Atlas Resource Partners, L.P.
Form 424B5
November 21, 2012

Table of Contents

As Filed Pursuant to Rule 424(b)(5)
Registration No. 333-180477

PROSPECTUS SUPPLEMENT

(To Prospectus dated April 13, 2012)

ATLAS RESOURCE PARTNERS, L.P.

7,600,000

COMMON UNITS REPRESENTING LIMITED PARTNER INTERESTS

We are offering to sell 7,600,000 of our common units representing limited partner interests.

Our common units are traded on the New York Stock Exchange (NYSE) under the symbol ARP. The last reported sales price of our common units on the NYSE on November 20, 2012 was $23.01.

	Per Common Unit	Total
Public Offering Price	$23.01	$174,876,000
Underwriting Discount	$0.9204	$6,995,040
Proceeds to Us (Before Expenses)	$22.0896	$167,880,960

We have granted the underwriters a 30-day option to purchase up to an additional 1,140,000 common units on the same terms and conditions set forth above to cover any over-allotments of common units, if any.

Investing in our common units involves certain risks. See Risk Factors on page S-7 of this prospectus supplement and on page 2 of the accompanying prospectus.

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

Joint Book-Running Managers

Wells Fargo Securities	**BofA Merrill Lynch**	**Citigroup**
Deutsche Bank Securities	**J.P. Morgan**	**Morgan Stanley**
	RBC Capital Markets	

Co-Managers

Baird	**Stifel Nicolaus Weisel**
Oppenheimer & Co.	**Wunderlich Securities**

The date of this prospectus supplement is November 20, 2012

Table of Contents

TABLE OF CONTENTS

PROSPECTUS SUPPLEMENT

ABOUT THIS PROSPECTUS SUPPLEMENT	S-ii
SPECIAL NOTE ON FORWARD-LOOKING STATEMENTS AND RISK FACTORS	S-ii
THE PARTNERSHIP	S-1
THE OFFERING	S-5
RISK FACTORS	S-7
USE OF PROCEEDS	S-9
CAPITALIZATION	S-10
U.S. FEDERAL INCOME TAX CONSIDERATIONS	S-11
UNDERWRITING; CONFLICTS OF INTEREST	S-17
LEGAL MATTERS	S-23
INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM	S-23
INDEPENDENT PETROLEUM ENGINEERS	S-23
WHERE YOU CAN FIND MORE INFORMATION	S-24

PROSPECTUS

ABOUT THIS PROSPECTUS	ii
SPECIAL NOTE ON FORWARD-LOOKING STATEMENTS AND RISK FACTORS	ii
THE COMPANY	1
RISK FACTORS	2
WHERE YOU CAN FIND MORE INFORMATION	2
USE OF PROCEEDS	3
RATIO OF EARNINGS TO FIXED CHARGES	3
GENERAL DESCRIPTION OF SECURITIES WE MAY OFFER	4
DESCRIPTION OF COMMON UNITS	4
DESCRIPTION OF PREFERRED UNITS	5
DESCRIPTION OF SUBORDINATED UNITS	6
DESCRIPTION OF DEBT SECURITIES	6
DESCRIPTION OF GUARANTEES OF DEBT SECURITIES	8
DESCRIPTION OF WARRANTS	8
OUR PARTNERSHIP AGREEMENT	10
OUR CASH DISTRIBUTION POLICY	23
TAX CONSIDERATIONS	37
PLAN OF DISTRIBUTION	52
LEGAL MATTERS	53
EXPERTS	53

In making your investment decision, you should rely only on the information contained or incorporated by reference in this prospectus supplement and the accompanying prospectus. We have not authorized any other person to provide you with any other information. If anyone provides you with different or inconsistent information, you should not rely on it.

You should not assume that the information contained in this prospectus supplement and the accompanying prospectus is accurate as of any date other than the date on the front cover of those documents. You should not assume that the information contained in the documents incorporated by reference in this prospectus supplement and the accompanying prospectus is accurate as of any date other than the respective dates of those documents. Our business, financial condition, results of operations and prospects may have changed since those dates. We will disclose any material changes

Table of Contents

in our affairs in an amendment to this prospectus, a prospectus supplement or a future filing with the Securities and Exchange Commission (the SEC) incorporated by reference in this prospectus.

