Atlas Resource Partners, L.P.
Form 424B5
May 10, 2013
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Registration No. 333-180477

PROSPECTUS SUPPLEMENT

(To Prospectus dated April 13, 2012)

ATLAS RESOURCE PARTNERS, L.P.

COMMON UNITS REPRESENTING LIMITED PARTNER INTERESTS

Having an Aggregate Offering Price of Up to $25,000,000

This prospectus supplement and the accompanying prospectus relate to the offer and sale from time to time of common units representing limited partner interests of Atlas Resource Partners, L.P. having an aggregate offering price of up to $25,000,000. The common units to which this prospectus supplement and the accompanying prospectus relate will be offered over a period of time and from time to time through Deutsche Bank Securities Inc., Robert W. Baird & Co. Incorporated, MLV & Co. LLC, C&Co/PrinceRidge LLC, RBC Capital Markets, LLC, Stephens Inc., Stifel, Nicolaus & Company, Incorporated, Tuohy Brothers Investment Research, Inc. and Wells Fargo Securities, LLC, as our sales agents, or, collectively, the Sales Agents, in accordance with the terms of a distribution agreement we have entered into with them and that we have filed with the Securities and Exchange Commission, or SEC, on a current report on Form 8-K. Sales of our common units, if any, may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined in Rule 415 under the Securities Act of 1933, as amended, or the Securities Act, including sales made directly on the New York Stock Exchange, or the NYSE, or sales made to or through a market maker other than on an exchange or through an electronic communications network.

Our common units trade on the NYSE under the symbol ARP. On May 9, 2013, the last reported sale price of our common units on the NYSE was $23.72 per common unit.

The common units will be offered at negotiated prices or prevailing market prices at the time of sale. We will pay each of the Sales Agents a commission which in each case shall not be more than 2.0% of the gross sales price of all common units sold through it as our agent under the distribution agreement. The remaining sales proceeds, after deducting any expenses payable by us and any transaction fees imposed by any governmental or self-regulatory organization in connection with the sales, will equal our net proceeds for the sale of our common units and will be used as described under Use of Proceeds in this prospectus supplement. There is no arrangement for funds to be received in any escrow, trust or similar arrangement.

Under the distribution agreement, we may also sell our common units to the Sales Agents as principals for their own accounts at prices agreed upon at the time of sale. If we sell our common units to any of the Sales Agents as principals, we will enter into a separate terms agreement with such Sales Agent and we will describe that agreement in a separate prospectus supplement or pricing supplement.

Limited partnerships are inherently different from corporations. You should carefully consider the risks relating to investing in our common units and each of the risk factors described under Risk Factors on page S-8 of this prospectus supplement and on page 2 of the accompanying prospectus.

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

Deutsche Bank Securities **RBC Capital Markets** **Wells Fargo Securities**

Baird

C&Co/PrinceRidge

MLV & Co.

Stephens Inc.

Stifel

Tuohy Brothers

The date of this prospectus supplement is May 10, 2013

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PROSPECTUS SUPPLEMENT

PROSPECTUS

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 in our affairs in an amendment to this prospectus, a prospectus supplement or a future filing with the SEC incorporated by reference in this prospectus.

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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, 2012 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 March 31, 2013, 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, except as required by law.

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SUMMARY

This summary highlights information included or incorporated by reference in this prospectus supplement. It does not contain all of the information that you should consider before investing in our common units. You should read carefully the entire prospectus supplement, the accompanying prospectus, the documents incorporated by reference herein and therein and the other documents to which we refer herein and therein for a more complete understanding of this offering.

Please read Risk Factors on page S-8 of this prospectus supplement and in our Annual Report on Form 10-K for the year ended December 31, 2012, and in our subsequent filings with the SEC, each of which is incorporated by reference herein, for information regarding risks you should consider before investing in our common units.

For purposes of this prospectus supplement, unless the context clearly indicates otherwise, references to the Partnership, we, us, our and similar terms refer to Atlas Resource Partners, L.P. and its subsidiaries. References to our general partner means Atlas Resource Partners GP, LLC.

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 March 31, 2013, we own production positions in the following areas:

- the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas, a hydrocarbon producing shale in which we established a position following our acquisitions of assets from Carrizo Oil & Gas, Inc., which we refer to as Carrizo, Titan Operating, LLC, which we refer to as Titan, and DTE Energy Company, which we refer to as DTE, during 2012;

- the Appalachia basin, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region;

- the Mississippi Lime and Hunton plays in northwestern Oklahoma, an area rich in oil and natural gas liquids, or NGLs; and

- other operating areas, including the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; the Antrim Shale in Michigan, where we produce out of the biogenic region of the shale similar to the New Albany Shale; and the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry natural gas.

