	5	12	9	3	2
Dry			4	2	2	1	0	0
Total	**8**	**3**	**35**	**20**	**48**	**31**	**14**	**9**

We are currently conducting multiple development activities, including the drilling of 1 gross (1 net) production well in our Southern Oklahoma core area. Because we focus primarily on secondary recovery, our drilling activity is not indicative of our development activity as is typical with oil and gas exploration and primary production companies. Additionally, we are in the process of completing 1 gross (1 net) recently drilled well in our Southern Oklahoma core area and 1 gross (1 net) recently drilled well in our Northeastern Oklahoma core area.

Productive Wells

The following table sets forth information at June 30, 2012 relating to the productive wells in which we owned a working interest as of that date. 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.

	Oil		Natural Gas		Injection		Water Supply		Shut-in/ Waiting on Completion		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated	314	222	1	1	149	97	13	10	81	67	558	397
Non-operated	1	0	4	1	0	0	0	0	0	0	5	1
Total	**315**	**222**	**5**	**2**	**149**	**97**	**13**	**10**	**81**	**67**	**563**	**398**

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Developed Acreage

The following table sets forth information as of June 30, 2012 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table. As of June 30, 2012 substantially all of our leasehold acreage was held by production.

	Developed Acreage	
	Gross	**Net**
Southern Oklahoma	8,664	5,214
Northeastern Oklahoma	6,319	3,939
Hugoton Basin	5,952	4,373
Other	1,281	763
Total	**22,216**	**14,289**

Delivery Commitments

We will have no delivery commitments with respect to our production upon the closing of this offering.

Operations

General

Mid-Con Energy Operating operated approximately 99% of our properties, as calculated on a Boe basis as of December 31, 2011. 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 names 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.

Our affiliate, Mid-Con Energy Operating, provides certain services to us, including management, administrative, operational, marketing, geological and engineering services, pursuant to a services agreement.

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 27 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 read Certain Relationships and Related Party Transactions Services Agreement.

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 read Certain Relationships and Related Party Transactions Services Agreement.

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 10% to 33%, resulting in a net revenue interest to us ranging from 67% to 87.5%, or 84.1% on average, on a 100% working interest basis. Based on the standardized measure, our value-weighted average net revenue interest on our properties was approximately 81.8%, on a 100% working interest basis, based on our December 31, 2011 audited reserves. Most of our leases are held by production and do not require lease rental payments.

Marketing and Major Customers

For the year ended December 31, 2011, purchases by Sunoco Logistics accounted for approximately 86% of our total sales revenues. In 2012, we entered into crude oil purchase agreements with Enterprise, Vitol and Coffeyville Resources. For the six months ended June 30, 2012, sales to Enterprise, Sunoco Logistics and Vitol accounted for approximately 54%, 37% and 2%, respectively, of our total sales. We do not currently sell any production to Sunoco Logistics. After June 30, 2012, we expect that Vitol and Coffeyville Resources will each account for significantly higher percentages of our total sales. By selling our production to fewer purchasers, 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.

The loss of any of our customers could temporarily delay production and sale of our oil and natural gas. If we lose any of our significant customers, we believe that under current market conditions, 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. For a discussion of risks associated with our relationship with our significant customers, please read Risk Factors Risks Related to Our Business. 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 lost any of those customers.

Hedging Activities

We intend to enter into commodity derivative contracts with unaffiliated third parties to achieve more predictable cash flow and to reduce our exposure to short-term fluctuations in oil and natural gas prices. Our

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current commodity derivative contracts are primarily fixed price swaps (with collars) with NYMEX prices and option agreements. For a more detailed discussion of our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosure About Market 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. 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.

We are also 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 prices 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 in all material respects as described in this prospectus.

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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 and Colorado 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. All 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 32% of our total estimated proved reserves as of December 31, 2011, will be subject to hydraulic fracturing. Although the cost of each well will vary, on average approximately 12.5% 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. Of our $5.0 million of estimated maintenance capital expenditures for the year ended December 31, 2012, approximately $0.6 million is expected to be attributable to hydraulic fracturing.

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. For example, a typical hydraulic fracture stimulation on a Marcellus shale well is pumped in five or more stages, utilizing a total of 4 million gallons of water and 1.5 million pounds of sand. In comparison, for our wells, a large hydraulic fracture stimulation on one of our new wells would be pumped in three stages utilizing a total of 50,000 gallons of water and 60,000 pounds of sand. Typical hydraulic fracture stimulation for a recompletion of one of our existing wells would be pumped in one stage, utilizing about 20,000 gallons of water and 15,000 pounds of sand.

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. These protective measures include setting surface casing below the deepest known depth of all subsurface potable water, a depth sufficient to protect fresh water zones as determined by regulatory agencies, and cementing the well casing to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design essentially eliminates a pathway for underground migration of the fracturing fluid to contact any fresh or potable water aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval. Chemical additives used in hydraulic fracturing are described in our hydraulic fracturing contractor s material safety data sheets which describe their proper use and safe handling procedures. Fracturing contractor employees are trained in the safe handling of all fracturing fluids, chemical additives and materials and are required to wear appropriate protective clothing, eye and foot wear. Other protective measures include extensive safety briefings prior to conducting fracturing operations, testing of pumping equipment and surface lines to pressures exceeding expected maximum fracture treating pressures prior to conducting fracturing operations, detailed fracture treating process checklists used by our fracturing contractors, and guidelines for the disposal of excess fracturing fluids.

Fracture treating rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on surface pumping equipment and associated treating lines, the treating string and, where applicable, the immediate annulus to the treating string. Hydraulic fracturing operations would be shut down if an abrupt change occurred in the treating pressure or annular pressure.

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Regulations applicable to our operating areas do not currently require, and we do not currently evaluate, the environmental impact of typical additives used in fracturing fluid. We note, however, that approximately 98% of the hydraulic fracturing fluids we use are made up of water and sand.

We minimize the use of water and dispose of it in a way that essentially eliminates the impact to nearby surface water by disposing excess water and water that is produced back from the wells into approved disposal or injection wells. We currently do not intentionally discharge water to the surface.

To our knowledge, there have not been any incidents, citations or suits related to environmental concerns from our fracturing operations.

If a surface spill or a leak were to occur, it would be controlled, contained and remediated in accordance with the applicable requirements of state oil and gas commissions, as well as any Spill Prevention, Control and Countermeasures, or SPCC, plans we maintain in accordance with EPA requirements. This would include any action up to and including total abandonment of the wellbore.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean up costs stemming from a sudden and accidental pollution event. We may not have coverage if we are unaware of the pollution event and unable to report the occurrence to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read Environmental Matters and Regulation Hydraulic Fracturing. For related risks to our unitholders, please read 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.

We maintain insurance coverage against potential losses that we believe is customary in the industry. We currently maintain general liability insurance and commercial umbrella liability insurance with limits of $1 million and $5 million per occurrence, respectively, and $2 million and $5 million in the aggregate, respectively. There is a $1,000 per claim deductible for only our property damage liability and our containment and pollution coverage included as part of our general liability insurance and a $10,000 retention for our commercial umbrella liability insurance. Our general liability insurance covers us for, among other things, legal and contractual liabilities arising out of property damage and bodily injury, for sudden or accidental pollution liability. Our commercial umbrella liability insurance is in addition to and triggered if the general liability insurance policy limits are exceeded. In addition, we maintain control of well insurance with per occurrence limits of $5 million and retentions of $50,000. Our control of well policy insures us for blowout risks associated with drilling, completing and operating our wells, including above-ground pollution.