ABOUT THIS PROSPECTUS SUPPLEMENT

This document is in two parts. The first part is this prospectus supplement, which adds to and updates information contained in the accompanying prospectus and the documents incorporated by reference into the accompanying prospectus. The second part is the accompanying prospectus, which gives more general information, some of which may not apply to this offering.

To the extent any inconsistency or conflict exists between (i) the information included in or incorporated by reference into this prospectus supplement, and (ii) the information included in or incorporated by reference into the accompanying prospectus, the information included in or incorporated by reference into this prospectus supplement updates and supersedes the information included in or incorporated by reference into the accompanying prospectus. In addition, any statement in a filing that we make with the SEC that adds to, updates or changes information contained in an earlier filing that we made with the SEC shall be deemed to modify and supersede such information in the earlier filing.

SPECIAL NOTE ON FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Certain sections of this prospectus supplement and the accompanying prospectus contain statements reflecting our views about our future performance and constitute forward-looking statements. We and our representatives may, from time to time, make written or oral forward-looking statements, including statements contained in our filings with the SEC and in our reports to security holders. Generally, the inclusion of the words believe, expect, intend, estimate, project, anticipate, will and similar expressions identify statements that consti forward-looking statements. All statements addressing operating performance of us or any subsidiary, events or developments that we expect or anticipates would occur in the future are forward-looking statements.

These views involve risks and uncertainties that are difficult to predict and, accordingly, our actual results may differ materially from the results discussed in such forward-looking statements. Readers should consider the various factors, including those discussed in our annual report for the year ended December 31, 2011 under Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and Critical Accounting Policies and Estimates, as well as the Risk Factors section of our quarterly report on Form 10-Q for the quarter ended September 30, 2012, on file with the SEC for additional factors that may affect our performance. The forward-looking statements are and will be based upon management s then-current views and assumptions regarding future events and operating performance, and are applicable only as of the dates of such statements. We undertake no obligation to update any forward-looking statements as a result of new information, future events or otherwise.

Table of Contents

THE PARTNERSHIP

We are a publicly-traded master limited partnership (NYSE: ARP) and an independent developer and producer of natural gas and oil, with operations in basins across the United States. We are a leading sponsor and manager of tax-advantaged investment partnerships, in which we co-invest, to finance a portion of our natural gas and oil production activities. We believe we have established a strong track record of growing our reserves, production and cash flows through a balanced mix of natural gas and oil exploitation and development and sponsorship of investment partnerships and acquisition of oil and gas properties. Our primary business objective is to generate growing yet stable cash flows allowing us to make increasing cash distributions to our unitholders through the acquisition and development of mature, long-lived natural gas and oil properties. As of September 30, 2012, we own production positions in the following areas:

- the Appalachia basin, including the Marcellus Shale, the Utica Shale, and the Chattanooga Shale in northeastern Tennessee. We have ownership interests in over 9,800 wells in the Appalachian basin, including over 225 wells in the Marcellus Shale;
- the Barnett Shale in the Bend Arch Fort Worth Basin in northern Texas, in which we established a position following our acquisitions of assets from Carrizo and Titan during 2012. We have ownership interests in over 265 wells in the Barnett Shale;
- the Mississippi Lime play in northwestern Oklahoma, in which we established a position through transactions with Equal Energy, Ltd. during 2012;
- the Niobrara Shale in northeastern Colorado;
- the New Albany Shale in southwestern Indiana; and
- the Antrim Shale in Michigan.

We believe we have created substantial value by executing our strategy of acquiring properties with stable, long-life production, relatively predictable decline curves and lower risk development opportunities. Overall, we have acquired significant net proved reserves and approximately 62 Mmcfed of production in the third quarter of 2012 through the following transactions:

- *Carrizo Barnett Shale Assets* On April 30, 2012, we acquired assets in the core of the Barnett Shale from Carrizo Oil & Gas, Inc. (NASD: CRZO), which we refer to as Carrizo, for approximately $190 million, which was funded through the private placement of $120 million of equity and $70 million of borrowings under our revolving credit facility. The assets include 198 gross producing wells generating approximately 31 Mmcfed of production at the effective date of acquisition on over 12,000 net acres, all of which are held by production. We hedged 100% of available production acquired for the first twelve months after the acquisition date, and between 40% to 80% of anticipated proved developed production for the subsequent four years, mitigating commodity exposure and enhancing acquisition economics.
- *Titan Barnett Shale Assets* On July 26, 2012, we acquired Titan Operating, L.L.C., which we refer to as Titan, which owned assets in the Barnett Shale on approximately 16,000 net acres, which are 90% held by production, for approximately 3.8 million of our common units and approximately 3.8 million of our Class B convertible preferred units (which had a collective value of $193.2 million based upon the closing price of our publicly-traded common units as of the acquisition closing date) and approximately $15.4 million in cash for closing adjustments. Titan s assets are located in close proximity to the assets acquired from Carrizo in the Barnett Shale. Net production from these assets at the effective date of acquisition was approximately 24 Mmcfed, including approximately 370 Bpd

of natural gas liquids. We hedged 100% of available production acquired through June 2013, and between 40% and 80% of anticipated proved developed production for the subsequent four years, mitigating commodity exposure and enhancing acquisition economics. We believe there are approximately 335 potential undeveloped drilling locations on the Titan acreage.

Equal Mississippi Lime Assets On April 4, 2012, we entered into an agreement with Equal Energy, Ltd. (NYSE: EQU; TSX: EQU), which we refer to as Equal, to acquire a 50% interest in Equal s approximately 14,500 net undeveloped acres in the core of the oil and liquids rich Mississippi Lime play in northwestern Oklahoma for approximately $18 million. On September 24, 2012, we acquired Equal s remaining 50% interest in approximately 8,500 net undeveloped acres included in the joint venture, approximately 8 Mmcfed of net production in the region at the effective date of acquisition and substantial salt water disposal infrastructure for approximately $40 million. Both transactions were financed through borrowings under our revolving credit facility. The transaction increases our position in the Mississippi Lime play to 19,800 net acres in Alfalfa, Grant and Garfield counties in Oklahoma.

In addition to our acquisition strategy, we have targeted certain high-returning plays, including the Marcellus Shale in northeastern Pennsylvania and the Utica Shale in eastern Ohio, for organic leasing efforts and development. In the Marcellus Shale, we have leased acreage in Lycoming County in northeast Pennsylvania, a highly desirable and productive dry gas area, where we have completed three pad sites that will each accommodate multiple horizontal wells, of which four wells are in various stages of drilling as of September 30, 2012. We also have prospective Utica Shale acreage in Harrison, Tuscarawas, and Stark counties, highly desirable areas which have experienced escalated permitting and drilling activity, where we have 5 horizontal wells in Harrison County in various stages of drilling as of September 30, 2012. We currently have interests in over 2,500 wells in Ohio and operate three field offices, which we intend to use to manage future Utica Shale development. These development opportunities, coupled with the undeveloped drilling opportunities on our acreage in the Barnett Shale and the Mississippi Lime, could potentially provide us with approximately $2.0 billion of total potential capital investments in future periods.

We were formed in October 2011 to own and operate substantially all of the Atlas Energy E&P Operations, which were transferred to us on March 5, 2012 by Atlas Energy (NYSE: ATLS), a publicly-traded master limited partnership which owns 100% of our general partner Class A units and incentive distribution rights and an approximate 51.5% limited partnership interest (20,960,000 limited partner units) in us before giving effect to this offering.

Business Strategy

The key elements of our business strategy are:

Expand our natural gas and oil production. We generate a significant portion of our revenue and net cash flow from natural gas and oil production. We believe our strategy of increasing our natural gas and oil production through our sponsorship of investment partnerships as well as drilling wells directly to exploit our acreage opportunities provides us with enhanced economic returns. For the five year period ended December 31, 2011, we raised over $1.4 billion from outside investors through our investment partnerships. We intend to continue to develop our inventory of proved undeveloped locations through both sponsorship of investment partnerships and direct well drilling to add value through reserve and production growth.

Expand our fee-based revenue through our sponsorship of investment partnerships. We generate substantial revenue and cash flow from fees paid by the investment partnerships to us for acting as the managing general partner. As we continue to sponsor investment partnerships, we expect that our fee revenues from our drilling and operating agreements with our investment partnerships will increase. We

expect that the fee revenue we generate with respect to fees paid by the investment partnerships to us for partnership management will add stability to our revenue and cash flows. Furthermore, the carried interests and fees we earn reduce the net investment in our drilling program and therefore enhance our rates of return on investment.