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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 production through the following recent transactions:

Carrizo Barnett Shale Assets On April 30, 2012, we acquired assets in the core of the Barnett Shale from Carrizo for approximately $190 million, which was funded through the private placement of $120 million of common units 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, thereby mitigating our commodity price exposure and enhancing acquisition economics.

Titan Barnett Shale Assets On July 26, 2012, we acquired Titan, which owned assets in the Barnett Shale on approximately 16,000 net acres, 90% of which are 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., 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.

DTE Fort Worth Basin Assets On December 20, 2012, we acquired 210 Bcfe of proved reserves in the Fort Worth basin from DTE for $257.4 million. The assets include 261 gross producing wells generating approximately 23 MMcfed of production at the date of acquisition on over 88,000 net acres, approximately 40% of which are held by production and approximately 33% are in continuous development. 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 it expects to commence drilling operations by early 2013. The assets acquired from DTE are in close proximity to our other assets in the Barnett Shale.

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 eight wells have been drilled and completed as of March 31,

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2013. 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 drilled five horizontal wells in Harrison County as of March 31, 2013. 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 operations of the subsidiaries of Atlas Energy (NYSE: ATLS) that held Atlas Energy s natural gas and oil development and production operations and its partnership management business, substantially all of which Atlas Energy transferred to us on March 5, 2012. Atlas Energy is a publicly-traded master limited partnership that owns 100% of our general partner Class A units and incentive distribution rights and an approximate 43.0% limited partnership interest (20,962,485 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, 2012, we raised over $1.2 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 March 31, 2013.

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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 37% of our segment margin for the year ended December 31, 2012. 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.

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 January 23, 2013, we issued $275.0 million of 7.75% senior unsecured notes due January 15, 2021, which we refer to as our 7.75% Senior Notes, in a private placement transaction at par. We used the net proceeds of such offering of approximately $267.9 million, net of placement discount and other offering-related costs of $7.1 million, to repay all of the indebtedness and accrued interest outstanding under our term loan facility and a portion of the amount outstanding under our revolving credit facility. Under the terms of our revolving credit facility, the borrowing base was reduced by 15% of the face value of our 7.75% Senior Notes to $368.8 million.

In connection with the issuance of our 7.75% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by January 23, 2014. If we do not meet the aforementioned deadline, our 7.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that we cause the exchange offer to be consummated.

Partnership Information

Atlas Resource Partners, L.P. is a Delaware limited partnership formed in October 2011. Our principal executive offices are located at Park Place Corporate Center One, 1000 Commerce Drive, Suite 400, Pittsburgh, PA 15275, and our telephone number is (877) 280-2857. Our website is *www.atlasresourcepartners.com*. Information on our website or any other website is not incorporated by reference herein and does not consitute a part of this prospectus supplement.

Additional Information

For additional information, please see Where You Can Find More Information in this prospectus supplement.

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THE OFFERING

Issuer	Atlas Resource Partners, L.P.
Common units offered	Common units with an aggregate offering price of up to $25,000,000. For a description of our common units, please read Our Partnership Agreement in the accompanying prospectus.
Manner of offering	At-the-market offering that may be made from time to time through one of our agents. See Plan of Distribution on page S-14.
NYSE Symbol	ARP
Use of proceeds	We intend to use the net proceeds from this offering, after deducting the Sales Agents commission and our offering expenses, for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. Amounts repaid under our revolving credit facility may be reborrowed to fund our ongoing capital program, potential future acquisitions or for general partnership purposes. Please read 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.
Risk factors	You should read Risk Factors on page S-8 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, Deutsche Bank Securities Inc. and RBC Capital Markets, LLC are lenders under our revolving credit facility. To the extent we use proceeds from this offering to repay indebtedness under our revolving credit facility, such

affiliates

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	may receive proceeds from this offering. Please read Plan of Distribution in this prospectus for further information.
	Daniel G. Cohen, the chairman and chief executive officer of C&Co/PrinceRidge LLC, is the son of Edward E. Cohen, the chairman of the board of directors and chief executive officer of our general partner, and the brother of Jonathan Z. Cohen, the vice chairman of the board of directors of our general partner.
Tax considerations	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 Considerations in this prospectus supplement and under the heading Tax Considerations in the accompanying prospectus.

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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.