Our current insurance policies provide coverage for losses arising out of our hydraulic fracturing operations. These policies may not cover fines, penalties or costs and expenses related to government mandated clean-up of pollution. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you 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.

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Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state, tribal 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 well sites. 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, storage, 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 assure you 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, or 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 federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or legality of conduct, on certain classes of persons who are 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 entities that 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. We generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA.

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, leased or operated 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 or release 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, or 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. 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. SPCC 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 require 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, or the 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

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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, or 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 relating 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 begun the process of drafting guidance documents related to this newly asserted regulatory authority. 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. On July 1, 2012, the Oklahoma Corporation Commission adopted new 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. Certain proprietary information may be excluded from an operator s disclosure. The new disclosures apply to horizontal wells that are hydraulically fractured on or after January 1, 2013 and to other wells that are hydraulically fractured on or after January 1, 2014. Additionally, some states, including Texas, 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 required certain oil and gas operators to cease water injection associated with hydraulic fracturing activities due to concern that such activities may be related to increased earthquake activity. 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. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation 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, with initial results expected to be available by late 2012 and final results by 2014. The EPA has also announced that it is launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. 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. The U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. 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.

To our knowledge, there have not been any citations, suits or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

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 April 17, 2012, the EPA approved 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 VOCs, 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 occurring 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 GHGs, present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first requires a reduction in emissions of GHGs from motor vehicles. The second requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. On May 12, 2010, the EPA also issued a new tailoring rule, which makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. On September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. In addition, on November 30, 2010, the EPA published a final rule that expands its existing GHG emissions reporting rule to include certain owners and operators of onshore oil and natural gas production to monitor GHG emissions beginning in 2011 and to report those emissions beginning in 2012. 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 GHGs 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 GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur significant costs to reduce emissions of GHGs 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, or 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 analyses 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, as amended, or ESA, may restricts activities that may 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.

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OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or 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, or 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, or 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 EPAct 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, or FTC, and the 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 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 EPAct 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, natural gas liquids, 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. FERC has also established market-based rates and settlement rates as alternative forms of ratemaking in certain circumstances.

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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 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, where most of our properties are currently located, 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, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%. A portion of our wells in the State of 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 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. Increased federal and state safety regulation could affect the availability and cost of pipeline transportation to us.

At the federal level, on January 3, 2012, President Obama signed the 2011 Pipeline Safety Act, which act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the

U.S. Secretary of Transportation to evaluate or promulgate stricter safety rules or standards for liquids and gas interstate pipelines. On August 13, 2012, the federal Pipeline and Hazardous Materials Safety Administration, or PHMSA, published a proposed rulemaking consistent with the signed act that, once finalized, will increase the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after January 3, 2012 to $200,000 per violation per day of violation, with a maximum of $2,000,000 for a related series of violations. In addition, PHMSA published a final rule in May 2011 expanding pipeline safety requirements including added reporting obligations and integrity management standards to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner. In August 2011 and October 2010, PHMSA published advance notices of proposed rulemakings with respect to gas and oil pipelines respectively, in which the agency is seeking public comment on a number of changes to regulations governing pipeline safety, and, in May 2012, PHMSA issued an advisory bulletin regarding the adequacy of records that could result in reduced operating pressures on certain pipelines.

Numerous state agencies have been certified to enforce the federal rules and standards, and state agencies often adopt and enforce state-wide safety rules and standards governing intrastate pipelines, which may be as restrictive or more restrictive than the federal rules and standards. Similar to federal regulation, state regulation has become increasingly stringent in recent years and state regulation may continue to increase in the immediate future.

Employees

The officers of our general partner manage our operations and activities. Neither we, our subsidiary, nor our general partner have employees. Mid-Con Energy Operating performs services for us, including the operation of our properties, pursuant to the services agreement between it and our general partner. Please read Certain Relationships and Related Party Transactions Services Agreement. Mid-Con Energy Operating has more than 65 employees performing services for our operations and activities. We believe that Mid-Con Energy Operating has a satisfactory relationship with those employees.

Offices

Our headquarters are located at 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201, with approximately 3,853 square feet of office space under lease. Our Dallas lease expires in 2016. For our principal operating office, we currently lease approximately 13,545 square feet of office space in Tulsa, Oklahoma at 2431 East 61st Street, Suite 850, Tulsa, Oklahoma 74136. Our Tulsa lease expires in December 2016.

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.

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MANAGEMENT

Management of Mid-Con Energy Partners, LP

Our general partner manages our operations and activities on our behalf through its executive officers and board of directors. References in this prospectus 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, each of whom will be appointed by the Founders, or directly or indirectly participate in our management or operations. Further, our partnership agreement contains provisions that substantially restrict the fiduciary duties that our general partner would otherwise owe to our unitholders under Delaware law. Please read Conflicts of Interest and Fiduciary Duties Fiduciary Duties.

The board of directors of our general partner has seven 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. Please read Director Independence and Committees of the Board of Directors below.

All of the executive officers of our general partner are also officers and/or directors of the 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 the 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 the Mid-Con Affiliates. Please read Certain Relationships and Related Party Transactions Services Agreement. We expect the executive officers of our general partner and other shared personnel to devote a sufficient amount of time to our business and affairs as is necessary for the proper management and conduct of our business and operations. However, the executive officers of our general partner and other shared personnel also devote substantial amounts of their time to managing the businesses of the Mid-Con Affiliates.

Directors and Executive Officers of Mid-Con Energy GP, LLC

The following table sets forth certain information regarding the current directors and executive officers of our general partner.

Name	Age	Position with Mid-Con Energy GP, LLC
S. Craig George	60	Executive Chairman of the Board
Charles R. Randy Olmstead	64	Chief Executive Officer and Director
Jeffrey R. Olmstead	35	President, Chief Financial Officer and Director
David A. Culbertson	47	Vice President and Chief Accounting Officer
Robbin W. Jones	53	Vice President and Chief Engineer
Nathan P. Pekar	36	Vice President, General Counsel and Secretary
Peter A. Leidel	56	Director
Cameron O. Smith	62	Director
Robert W. Berry	88	Director
Peter Adamson III	71	Director

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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 Affiliates. 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. In evaluating director candidates, the Founders will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the ability of the board of directors to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the board to fulfill their duties. While the Founders may consider diversity among other factors when considering director nominees, they do not apply any specific diversity policy with regard to selecting and appointing directors to the board of directors. However, when appointing new directors, the Founders will consider each individual director s qualifications, skills, business experience and capacity to serve as a director, and the diversity of these attributes for the board of directors as a whole.

S. Craig George serves as Executive Chairman of the board of directors of our general partner. Mr. George has been a member of the board of directors of Mid-Con Energy III, LLC, Mid-Con Energy IV, LLC and Mid-Con Energy Operating since June 2011. Mr. George was previously a member of the board of directors of Mid-Con Energy I, LLC following its formation in 2004 and of Mid-Con Energy II, LLC since its formation in 2009. 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 1975-1981, Mr. George held engineering and management positions with Amoco Production Company. Mr. George is a graduate of Missouri University of Science and Technology, with a Bachelor of Science degree in Mechanical Engineering, and of Aquinas Institute, with a Master of Arts in Theology. We believe that Mr. George s service as the chief executive officer and a director of a publicly traded exploration and production company brings important experience and leadership skill to the board of directors of our general partner.