Expand operations through strategic acquisitions. We continually evaluate opportunities to expand our operations through acquisitions of developed and undeveloped properties or companies that will generate attractive risk adjusted expected rates of return and increase our cash available for distribution. Our acquisitions have been characterized by long-lived production, relatively low decline rates and predictable production profiles, as well as relatively low-risk development opportunities. We will continue to seek strategic opportunities in our current areas of operation, as well as other regions of the United States.

Continue to maintain control of operations and costs. We believe it is important to be the operator of wells in which we or our investment partnerships have an interest because we believe it will allow us to achieve operating efficiencies and control costs. As operator, we are better positioned to control the timing and plans for future enhancement and exploitation efforts, costs of enhancing, drilling, completing and producing the well, and marketing negotiations for our natural gas and oil production to maximize both volumes and wellhead price. We were the operator of the vast majority of the properties in which we or our investment partnerships had a working interest at September 30, 2012.

Continue to manage our exposure to commodity price risk. To limit our exposure to changing commodity prices and enhance and stabilize our cash flow, we use financial hedges for a portion of our natural gas and oil production. We principally use fixed price swaps and collars as the mechanism for the financial hedging of our commodity prices.

Competitive Strengths

We believe we are well-positioned to successfully to execute our business strategy because of the following competitive strengths:

We have a high quality, long-lived reserve base. Our natural gas properties are located principally in the Appalachian Basin and the Barnett Shale, and are characterized by long-lived reserves, favorable pricing for our production and readily available transportation. Moreover, because our production in the Appalachian Basin is located near markets in the northeast United States, we believe we will generally receive a premium over quoted prices on the NYMEX for the natural gas we produce.

Our partnership management business can improve the economic rates of return associated with our natural gas and oil production activities. A well drilled, net to our equity interest, in our partnership management business will provide us with an enhanced rate of return. For each well drilled in a partnership, we receive an upfront fees on the investors well construction and completion costs and a fixed administration and oversight fee. Further, we receive an incremental equity interest in each well, for which we do not make any corresponding capital contribution. Consequently, our economic interest in each well is significantly greater than our proportional contribution to the total cash costs which enhances our overall rate of return. Additionally, we receive monthly per well fees from the partnership for the life of each individual well, which also increases our rate of return.

Fee-based revenues from our investment partnerships provide a stable foundation for our distributions. Our investment partnerships provide us with stable, fee-based revenues which diminish the influence of commodity price fluctuations on our cash flows. Our fees for managing our investment partnerships accounted for approximately 41% of our segment margin for the year ended December 31, 2011. In addition, because our investment partnerships reimburse us on a cost-plus basis for drilling capital expenses, we are partially protected against increases in drilling costs.

Table of Contents

We are one of the leading sponsors of tax-advantaged investment partnerships. We and our predecessor have sponsored limited and general partnerships to raise funds from investors to finance our development drilling activities since 1968, and we believe that we are one of the leading sponsors of such investment partnerships in the country. We believe that our lengthy association with many of the broker-dealers that act as placement agents for our investment partnerships provide us with a competitive advantage over entities with similar operations. We also believe that our sponsorship of investment partnerships has allowed us to generate attractive returns on drilling, operating and production activities.

We have significant experience in making accretive acquisitions. Our management team has extensive experience in consummating accretive acquisitions. We believe we will be able to generate acquisition opportunities of both producing and non-producing properties through our management s extensive industry relationships. We intend to use these relationships and experience to find, evaluate and execute on acquisition opportunities.

We have significant engineering, geologic and management experience. Our technical team of geologists and engineers has extensive industry experience. We believe that we have been one of the most active drillers in our core operating areas and, as a result, that we have accumulated extensive geological and geographical knowledge about the area. We have added geologists and engineers to our technical staff that have significant experience in other productive basins within the continental United States, which will allow us to evaluate and possibly expand our core operating areas.

Recent Developments

On November 19, 2012, we announced the execution of a definitive agreement with DTE Gas Resources, LLC, a wholly-owned subsidiary of DTE Energy Company (NYSE: DTE), to purchase Fort Worth Basin oil and natural gas properties for $255 million in cash, subject to customary purchase price adjustments. The properties to be acquired include an estimated 35 MMBoe (210 Bcfe) of proved reserves, 31% of which are proved developed and 24% of which are oil. Average 2012 net production is approximately 3,800 Boe/d from approximately 261 gross producing wells on over 88,000 net acres located primarily in Jack, Erath, Palo Pinto and Clay Counties. The acreage position includes approximately 75,000 net acres prospective for the oil and NGL-rich Marble Falls play, in which there are over 700 identified vertical drilling locations. We believe that there are further potential development opportunities through vertical down-spacing and horizontal drilling in the Marble Falls formation, in which we expect to commence drilling operations by early 2013. Closing of the pending transaction is expected to occur in December 2012 with an effective date of October 1, 2012, and is subject to customary closing conditions.

The information presented above is based solely on our internal evaluation and interpretation of reserve and other information provided to us in the course of our due diligence with respect to the pending transaction and has not been independently verified or estimated.

Upon completion of this offering and the application of the net proceeds therefrom to fund a portion of the purchase price of the pending transaction, we expect that the remaining portion of the purchase price will be funded with borrowings under our revolving credit facility or, subject to market conditions, proceeds from the issuance of private or public equity securities.

Table of Contents

THE OFFERING

Common units offered	7,600,000 common units.
	8,740,000 common units if the underwriters exercise their option to acquire an additional 1,140,000 common units.
Units outstanding before this offering	36,074,908 common units.
Units outstanding after this offering	43,674,908 common units, or 44,814,908 common units if the underwriters exercise their option to acquire an additional 1,140,000 common units.
Use of proceeds	We plan to use all of the net proceeds from this offering to fund a portion of the $255 million purchase price of the pending Fort Worth Basin acquisition. Before funding the pending Fort Worth Basin acquisition, we may use some or all of the net proceeds for general partnership purposes, which may include repayment of outstanding borrowings under our revolving credit facility. See Use of Proceeds.
Cash distribution policy	We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner in its discretion. The amount of this cash may be greater than or less than the minimum quarterly distribution referred to in the next paragraph. Our partnership agreement requires us to make cash distributions within 45 days after the end of each quarter.
	When quarterly cash distributions exceed $0.46 per unit in any quarter, our general partner, as the holder of our class A units, receives a higher percentage of the cash distributed in excess of that amount, in increasing percentages up to 50% if the quarterly cash distribution exceeds $0.60 per unit. We refer to our general partner s right to receive these higher amounts of cash as incentive distribution rights.
	For a discussion of our cash distribution policy, please read Our Cash Distribution Policy in the accompanying prospectus.
	On October 25, 2012, we declared a quarterly cash distribution of $0.43 per common unit for the quarter ended September 30, 2012, to holders of record as of November 5, 2012. Purchasers in this offering will not be entitled to participate in this distribution.
Voting rights	Our common unitholders have only limited voting rights of matters affecting our business. Common unitholders do not elect our general partner or the members of its board of directors. The board of directors of our general partner is chosen by Atlas Energy.

Estimated ratio of taxable income to distributions	We estimate that a purchaser of common units in this offering who holds those common units from the date of the closing of this offering through the record date for distributions for the quarter ending December 31, 2015 will be allocated, on a

Table of Contents

	cumulative basis, an amount of federal taxable income for that period that will be less than 10% of the cash distributed with respect to that period. Please read U.S. Federal Income Tax Considerations in this prospectus supplement.
Tax consequences	The U. S. federal income tax consequences of owning and disposing of our common units are summarized under the heading U.S. Federal Income Tax Consequences in this prospectus supplement and under the heading Tax Considerations in the accompanying prospectus.
New York Stock Exchange symbol	ARP.
Risk factors	You should read Risk Factors on page S-7 of this prospectus supplement and in the documents incorporated herein by reference, as well as the other cautionary statements throughout this prospectus supplement, to ensure you understand the risks associated with an investment in our common units.
Conflicts of Interest	Affiliates of Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Deutsche Bank Securities Inc. and J.P. Morgan Securities LLC are agents and lenders under our revolving credit facility and may receive a substantial portion of the proceeds of this offering through the repayment of indebtedness under such facility. See Underwriting; Conflicts of Interest.