Charles R. Randy Olmstead serves as Chief Executive Officer and as a member of the board of directors of our general partner. Mr. Olmstead has been Chief Executive Officer and Chairman of the board of directors of Mid-Con Energy III, LLC and Mid-Con Energy IV, LLC since June 2011. Mr. Olmstead previously served as President, Chief Financial Officer and Chairman of the board of directors of Mid-Con Energy I, LLC following its formation in 2004 and of Mid-Con Energy II, LLC following its formation in 2009. 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 from the University of Oklahoma with Bachelors of Business Administration degrees in finance and accounting before serving three years in the US Navy. We believe that Mr. Olmstead s extensive experience in the oil and gas industry brings important experience and leadership skill to the board of directors of our general partner.

Jeffrey R. Olmstead serves as President, Chief Financial Officer and as a member of the board of directors of our general partner. Mr. Olmstead has been a member of the board of directors of Mid-Con Energy III, LLC and President, Chief Financial Officer and a member of the board of directors of Mid-Con Energy IV, LLC since June 2011 and of Mid-Con Energy Operating since 2007. Mr. Olmstead was previously a member of the board of directors of Mid-Con Energy I, LLC and of Mid-Con Energy II, LLC following its formation. 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 in the bank s energy group. Mr. Olmstead is a graduate of Vanderbilt University, with a Bachelor of Engineering degree in Electrical Engineering and Math, and of the Owen School of Business at Vanderbilt University, with a Master of Business Administration. We believe that Mr. Olmstead s experience in energy-related finance brings important experience and leadership skill to the board of directors of our general partner.

David A. Culbertson serves as Vice President and Chief Accounting Officer of our general partner. Mr. Culbertson previously served as Controller of Mid-Con Energy I, LLC after 2006 and of Mid-Con Energy II, LLC following its formation in 2009. He has also supervised the accounting function for affiliates of our predecessor. Prior to joining us in 2006, Mr. Culbertson served in various accounting positions with Vintage Petroleum from 2003-2006, The Williams Companies from 1999-2003 and Samson Resources from 1989-1999. Mr. Culbertson is a graduate of Oklahoma State University, with a Bachelor of Business Administration degree in accounting, and of the University of Tulsa, with a Master of Business Administration. He is a Certified Public Accountant.

Robbin W. Jones, P.E. serves as Vice President and Chief Engineer of our general partner. Mr. Jones was elected President of Mid-Con Energy III, LLC in June 2011. Mr. Jones previously served as a Vice President and Chief Operating Officer of the predecessor and affiliate companies since 2007. Mr. Jones served as reservoir engineer and manager of our Houston office from March 2005, when he joined our predecessor, until 2007. Mr. Jones served as manager at Schlumberger Data & Consulting Services from 2004 to 2005 and has twenty years of engineering experience in all phases of waterflood development and management working for Enserch Exploration, Caruthers Producing, Diamond Energy Operating Company and Equinox Oil Company. Mr. Jones received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa. He is a Registered Professional Engineer in the states of Louisiana and Texas and a member of the Society of Petroleum Engineers.

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 in positions of increasing responsibility, and ultimately as General Counsel and Business Development Manager with Matador Resources Company from 2007-2012, during which time he assisted it in becoming a public company. Prior to this, Mr. Pekar was in private practice from 2003 to 2007. Mr. Pekar is a graduate of The University of Texas, with a Bachelor of Business Administration degree in Finance, and of Southern Methodist University, with a Juris Doctor degree. He is a licensed attorney in the State of Texas.

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, Mid-Con Energy IV, LLC and Mid-Con Energy Operating since June 2011. Mr. Leidel has been a member of the board of directors of Mid-Con Energy I, LLC since its formation in 2004 and of Mid-Con Energy II, LLC since its formation in 2009. Previously, he was a partner of Dillon, Read & Co. Inc., held corporate treasury positions at Mobil Corporation and 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 is a graduate of the University of Wisconsin, with a Bachelor of Business Administration degree in accounting and of the Wharton School at the University of Pennsylvania, with a Master of Business Administration. We believe that Mr. Leidel s extensive financial and private investment experience, as well as his experience on the boards of directors of numerous public and private companies (including prior service as the chairman of the audit committees of two public companies), bring substantial leadership skill and experience to the board of directors.

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Cameron O. Smith serves as a member of the board of directors of our general partner. In January 1992, Mr. Smith founded, and until June 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 when it was sold to Rodman & Renshaw, LLC, a full service investment bank. From 2008 until December 2009, Mr. Smith served Rodman & Renshaw, LLC as a Senior Managing Director and Head of The Rodman Energy Group. Between January 2010 and late 2011, Mr. Smith enjoyed a sabbatical from business. Toward the end of 2011, Mr. Smith re-engaged in the oil and gas business, joining our general partner s board of directors and accepting a position as Senior Advisor to the Energy Group of Warburg Pincus LLC, a large private equity fund based in New York City. From 1975 until 1978, Mr. Smith worked as an exploration geologist for various public oil companies founded by his family. In 1978, he formed his own exploration company, Taconic Petroleum corporation, headquartered in Tulsa, Oklahoma, which he ran until the end of 1991. Mr. Smith received a Master of Science in Geology degree from Pennsylvania State University in 1975 and an A.B. in Art History from Princeton University in 1972. We believe that Mr. Smith s extensive financial and private equity experience, as well as his experience in the oil and natural gas industry generally, bring substantial leadership skill and experience to the board of directors.

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 from the University of Oklahoma with a Bachelor of Science degree in Geology. We believe that Mr. Berry s extensive experience in the oil and gas industry brings substantial leadership skill and experience to the board of directors of our general partner.

Peter Adamson III serves as a member of the board of directors of our general partner. Mr. Adamson is a founder of Adams Hall Asset Management LLC, a Tulsa, Oklahoma based registered investment advisor with over $1 billion under management, to which he now functions as 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. We believe that Mr. Adamson s extensive financial and investing experience bring substantial leadership skill and experience to the board of directors.

Reimbursement of Expenses of Our General Partner

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and our other affiliates, including Mid-Con Energy Operating, may be reimbursed. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

Mid-Con Energy Operating provides management, administrative and operational services to us pursuant to a 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

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services for us or on our behalf and other expenses allocated 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. For further discussion of the reimbursements that Mid-Con Energy Operating will be entitled to receive relating to services provided in connection with the services agreement, please read Certain Relationships and Related Party Transactions Services Agreement.

Director Independence

Messrs. Berry, Smith and Adamson meet the independence standards established by the NASDAQ listing rules.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee and a conflicts committee. We do not have a compensation committee, but rather an appointed committee approves equity grants to directors and employees. As noted above, the NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NASDAQ listing rules and rules of the SEC. 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 also is 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. Currently, Messrs. Berry, Smith and Adamson serve on the audit committee.

Conflicts Committee

Our partnership agreement requires that at least two independent members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board of directors believes may involve conflicts of interest (including certain transactions with affiliates of our general partner, including the Mid-Con Affiliates) and that it determines to submit to the conflicts committee for review. Our general partner may, but is not required to, seek approval from the conflicts committee of a resolution of a conflict of interest with our general partner or affiliates. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, including the Mid-Con Affiliates or holders of any ownership interest in our general partner or any of its affiliates, other than common units or securities exercisable, convertible into or exchangeable for common units, and must meet the independence standards established by the NASDAQ listing rules and the Securities Exchange Act of 1934 to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee will be conclusively deemed to have been approved in good faith. In addition, any such matters will be deemed to be approved by all of our partners and not constitute a breach of our partnership agreement or of any duties our general partner may owe us or our unitholders. Please read Conflicts of Interest and Fiduciary Duties Conflicts of Interest. Currently, Messrs. Berry, Smith and Adamson serve on the conflicts committee.

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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. Our general partner s board of directors has also determined that having the Chief Executive Officer serve as a director could 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 may be defined as the process of identification, management 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 will offer an enterprise-level risk assessment to the board of directors at least once every year.