Table of Contents

RISK FACTORS

Investing in our common units involves risk. Before you decide whether to purchase any of our common units, in addition to the other information, documents or reports included or incorporated by reference into this prospectus supplement and the accompanying prospectus or other offering materials, you should carefully consider the following risk factors and the risk factors in the section entitled Risk Factors in our most recent Annual Report on Form 10-K and any Quarterly Reports on Form 10-Q and Current Reports on Form 8-K filed by us subsequent to such Annual Report on Form 10-K, as the same may be amended, supplemented or superseded from time to time by our filings under the Securities Exchange Act of 1934, as amended, or the Exchange Act. For more information, see the section of this prospectus supplement entitled Where You Can Find More Information. These risks could materially and adversely affect our business, financial condition or operating results and could result in a partial or complete loss of your investment.

We may not be able to consummate our pending Fort Worth Basin acquisition.

The purchase agreement related to the pending Fort Worth Basin acquisition contains customary closing conditions. It is possible that one or more closing conditions may not be satisfied or, if not satisfied, that such condition may not be waived by the other party. The closing of this offering is not contingent upon the closing of the pending Fort Worth Basin acquisition. Accordingly, if you decide to purchase our units, you should be willing to do so whether or not we complete the pending Fort Worth Basin acquisition.

Any acquisitions we complete, including the pending Fort Worth Basin acquisition, are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

Any acquisition, including the pending Fort Worth Basin acquisition, involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility 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 environmental and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management s attention from other business concerns;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- the loss of key purchasers of our production.

Our decision to acquire oil and natural gas properties depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

Table of Contents

Our 2012 acquisitions and our pending Fort Worth Basin acquisition may prove to be worth less than we paid, or provide less than anticipated proved reserves, because of uncertainties in evaluating recoverable reserves, well performance, and potential liabilities as well as uncertainties in forecasting oil and natural gas prices and future development, production and marketing costs.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, development potential, well performance, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Our estimates of future reserves and estimates of future production for our 2012 acquisitions, including the pending Fort Worth Basin acquisition, are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting independent petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain; our proved reserves estimates may thus exceed actual acquired proved reserves. In connection with our assessments, we perform a review of the acquired properties included in the 2012 acquisitions and the pending Fort Worth Basin acquisition that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of the properties included in the 2012 acquisitions and the pending Fort Worth Basin acquisition are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given the time constraints imposed by the applicable acquisition agreement. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential.

Table of Contents

USE OF PROCEEDS

We expect to receive net proceeds of approximately $167.7 million from this offering, after the underwriters discounts and estimated offering fees and expenses payable by us. If the underwriters exercise their option to purchase 1,140,000 additional common units in full, the net proceeds, after deducting underwriters discounts and estimated offering fees and expenses, will be approximately $192.9 million. We plan to use all of the net proceeds from this offering to fund a portion of the $255 million purchase price of the pending Fort Worth Basin acquisition. Please read Summary Recent Developments for a description of the pending acquisition. Before funding the pending Fort Worth Basin acquisition, we may use some or all of the net proceeds for general partnership purposes, which may include repayment of outstanding borrowings under our revolving credit facility. We expect to fund the remaining portion of the purchase price for the pending Fort Worth Basin acquisition with borrowings under our revolving credit facility or proceeds from the issuance of private or public equity securities, pending market conditions.

The closing of this offering is not contingent upon the closing of the pending Fort Worth Basin acquisition. Accordingly, if you decide to purchase our units, you should be willing to do so whether or not we complete the pending Fort Worth Basin acquisition. If we do not complete the pending Fort Worth Basin acquisition, we will use the net proceeds from the offering to reduce borrowings outstanding under our revolving credit facility, for general partnership purposes and for potential future acquisitions.

Affiliates of Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Deutsche Bank Securities Inc. and J.P. Morgan Securities LLC in this offering are lenders under our revolving credit facility and may receive a substantial portion of the proceeds from this offering. See Underwriting. As of November 19, 2012, indebtedness outstanding under our revolving credit facility was approximately $264.0 million at a weighted average interest rate of 3.6%, excluding outstanding letters of credit. In addition to working capital and general partnership purposes, we borrowed from time to time under our revolving credit facility for capital expenditures and to finance our asset acquisitions. The revolving credit facility matures in March 2016.