We and our general partner were formed in July 2011. The executive officers of our general partner are also executive officers and/or directors of the Mid-Con Affiliates. These executive officers devote a sufficient amount of time to our business and affairs as is necessary for the proper management and conduct of our business and operations. However, these executive officers also devote substantial amounts of time to managing the businesses of the Mid-Con Affiliates. The executive officers of our general partner currently devote their business time to our business as follows: S. Craig George, Charles R. Olmstead, Jeffrey R. Olmstead, David A. Culbertson, and Robbin W. Jones devote approximately 80%, $66^2/_3$%, 80%, $66^2/_3$% and 50% of their business time, respectively. The amount of time that each of our executive officers devotes to our business is subject to change depending on our activities, the activities of the Mid-Con Affiliates to which they also provide services, and any acquisitions or dispositions made by us or the Mid-Con Affiliates.

Because the executive officers of our general partner are employees of Mid-Con Energy Operating, their compensation is paid by Mid-Con Energy Operating and we reimburse Mid-Con Energy Operating pursuant to the services agreement for the portion of such compensation allocable to us. Please read Certain Relationships and Related Party Transactions Services Agreement.

Compensation Committee Interlocks and Insider Participation

The NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee. Although the board of directors of our general partner does not currently intend to establish a compensation committee, it may do so in the future.

Compensation Discussion and Analysis

This Compensation Discussion and Analysis provides information regarding the executive compensation program for our Chief Executive Officer, our Chief Financial Officer and our three executive officers (other than the Chief Executive Officer and Chief Financial Officer) who were the most highly compensated executives at the end of the last completed fiscal year, or the named executive officers.

The following individuals were our named executive officers as of December 31, 2011:

- Charles R. Olmstead, Chief Executive Officer;
- S. Craig George, Executive Chairman of the Board;

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Jeffrey R. Olmstead, President, Chief Financial Officer;

David A. Culbertson, Vice President, Chief Accounting Officer; and

Robbin W. Jones, Vice President and Chief Engineer.

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 will reimburse our general partner for payments it makes to Mid-Con Energy Operating. Please read Certain Relationships and Related Party Transactions Services Agreement and Reimbursement of Expenses of Our General Partner.

We and our general partner were formed in July 2011; therefore, we incurred no cost or liability with respect to the compensation of our executive officers, nor has our general partner accrued any liabilities for management incentive or retirement benefits for our executive officers for the fiscal year ended December 31, 2010 or for any prior periods. Accordingly, we are not presenting any compensation information for historical periods.

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 predecessor historically compensated its executive officers primarily with base salary and cash bonuses.

Our general partner also grants equity-based awards to our executive officers pursuant to a long-term incentive program. Annual bonuses payable to our executive officers will be determined based on our financial performance as measured across a fiscal year. However, incentive compensation in respect of services provided to us will not be tied in any way to the performance of entities other than our partnership. Specifically, any performance metrics will not 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 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 short and long-term disability coverage. Employees provided to us under the services agreement will be entitled to the same basic benefits.

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Employment Agreements

Our general partner has entered into employment agreements with each of the following named employees of our general partner: Charles R. Olmstead, Chief Executive Officer; Jeffrey R. Olmstead, President and Chief Financial Officer; and S. Craig George, Executive Chairman of the Board of our general partner.

The employment agreements provide for a term that commenced on August 1, 2011 and expires on August 1, 2014, unless earlier terminated, with automatic one-year renewal terms unless either we or the employee gives written notice of termination at least by February 1 preceding any such August 1. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities, and authority as the board of directors of our general partner may specify from time to time, in roles consistent with such positions that are assigned to him.

The 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

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. 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 long-term incentive program is approximately 1.8 million units. As of December 31, 2011 all of the units were available for issuance.

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Equity Compensation Program Information

Long-term incentive program category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)**	**Weighted-average exercise price of outstanding options, warrants and rights (b)**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)**
Equity compensation plans approved by security holders			1,464,451 common units
Equity compensation plans not approved by security holders			0
Total			1,464,451 common units

On January 31, 2012 and July 31, 2012, a committee administrating the program awarded units under the long-term incentive program. This committee awarded units to our executive officers, key employees, consultants and outside directors in an amount equal to 62,049 restricted units and 237,500 unrestricted units.

For additional information regarding the long-term incentive program, see Long-Term Incentive Program.

Short-Term Incentive Payments

The performance criteria for the short-term incentive plan for 2011 included 50% of the target bonus earned upon the successful completion of our initial public offering and 50% earned upon causing us to comply with current public reporting requirements of the Securities and Exchange Act of 1934 for at least six months. The performance criteria for the short-term incentive plan for 2012 includes, and for future years are expected to 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 of directors. We do not provide perquisites to the named executive officers.

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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 year ended December 31, 2011. Our named executive officers are paid by Mid-Con Energy Operating. We reimburse Mid-Con Energy Operating for a portion of its compensation according to the Services Agreement. There was not a service agreement in place prior to December 2011; therefore, no salaries or other compensation were allocated prior to December 2011.

Name and Principal Position	Year	Salary	Bonus	Unit Awards	All Other Compensation	Total
Charles R. Olmstead	2011	$ 15,361				$ 15,361
Chief Executive Officer						
S. Craig George	2011	$ 17,270				$ 17,270
Executive Chairman of the Board						
Jeffrey R. Olmstead	2011	$ 27,024				$ 27,024
President, Chief Financial Officer						
David A. Culbertson	2011	$ 11,668				$ 11,668
Vice President, Chief Accounting Officer						
Robbin W. Jones	2011	$ 12,402				$ 12,402
Vice President, Chief Engineer						

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 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

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- 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, or 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

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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, 2011, 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.

S. Craig George	Termination Upon Death, Disability or Retirement	Termination Without Cause	Termination Following Change in Control
Cash Severance	$ 640,000	$ 480,000	$ 480,000
Equity			
Restricted Stock/Units			
Performance Shares/Units	917,500	917,500	917,500
Total	1,557,500	1,397,500	1,397,500
Other Benefits			
Health & Welfare	15,428	15,428	15,428
Tax Gross-Ups			
Total	15,428	15,428	15,428
Total	$ 1,572,928	$ 1,412,928	$ 1,412,928

Charles R. Olmstead	Termination Upon Death, Disability or Retirement	Termination Without Cause	Termination Following Change in Control
Cash Severance	$ 640,000	$ 480,000	$ 480,000
Equity			
Restricted Stock/Units			
Performance Shares/Units	917,500	917,500	917,500
Total	1,557,500	1,397,500	1,397,500
Other Benefits			
Health & Welfare	15,428	15,428	15,428
Tax Gross-Ups			
Total	15,428	15,428	15,428
Total	$ 1,572,928	$ 1,412,928	$ 1,412,928

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Jeffrey R. Olmstead	Termination Upon Death, Disability or Retirement	Termination Without Cause	Termination Following Change in Control
Cash Severance	$ 760,000	$ 720,000	$ 720,000
Equity			
Restricted Stock/Units			
Performance Shares/Units	917,500	917,500	917,500
Total	1,677,500	1,637,500	1,637,500
Other Benefits			
Health & Welfare	21,182	21,182	21,182
Tax Gross-Ups			
Total	21,182	21,182	21,182
Total	$ 1,698,682	$ 1,658,682	$ 1,658,682

Long-Term Incentive Program

Our general partner adopted a long-term incentive program for employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating, who perform services for us.

The description of the long-term incentive program set forth below is a summary of the material features of the program. This summary, however, does not purport to be a complete description of all of the provisions of the program.

The type of awards that may be granted under the long-term incentive program consists of the following components: restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The purpose of awards under the long-term incentive program is to provide additional incentive compensation, at the discretion of the board or a compensation committee if the board elects to form such a committee, to employees providing services to us, and to align the economic interests of such employees with the interests of our unitholders. The long-term incentive program currently limits the number of units that may be delivered pursuant to awards to 1,764,000 common units. Common units cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The program is currently administered by a committee consisting of the Founders, which is referred to as the program administrator. The program administrator may also delegate its duties as appropriate.

Amendment or Termination of Long-Term Incentive Program

The program administrator may terminate or amend the long-term incentive program at any time with respect to any units for which a grant has not yet been made. The program administrator also has the right to alter or amend the long-term incentive program or any part of the program 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 program will expire on the earliest to occur of (i) the date on which all common units available under the program for grants have been paid to participants, (ii) termination of the program by the program administrator or (iii) December 20, 2021.

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Restricted Units

A restricted unit is a common unit that vests over a period of time, and during that time, is subject to forfeiture. Forfeiture provisions lapse at the end of the vesting period. The program administrator may make grants of restricted units containing such terms as it shall determine, including the period over which restricted units will vest. The program administrator, in its discretion, may base its determination upon the achievement of specified financial or other performance objectives. Restricted units will be entitled to receive quarterly distributions during the vesting period.

We intend the restricted units under the program to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common units. Therefore, program participants will not pay any consideration for restricted units they receive, and we will receive no remuneration for the restricted units.

Phantom Units

A phantom unit is a notional common unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the program administrator, cash equivalent to the value of a common unit. The program administrator may make grants of phantom units under the program containing such terms as the program administrator shall determine, including the period over which phantom units granted will vest. The program administrator, in its discretion, may base its determination upon the achievement of specified financial or other performance objectives.

We intend the issuance of any common units upon vesting of the phantom units under the program to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common units. Therefore, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the common units.

Unit Options

The long-term incentive program permits the grant of options covering common units. Unit options represent the right to purchase a designated number of common units at a specified price. The program administrator may make grants containing such terms as the program administrator shall determine. Unit options will have an exercise price that is not less than the fair market value of the common units on the date of grant. In general, unit options granted will become exercisable over a period determined by the program administrator.

Unit Appreciation Rights

The long-term incentive program permits the grant of unit appreciation rights. A unit appreciation right is an award that, upon exercise, entitles the participant to receive the excess of the fair market value of a common unit on the exercise date over the exercise price established for the unit appreciation right. Such excess will be paid in cash or common units. The program administrator may make grants of unit appreciation rights containing such terms as the program administrator shall determine. Unit appreciation rights will have an exercise price that is not less than the fair market value of the common units on the date of grant. In general, unit appreciation rights granted will become exercisable over a period determined by the program administrator.

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Distribution Equivalent Rights

The program administrator may, in its discretion, grant distribution equivalent rights, or DERs, in tandem with phantom unit awards under the long-term incentive program. DERs entitle the participant to receive an amount in cash, units or phantom units equal to the amount of any cash distributions made by us during the period that the phantom unit award is outstanding. Payment of a DER issued in connection with another award may be subject to the same or different vesting terms as the award to which it relates or in the discretion of the program administrator.

Other Unit-Based Awards

The long-term incentive program permits the grant of other unit-based awards, which are awards that are based, in whole or in part, on the value or performance of a common unit. Upon vesting, the award may be paid in common units, cash or a combination thereof, as provided in the grant agreement.

Unit Awards

The long-term incentive program permits the grant of common units that are not subject to vesting restrictions. Unit awards may be in lieu of or in addition to other compensation payable to the individual.

Change in Control and Anti-Dilution Adjustments

Upon a change of control (as defined in the long-term incentive program), any change in applicable law or regulation affecting the long-term incentive program or awards thereunder, or any change in accounting principles affecting the financial statements of our general partner, the program administrator, in an attempt to prevent dilution or enlargement of any benefits available under the long-term incentive program 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 program 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 program 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.

Termination of Service

The consequences of the termination of a grantee s employment, consulting arrangement or membership on the board of directors will be determined by the program administrator in the terms of the relevant award agreement or employment agreement.

Source of Common Units

Common units to be delivered pursuant to awards under the long-term incentive program 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 long-term incentive program, 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.

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Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are intended 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 may 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. Our compensation policies do not encourage excessive and unnecessary risk taking, and ensure that the level of risk is not reasonably likely to have a material adverse effect on the Partnership.

Compensation of Directors

Officers or employees of our general partner or our other affiliates, including Mid-Con Energy Operating, who also serve as directors do not receive additional compensation for their service as a director of our general partner. Each non-employee director is compensated with a combination of cash and units for their service on the board of directors. Each non-employee director has the option to elect to receive either an annual cash retainer of $40,000, paid in quarterly installments of $10,000, or an equivalent number of units issued under our long-term incentive program. In addition, each non-employee director is paid $1,000 per board meeting that the director attends and an annual $5,000 payment if he serves as the Chairman of either the audit committee or the conflicts committee. Each non-employee director is also granted 2,500 units annually under our long-term incentive program. The directors received no compensation in 2011. In January 2012, each director was awarded 2,500 common units of the Partnership.

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SELLING UNITHOLDERS

This prospectus covers the offering for resale of 3,000,000 common units, or 3,600,000, if the underwriters exercise their option to purchase additional common units in full, owned by the Selling Unitholders. These common units were obtained by the Selling Unitholders as partial consideration in respect of the merger of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC into our subsidiary in connection with our initial public offering.

Immediately before this offering, the Selling Unitholders owned 8,691,468 of our outstanding common units, representing an approximate 48.5% limited partner interest in us. Following this offering, the Selling Unitholders will own 5,691,468 common units, or 5,091,468 common units if the underwriters exercise in full their option to purchase additional common units, representing an approximate 30.1% and 26.9% limited partner interest in us, respectively. Please read Security Ownership of Certain Beneficial Owners and Management. For further discussion of the relationships between us, our general partner and Yorktown, please read Certain Relationships and Related Party Transactions.

No offer or sale under this prospectus may be made by a unitholder unless that holder is listed in the table below, in a supplement to this prospectus or in an amendment to the related registration statement that has become effective under the Securities Act.

The Selling Unitholders are not broker dealers registered under Section 15 of the Exchange Act or affiliates of a broker dealer registered under Section 15 of the Exchange Act.

The following table sets forth information relating to the selling unitholders as of October 12, 2012, based on information supplied to us by the Selling Unitholders on or prior to that date. Assuming that the Selling Unitholders sell all of the common units owned or beneficially owned by them that are offered by this prospectus and do not acquire any additional common units following this offering, the Selling Unitholders will not own any common units other than those appearing in the column entitled Common Units Held Following Offering. In addition, the Selling Unitholders may have sold, transferred or otherwise disposed of, or may sell, transfer or otherwise dispose of, at any time and from time to time, common units in transactions exempt from the registration requirements of the Securities Act of 1933 after the date as of which the information is set forth on the table below.

Selling Unitholders(1)	Common Units Held Prior to Offering	Common Units That May Be Offered	Common Units Held Following Offering(2)	Percentage of Outstanding Common Units(3)(4)
Yorktown Energy Partners VI, L.P.	3,166,888	1,093,102	2,073,786	11.0%
Yorktown Energy Partners VII, L.P.	1,583,444	546,551	1,036,893	5.5%
Yorktown Energy Partners VIII, L.P.	3,941,136	1,360,347	2,580,789	13.6%
Yorktown Total	8,691,468	3,000,000	5,691,468	30.1%

(1) Yorktown Energy Partners IX, L.P. owns a 50% interest in Mid-Con Energy Operating. Yorktown IX Company LP is the sole general partner of Yorktown Energy Partners IX, L.P. Yorktown Associates LLC is the sole general partner of Yorktown IX Company LP. Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P. own common units in us. For more information on the entities that control Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P., please read Security Ownership of Certain Beneficial Owners and Management. In addition, Peter A. Leidel, a principal of Yorktown, serves on the board of directors of our general partner.