Table of Contents

CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2012 (i) on an actual basis, and (ii) on an adjusted basis to give effect to this offering and the application of the net proceeds therefrom, as described in Use of Proceeds.

You should read the following table in conjunction with our historical consolidated financial statements and related notes, Management s Discussion and Analysis of Financial Condition and Results of Operations and other financial information included elsewhere or incorporated by reference in this prospectus supplement.

	As of September 30, 2012	
	Actual	**As adjusted**
	(in thousands)	
Cash and cash equivalents	$ 24,266	$ 24,266
Debt:		
Credit facility[(1)]	222,000	54,319
Total debt	222,000	54,319
Partners capital:		
General partner s interest	7,646	7,646
Preferred limited partners interests	96,110	96,110
Common limited partners interests	596,348	764,029
Accumulated other comprehensive income	8,644	8,644
Total partners capital	708,748	876,429
Total capitalization	$ 930,748	$ 930,748

(1) As of November 19, 2012, indebtedness outstanding under our revolving credit facility was approximately $264.0 million. Pending the use of the net proceeds to fund a portion of the purchase price for the pending Fort Worth Basin acquisition, we may use some or all of the net proceeds for general partnership purposes, which may include repayment of outstanding borrowings under our revolving credit facility.

U.S. FEDERAL INCOME TAX CONSIDERATIONS

The tax consequences to you of an investment in our common units will depend in part on your own tax circumstances. For a discussion of the principal federal income tax considerations associated with our operations and the purchase, ownership and disposition of our common units, please read Tax Considerations beginning on page 30 in the accompanying prospectus. You are urged to consult with your own tax advisor about the federal, state, local and foreign tax consequences particular to your circumstances.

Ratio of Taxable Income to Distributions

We estimate that a purchaser of common units in this offering who holds those common units from the date of the closing of this offering through the record date for distributions for the quarter ending December 31, 2015 will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than 10% of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders will increase.

Our estimate is based upon the assumption that our available cash for distribution will be sufficient for us to make quarterly distributions at current or higher levels to the holders of our common units, and other assumptions with respect to capital expenditures, cash flow, net working capital and anticipated cash distributions. This estimate and the assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control. Further, our estimate is based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that our estimate will prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be greater, and perhaps substantially greater, than our estimate with respect to the period described above if (i) gross income from operations exceeds the amount required to make minimum quarterly distributions on all units, yet we only distribute the minimum quarterly distributions on all units; (ii) we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering; (iii) we drill fewer well locations than we anticipate or spend less than we anticipate in connection with our drilling and completion activities contemplated in our capital budget; or (iv) legislation is enacted that limits or repeals certain U.S. federal income tax preferences currently available to oil and gas exploration and production companies (please read Oil and Natural Gas Taxation Recent Legislative Developments in this prospectus supplement).

Tax Exempt Organizations and Other Investors

Ownership of common units by tax-exempt entities and foreign investors raises issues unique to such persons. Please read Tax Considerations Tax-Exempt Organizations and Other Investors beginning on page 38 of the accompanying base prospectus.

Tax Rates

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 35% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than 12 months) of individuals is 15%. However, absent new legislation extending the current rates, beginning January 1, 2013, the highest

Table of Contents

marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively and, further, in the absence of legislation extending the term of the preferential tax rates for qualified dividend income, taxpayers dividend income will be taxed at rates applicable to ordinary income for tax years beginning on or after January 1, 2013. Moreover, these rates are subject to change by new legislation at any time.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(1) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(2) a statement regarding whether the beneficial owner is:

  (a) a non-U.S. person;

  (b) a non-U.S. government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

  (c) a tax-exempt entity;

(3) the amount and description of units held, acquired or transferred for the beneficial owner; and

(4) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $100 per failure, up to a maximum of $1.5 million per calendar year, is imposed by the Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Oil and Natural Gas Taxation

Depletion Deductions

Subject to the limitations on deductibility of losses (please read Tax Considerations Tax Consequences of Unit Ownership Limitations on Deductibility of Our Losses in the accompanying prospectus), unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and natural gas interests. Although the Internal Revenue Code requires each unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our unitholders with information relating to this computation for federal income tax purposes. Each unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the underlying property for depletion and other purposes.