(2) Assumes the sale of all common units held by such Selling Unitholders offered by this prospectus.

(3)

Gives effect to the issuance and sale of the 3,000,000 common units we are offering by means of this prospectus and assumes no exercise by the underwriters of their option to purchase additional common units.

(4) Based on 18,939,549 common units outstanding as of the close of this offering.

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SECURITY OWNERSHIP OF CERTAIN

BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our common units that, following this offering and assuming the underwriters do not exercise their option to purchase additional common units, will be 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(1)	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned
Yorktown Energy Partners VI, L.P.(1)(2)	2,073,786	11.0%
Yorktown Energy Partners VII, L.P.(1)(3)	1,036,893	5.5%
Yorktown Energy Partners VIII, L.P.(1)(4)	2,580,789	13.6%
Charles R. Olmstead(5)	690,278	3.6%
Jeffrey R. Olmstead(5)	230,329(6)	1.2%
Nathan P. Pekar(5)	15,000	0.08%
Robbin W. Jones(5)	228,861(7)	1.2%
David A. Culbertson(5)	74,783	0.4%
S. Craig George(5)	204,585	1.1%
Peter A. Leidel(5)	2,500	0.01%
Peter Adamson III(5)	12,500(8)	0.07%
Robert W. Berry(5)	37,500(9)	0.12%
Cameron O. Smith(5)	22,293	0.12%
All named executive officers, directors and director nominees as a group (10 persons)(5)	1,518,629	7.9 %

(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) Yorktown VIII Company LP is the sole general partner of Yorktown Energy Partners VIII, L.P. Yorktown VIII Associates LLC is the sole general partner of Yorktown VIII Company LP. As a result,

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Yorktown VIII 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 VIII, L.P. Yorktown VIII Company LP and Yorktown VIII Associates LLC disclaim beneficial ownership of the common units owned by Yorktown Energy Partners VIII, L.P. in excess of their pecuniary interests therein.

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

(6) Includes Jeffrey R. Olmstead s indirect ownership of 105,097 common units held by the Charles R. Olmstead 2011 Trust. Jeffrey R. Olmstead is a trustee of the Charles R. Olmstead 2011 Trust and has immediate family members who are beneficiaries of the trust. Jeffrey R. Olmstead disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

(7) Includes Robbin W. Jones indirect ownership of 223,861 common units held by the Jones Revocable Trust. Robbin W. Jones is a trustee of the Jones Revocable Trust and has immediate family members who are beneficiaries of the trust. Robbin W. Jones disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

(8) Includes Peter Adamson III s indirect ownership of 10,000 common units held by Cherokee 2000 Investments LLC. Peter Adamson III is the managing member of Cherokee 2000 Investments LLC. Peter Adamson III disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

(9) Includes Robert W. Berry s indirect ownership of 20,000 common units held by Berry Ventures, Inc. Robert W. Berry is the controlling shareholder of Berry Ventures, Inc. Robert W. Berry disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

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.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Following this offering, assuming the underwriters do not exercise their option to purchase additional common units, the Founders and Yorktown will own 6,816,660 common units representing an approximate 36.0% limited partner interest in us. In addition, our general partner will own an approximate 2.0% general partner interest in us, evidenced by 360,000 general partner units. These percentages do not reflect any common units that may be issued under the long-term incentive program in the future.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our ongoing operation and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, were not the result of arm s length negotiations.

Operational Stage

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions approximately 98.0% to our unitholders, pro rata, and approximately 2.0% to our general partner, based upon their respective limited and general partner interests in us.
Payments to our general partner and its affiliates	Our general partner does not receive a management fee or other compensation for its management of our partnership, but we will reimburse our general partner for all direct and indirect expenses it incurs and payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation, employment benefits and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner determines in good faith the expenses that are allocable to us.
Withdrawal or removal of our general partner	In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the departing general partner s general partner interest for a cash payment equal to the fair market value of such interest. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the departing general partner s general partner interest in us for its fair market value.

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Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Services Agreement

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, operational, marketing, geological and engineering services. Our services agreement was negotiated among affiliated parties and, consequently, is not the result of arm s length negotiations. 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. From the closing of our initial public offering through December 31, 2011, we reimbursed Mid-Con Energy Operating $0.2 million for direct operating expenses. For the six-month period ending June 30, 2012 we reimbursed Mid-Con Energy Operating $1.3 million for direct operating expenses.

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 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, 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.

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 partner s 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 governance section.

The board of directors of our general partner has a standing conflicts committee currently comprised of three independent directors. Our general partner may, but is not required to, seek the approval of the conflicts committee in connection with acquisitions of oil and natural gas properties from the Mid-Con Affiliates or any other affiliates of the general partner. In addition to acquisitions from affiliates of our general partner, the board of directors of our general partner will also determine whether to seek conflicts committee approval to the extent we act jointly to acquire additional oil and natural gas properties with

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affiliates of our general partner. In the case of any sale of equity or debt by us to an owner or affiliate of an owner of our general partner, we anticipate that our practice will be to obtain the approval of the conflicts committee of the board of directors of our general partner for the transaction. The conflicts committee is entitled to hire its own financial and legal advisors in connection with any matters on which the board of directors of our general partner has sought the conflicts committee s approval.

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.

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CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner, our general partner s affiliates (including the Mid-Con Affiliates) and Yorktown on the one hand, and us and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage the business of our general partner in a manner beneficial to its owners. In addition, all of our general partner s executive officers and non-independent directors will continue to have economic interests in affiliates of our general partner, which may lead to additional conflicts of interest. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner s fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without those limitations, might constitute breaches of fiduciary duty.

Our general partner will not be in breach of its obligations under our partnership agreement or its duties to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- approved by the vote of the holders of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If the resolution or course of action taken with respect to the conflict of interest satisfies any of the standards set forth in the first, third or fourth bullet points above, then such resolution or course of action will be deemed to be approved by all of our unitholders and, in the case of all four bullet points above, will not constitute a breach of our partnership agreement or of any duties our general partner may owe us or our unitholders.

As required by our partnership agreement, the board of directors of our general partner will maintain a conflicts committee comprised of at least two independent directors. Our general partner may, but is not required to, seek approval from the conflicts committee of a resolution of a conflict of interest with our general partner or affiliates. Any matters approved by the conflicts committee will be conclusively deemed to have been approved in good faith. If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third or fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith and, in each case, in any proceeding brought by or on behalf of any limited partner or us challenging such approval, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to subjectively believe that he or she is acting in our best interest.

Affiliates of our general partner are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner (or as general partner or managing member, as the case may be, of another company of which we are a partner or member) or those activities incidental to its ownership of interests in us. However, affiliates of our general partner, including the Mid-Con Affiliates, and Yorktown are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Additionally, Yorktown, through its investment funds and managed accounts, makes investments and purchases entities in various areas of the oil and natural industry. These investments and acquisitions may include entities or assets that we would have been interested in acquiring.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner, any of its affiliates (including its executive officers, directors and the Mid-Con Affiliates) or Yorktown. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us; provided, however, that such person does not pursue or acquire such opportunity for itself as a result of using confidential or proprietary information provided by or on behalf of us to such person. Therefore, affiliates of our general partner, including the Mid-Con Affiliates, and Yorktown may compete with us for investment opportunities and may own an interest in entities that compete with us.