Percentage depletion is generally available with respect to unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Internal Revenue Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative contracts or the operation of a major refinery. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the unitholder s gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable

income of the unitholder from the property for each taxable year, computed without the depletion allowance. A unitholder

that qualifies as an independent producer may deduct percentage depletion only to the extent the unitholder s average net daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000-barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a unitholder s total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the unitholder s total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

Unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the unitholder s share of the adjusted tax basis in the underlying mineral property by the number of mineral units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the unitholder s share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the unitholder of some or all of his units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the tax basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury Regulations relating to the availability and calculation of depletion deductions by the unitholders. Further, because depletion is required to be computed separately by each unitholder and not by our partnership, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the unitholders for any taxable year. Moreover, the availability of percentage depletion may be reduced or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read Recent Legislative Developments. We encourage each prospective unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Deductions for Intangible Drilling and Development Costs

We elect to currently deduct intangible drilling and development costs, which we refer to as IDCs. IDCs generally include our expenses for wages, fuel, repairs, hauling, supplies and other items that are incidental to, and necessary for, the drilling and preparation of wells for the production of oil, natural gas, or geothermal energy. The option to currently deduct IDCs applies only to those items that do not have a salvage value.

Although we will elect to currently deduct IDCs, each unitholder will have the option of either currently deducting IDCs or capitalizing all or part of the IDCs and amortizing them on a straight-line basis over a 60-month period, beginning with the taxable month in which the expenditure is made. If a unitholder makes the election to amortize the IDCs over a 60-month period, no IDC preference amount in respect of those IDCs will result for alternative minimum tax purposes.

Integrated oil companies must capitalize 30% of all their IDCs (other than IDCs paid or incurred with respect to oil and natural gas wells located outside of the United States) and amortize these IDCs over 60

Table of Contents

months beginning in the month in which those costs are paid or incurred. If the taxpayer ceases to be an integrated oil company, it must continue to amortize those costs as long as it continues to own the property to which the IDCs relate. An integrated oil company is a taxpayer that has economic interests in oil or natural gas properties and also carries on substantial retailing or refining operations. An oil or natural gas producer is deemed to be a substantial retailer or refiner if it is subject to the rules disqualifying retailers and refiners from taking percentage depletion. To qualify as an independent producer that is not subject to these IDC deduction limits, a unitholder, either directly or indirectly through certain related parties, may not be involved in the refining of more than 75,000 barrels of oil (or the equivalent amount of natural gas) on average for any day during the taxable year or in the retail marketing of oil and natural gas products exceeding $5 million per year in the aggregate.

IDCs previously deducted that are allocable to property (directly or through ownership of an interest in a partnership) and that would have been included in the adjusted tax basis of the property had the IDC deduction not been taken are recaptured to the extent of any gain realized upon the disposition of the property or upon the disposition by a unitholder of interests in us. Recapture is generally determined at the unitholder level. Where only a portion of the recapture property is sold, any IDCs related to the entire property are recaptured to the extent of the gain realized on the portion of the property sold. In the case of a disposition of an undivided interest in a property, a proportionate amount of the IDCs with respect to the property is treated as allocable to the transferred undivided interest to the extent of any gain recognized. Please read Tax Considerations Disposition of Common Units Recognition of Gain or Loss in the accompanying prospectus.

The election to currently deduct IDCs may be restricted or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read Recent Legislative Developments.

Note that this discussion of IDCs relates to our direct drilling operations. IDCs incurred with respect to our investment partnerships are allocated to the investor limited partners and thus are not available to our unitholders.

Deduction for U.S. Production Activities

Subject to the limitations on the deductibility of losses discussed in the accompanying prospectus and the limitations discussed below, unitholders will be entitled to a deduction, herein referred to as the Section 199 deduction, equal to 9% of the lesser of (i) our qualified production activities income that is allocated to such unitholder or (ii) the unitholder s taxable income, but not to exceed 50% of such unitholder s IRS Form W-2 wages for the taxable year allocable to domestic production gross receipts.

Qualified production activities income is generally equal to gross receipts from domestic production activities reduced by cost of goods sold allocable to those receipts, other expenses directly associated with those receipts, and a share of other deductions, expenses and losses that are not directly allocable to those receipts or another class of income. The products produced must be manuf