Our general partner and its affiliates are allowed to take into account the interests of parties other than us in resolving conflicts of interest.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include our general partners limited call right, its registration rights and its determination whether or not to consent to any merger or consolidation involving us.

All of the executive officers and non-independent directors of our general partner spend significant time serving entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

To maintain and increase our levels of production, we will need to acquire oil and natural gas properties. All of the executive officers and non-independent directors of our general partner are also officers and/or directors of the Mid-Con Affiliates and devote significant time to those businesses. Further, all of our executive officers and non-independent directors have economic interests in, as well as management and fiduciary duties to, the Mid-Con Affiliates. The existing positions held by these directors and officers may give rise to fiduciary duties that are in conflict with fiduciary duties they owe to us. We cannot assure our unitholders that these conflicts will be resolved in our favor. As officers and directors of our general partner, these individuals may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may become affiliated. Due to

these existing and potential future affiliations and economic interests in these and other entities, they may have fiduciary obligations or incentives to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present them to us. For further discussion of our management s business affiliations and the potential conflicts of interest of which our unitholders should be aware, please read Business and Properties Our Principal Business Relationships and Management.

Our partnership agreement limits our general partner s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, which allows our general partner to consider only the interests and factors that it desires, without a duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns, the exercise of its registration rights and its determination whether or not to consent to any merger or consolidation involving us or to any amendment to the partnership agreement;

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must either be (i) on terms no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) must be fair and reasonable to us, as determined by our general partner in good faith. In determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us;

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal;

- provides that in resolving conflicts of interest, it will be presumed that in making its decision our general partner s board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

- provides that in resolving conflicts of interest, it will be conclusively deemed that in making its decision the conflicts committee of our general partner s board of directors acted in good faith.

By purchasing a common unit, a unitholder will become bound by the provisions in the partnership agreement, including the provisions discussed above. Please read Fiduciary Duties.

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Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought conflicts committee approval, on such terms as it determines to be necessary or appropriate to conduct our business, including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible or exchangeable into our securities, and the incurring of any other obligations;
- the purchase, sale or other acquisition or disposition of our securities, or the issuance of options, rights, warrants, restricted units, unit appreciation rights, phantom or tracking interests or other economic interests in us or relating to our securities;
- the acquisition, disposition, mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets or the merger or other combination of us with or into another entity (subject to certain prior approvals);
- the use of our assets (including cash on hand) for any purpose consistent with our partnership agreement;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of our cash;
- the selection, employment, retention and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;
- the maintenance of insurance for our benefit and the benefit of our partners;
- the formation of, or acquisition of an interest in, the contribution of property to, and the making of loans to, any limited or general partnerships, joint ventures, corporations, limited liability companies or other entities;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the making of tax, regulatory and other filings or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets; and

the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Our partnership agreement provides that our general partner must act in good faith when making decisions on our behalf, and our partnership agreement further provides that in order for a determination by our general partner to be made in good faith, our general partner must subjectively believe that the determination is in our best interests. Please read The Partnership Agreement Limited Voting Rights for information regarding matters that require unitholder approval.

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Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership interests and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- the manner in which our business is operated;
- the amount, nature and timing of asset purchases and sales, including whether to pursue acquisitions that may also be suitable for affiliates of our general partner;
- the amount, nature and timing of our capital expenditures;
- the amount of borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

Our partnership agreement provides that we and our subsidiary may borrow funds from our general partner and its affiliates. However, our general partner and its affiliates may not borrow funds from us or our operating subsidiaries.

Our general partner determines which costs incurred by it are reimbursable by us.

We reimburse our general partner and its affiliates for costs incurred in managing and operating our business, including costs incurred in rendering staff and support services to us pursuant to the services agreement with our affiliate Mid-Con Energy Operating.

Payments for these services can be substantial and will reduce the amount of cash available for distribution to our unitholders. Please read Certain Relationships and Related Party Transactions Services Agreement. Our general partner has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us. In turn, our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Please read Certain Relationships and Related Party Transactions.

In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, will not be the result of arm s-length negotiations.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts, and arrangements between us and our general partner and its affiliates are the result of arm s-length negotiations, and in the future some such agreement, contracts or arrangements may not be the result of arm s-length negotiations. Similarly, agreements, contracts or arrangements between us and our general partner and its affiliates that are entered into following the closing

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of this offering will not be required to be negotiated on an arm s-length basis, although, in some circumstances, our general partner may determine that the conflicts committee may make a determination on our behalf with respect to such arrangements.

Our general partner will determine, in good faith, the terms of any of these transactions entered into after the close of this offering.

Our general partner and its affiliates have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically for such use. There is no obligation of our general partner and its affiliates to enter into any contracts of this kind.

Our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner may exercise its right to call and purchase common units as provided in the partnership agreement or assign this right to one of its affiliates or to us. Our general partner is not bound by fiduciary duty restrictions in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read The Partnership Agreement Limited Call Right.

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us, on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Our general partner has limited its liability regarding our obligations.

Our general partner has and will enter into contractual arrangements on our behalf and has and will limit its liability under such contractual arrangements so that the other party has recourse only to our assets and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The attorneys, independent accountants and others who have performed services for us regarding this offering have been retained by our general partner. The attorneys, independent accountants and others who perform services for us are selected by our general partner, or the conflicts committee of our general partner s board of directors, and may also perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

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Fiduciary Duties

Our general partner is accountable to us and our unitholders as a fiduciary. Fiduciary duties owed to unitholders by our general partner are prescribed by law and the partnership agreement. The Delaware Revised Uniform Limited Partnership Act, which we refer to in this prospectus as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, modify, restrict or expand the fiduciary duties otherwise owed by a general partner to limited partners and the partnership.

Our partnership agreement contains various provisions modifying and restricting the fiduciary duties that might otherwise be owed by our general partner. We have adopted these restrictions to allow our general partner and its affiliates to engage in transactions with us that would otherwise be prohibited by state-law fiduciary duty standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. Without these modifications, our general partner s ability to make decisions involving conflicts of interest would be restricted, and engaging in such transactions could result in violations of our general partner s state-law fiduciary standards. We believe these modifications are appropriate and necessary because our general partner s board of directors has fiduciary duties to manage our general partner in a manner beneficial to its owners, as well as to our unitholders. The modifications to the fiduciary standards enable our general partner to take into consideration the interests of all parties involved in the proposed action, so long as the resolution is fair and reasonable to us. These modifications also enable our general partner to attract and retain experienced and capable directors. These modifications are detrimental to our common unitholders because they restrict the rights and remedies that would otherwise be available to our unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest.

The following is a summary of the material restrictions of the fiduciary duties owed by our general partner to the limited partners:

State-law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present.
Rights and remedies of unitholders	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These legal actions include actions against a general partner for breach of fiduciary duty or the partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

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Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues about compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in good faith and will not be subject to any other standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These standards reduce the obligations to which our general partner would otherwise be held.

In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for losses sustained or liabilities incurred as a result of any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct, or in the case of a criminal matter, acted with the knowledge that such conduct was unlawful.

Special Provisions Regarding Affiliated Transactions. Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest that are not approved by a vote of unitholders and that are not approved by the conflicts committee of the board of directors of our general partner must be:

- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

- fair and reasonable to us, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us).

If our general partner does not seek approval from the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the bullet points above, then it will be presumed that, in making its decision, the board of directors, which may include board members affected by the conflict of interest, acted in good

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faith, and in any proceeding brought by or on behalf of any limited partner or us challenging such approval, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards reduce the obligations to which our general partner would otherwise be held.

By purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign a partnership agreement does not render our partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and its officers, directors, managers and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that, in respect of the matter for which these persons are seeking indemnification, these persons acted in bad faith or engaged in fraud or willful misconduct. We must also provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act of 1933, in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please read The Partnership Agreement Indemnification.

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PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO

CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions. The information presented in this section assumes that our general partner will continue to make capital contributions to us in order to maintain its approximate 2.0% general partner interest.

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 days after the end of each quarter, we will distribute all of our available cash to unitholders of record on the applicable record date. We will distribute approximately 98.0% of our available cash to our common unitholders, pro rata, and approximately 2.0% to our general partner. Unlike many publicly traded limited partnerships, our general partner is not entitled to any incentive distributions, and we do not have any subordinated units.

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 law or any of our loan agreements, security agreements, mortgages, debt instruments or other agreements or obligations; or

- provide funds for 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 the cash and cash equivalents on hand on the date of determination of available cash for the quarter.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors and the liquidator in the order of priority provided in our partnership agreement and by law. Thereafter, we will distribute any remaining proceeds to our unitholders and our general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in the partnership agreement. Upon our liquidation, we will allocate any net gain (or unrealized gain attributable to assets distributed in kind to our partners) in the following manner:

first, to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances; and

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second, approximately 98.0% to the common unitholders, pro rata, and approximately 2.0% to our general partner.

Manner of Adjustments for Losses

Upon our liquidation, we will generally allocate any loss to our general partner and the unitholders in the following manner:

- *first*, approximately 98.0% to the holders of common units, in proportion to the positive balances in their capital accounts and approximately 2.0% to our general partner, until the capital accounts of our unitholders have been reduced to zero; and

- *thereafter*, 100% to our general partner.

Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for U.S. federal income tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and our general partner in the same manner as we allocate gain or loss upon liquidation.

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DESCRIPTION OF THE COMMON UNITS

The Units

Our common units are traded on the NASDAQ Global Market under the symbol MCEP. At the close of business on October 11, 2012, based upon information received from our transfer agent and brokers and nominees, we had approximately 25 unrestricted common unitholders of record. This number does not include owners for whom common units may be held in street name or whose common units are restricted. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the rights of holders of common units in and to partnership distributions, please read this section and Provisions of Our Partnership Agreement Relating to Cash Distributions. For a description of other rights and privileges of limited partners under our partnership agreement, including voting rights, please read The Partnership Agreement.

Transfer Agent and Registrar

Duties

Wells Fargo Shareowner Services serves as registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units, except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates or to cover taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There is no charge to our unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their respective stockholders, directors, officers and employees against all claims and losses that may arise out of their actions for their activities in that capacity, except for any liability due to any gross negligence or willful misconduct of the indemnitee.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of our partnership agreement; and
- makes the consents, acknowledgments and waivers contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with this offering.

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Our general partner may request that a transferee of common units certify that such transferee is an Eligible Holder. As of the date of this prospectus, an 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 of the United States, including a municipality of the United States;
- 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.

For the avoidance of doubt, 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.

In addition to other rights acquired upon transfer, the transferor gives the transferee the right to be admitted to our partnership as a limited partner with respect to the transferred common units. A transferee will become a limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder s rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and any transfers are subject to the laws governing transfers of securities.

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THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read Provisions of Our Partnership Agreement Relating to Cash Distributions;
- with regard to the fiduciary duties of our general partner, please read Conflicts of Interest and Fiduciary Duties;
- with regard to the transfer of common units, please read Description of the Common Units Transfer Agent and Registrar Transfer of Common Units; and
- with regard to allocations of taxable income, taxable loss and other matters, please read Material Tax Consequences.

Organization and Duration

Our partnership was organized in July 2011 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under our partnership agreement is to engage directly in, or enter into or form, hold and dispose of any corporation, partnership, joint venture, limited liability company or other arrangement to engage directly in, any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law and, in connection therewith, to exercise all of the rights and powers conferred upon us pursuant to the agreements relating to such business activity and do anything necessary or appropriate to the foregoing. However, our general partner may not cause us to engage in any business activity that it determines would be reasonably likely to cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the ability to cause us and our subsidiary to engage in activities other than the ownership, acquisition, exploitation and development of oil and natural gas properties and the ownership, acquisition and operation of related assets, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners. Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Cash Distributions

Our partnership agreement specifies the manner in which we will make cash distributions to our unitholders and other partnership interests as well as to our general partner in respect of its general partner interest. For a description of these cash distribution provisions, please read Provisions of Our Partnership Agreement Relating to Cash Distributions.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described under Limited Liability.

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For a discussion of our general partner s right to contribute capital to maintain its approximate 2.0% general partner interest if we issue additional units, please read Issuance of Additional Interests.

Limited Voting Rights

The following is a summary of the unitholder vote required for each of the matters specified below.

Various matters require the approval of a unit majority, which means the approval of a majority of the outstanding common units.

In voting their common units, our general partner, and our general partner s affiliates (including the Founders) and Yorktown will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or our limited partners.

Issuance of additional units	No approval right. Please read Issuance of Additional Interests.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of any limited partner. Other amendments generally require the approval of a unit majority. Please read Amendment of the Partnership Agreement.
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority, in certain circumstances. Please read Merger, Consolidation, Sale or Other Disposition of Assets.
Dissolution of our partnership	Unit majority. Please read Dissolution.
Continuation of our business upon dissolution	Unit majority. Please read Dissolution.
Withdrawal of our general partner	Prior to December 31, 2021, under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates (including the Founders), is required for the withdrawal of our general partner in a manner that would cause a dissolution of our partnership. Please read Withdrawal or Removal of Our General Partner.
Removal of our general partner	Not less than $66^2/_3\%$ of the outstanding units, including units held by our general partner and its affiliates (including the Founders). Please read Withdrawal or Removal of Our General Partner.
Transfer of our general partner interest	Our general partner may transfer without a vote of our unitholders all, but not less than all, of its general partner interest in us to an affiliate or another person (other than an individual) in connection with its merger or consolidation with or into, or sale of all, or substantially all, of its assets to, such other person. The approval of a majority of the common units, excluding common units held by our general partner and its affiliates (including the Founders), is required in other circumstances for a transfer of the general partner

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	interest to a third party prior to December 31, 2021. Please read Transfer of General Partner Interest.
Transfer of ownership interests in our general partner	No approval required at any time. Please read Transfer of Ownership Interests in Our General Partner.

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of duty (including any fiduciary duty) owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to or to interpret or enforce any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court in the State of Delaware with subject matter jurisdiction), in each case, regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing a common unit, a limited partner (i) irrevocably submits to the exclusive jurisdiction of such courts in connection with any such claim, suit, action or proceedings; (ii) irrevocably agrees not to, and waives any right to, assert in any such claim, suit, action or proceeding that (A) it is not personally subject to the jurisdiction of such courts or of any other court to which proceedings in such courts may be appealed, (B) such claim, suit, action or proceeding is brought in an inconvenient forum, or (C) the venue of such claim, suit, action or proceeding is improper; (iii) expressly waives any requirement for the posting of a bond by a party bringing such claim, suit, action or proceeding; (v) consents to process being served in any such claim, suit, action or proceeding by (X) mailing, certified mail, return receipt requested, a copy thereof to such party at the address in effect for notices under our partnership agreement or (Y) any other manner permitted by law; and (vi) irrevocably waives any and all right to trial by jury in any such claim, suit, action or proceeding.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of our partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right or exercise of the right by our limited partners as a group:

- to remove or replace our g