USE OF PROCEEDS

We intend to use the net proceeds of this offering, after deducting the Sales Agents commission and our offering expenses, for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. Amounts repaid under our revolving credit facility may be reborrowed to fund our ongoing capital program, potential future acquisitions or for general partnership purposes.

Affiliates of Wells Fargo Securities, LLC, Deutsche Bank Securities Inc. and RBC Capital Markets, LLC are lenders under our revolving credit facility. To the extent we use proceeds from this offering to repay indebtedness under our revolving credit facility, such affiliates may receive proceeds from this offering. Please read Plan of Distribution in this prospectus supplement for further information.

At March 31, 2013 we had approximately $145.0 million of borrowings outstanding under our revolving credit facility with a weighted average interest rate of approximately 2.5%. The revolving credit facility matures in March 2016.

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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.

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 39.6% 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) and qualified dividend income of individuals is 20%. These rates are subject to change by new legislation at any time.

In addition, a 3.8% Medicare tax on net investment income earned by certain individuals, estates and trusts applies for taxable years beginning after December 31, 2012. For these purposes, net investment income generally includes a unitholder s allocable share of our income and gain realized by a unitholder from a sale of common units. In the case of an individual, the tax will be imposed on the lesser of (1) the unitholder s net investment income or (2) the amount by which the unitholder s modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if the unitholder is married and filing separately) or $200,000 (in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (1) undistributed net investment income, or (2) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

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

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$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.

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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 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.

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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 manufactured, produced, grown or extracted in whole or in significant part by the taxpayer in the United States.

For a partnership, the Section 199 deduction is determined at the partner level. To determine his Section 199 deduction, each unitholder will aggregate his share of the qualified production activities income allocated to him from us with the unitholder s qualified production activities income from other sources. Each unitholder must take into account his distributive share of the expenses allocated to him from our qualified production activities regardless of whether we otherwise have taxable income. However, our expenses that otherwise would be taken into account for purposes of computing the Section 199 deduction are taken into account only if and to the extent the unitholder s share of losses and deductions from all of our activities is not disallowed by the tax basis rules, the at-risk rules or the passive activity loss rules. Please read Tax Considerations Tax Consequences of Unit Ownership Limitations on Deductibility of Our Losses in the accompanying prospectus.

The amount of a unitholder s Section 199 deduction for each year is limited to 50% of the IRS Form W-2 wages actually or deemed paid by the unitholder during the calendar year that are deducted in arriving at qualified production activities income. Each unitholder is treated as having been allocated IRS Form W-2 wages from us equal to the unitholder s allocable share of our wages that are deducted in arriving at qualified production activities income for that taxable year. It is not anticipated that we or our subsidiaries will pay material wages that will be allocated to our unitholders, and thus a unitholder s ability to claim the Section 199 deduction may be limited.

A unitholder s otherwise allowable Section 199 deduction for each taxable year is reduced by 3% of the least of (i) the oil related qualified production activities income of the taxpayer for the taxable year, (ii) the qualified production activities income of the taxpayer for the taxable year, or (iii) the taxpayer s taxable income for the taxable year (determined without regard to any Section 199 deduction). For this purpose, the term oil related qualified production activities income means the qualified production activities income attributable to the production, refining, processing, transportation, or distribution of oil, gas, or any primary production thereof. We expect that most or all of our qualified production activities income will consist of oil related qualified production activities income

This discussion of the Section 199 deduction does not purport to be a complete analysis of the complex legislation and Treasury authority relating to the calculation of domestic production gross receipts, qualified production activities income, or IRS Form W-2 wages, or how such items are allocated by us to unitholders. Further, because the Section 199 deduction is required to be computed separately by each unitholder, no assurance can be given, and counsel is unable to express any opinion, as to the availability or extent of the Section 199 deduction to the unitholders. Moreover, the availability of Section 199 deductions 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. Each prospective unitholder is encouraged to consult his tax advisor to determine whether the Section 199 deduction would be available to him.

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Lease Acquisition Costs

The cost of acquiring oil and natural gas lease or similar property interests is a capital expenditure that must be recovered through depletion deductions if the lease is productive. If a lease is proved worthless and abandoned, the cost of acquisition less any depletion claimed may be deducted as an ordinary loss in the year the lease becomes worthless. Please read Depletion Deductions.

Geophysical Costs

The cost of geophysical exploration incurred in connection with the exploration and development of oil and natural gas properties in the United States are deducted ratably over a 24-month period beginning on the date that such expense is paid or incurred. This 24-month period is extended to 7 years in the case of major integrated oil companies.

Operating and Administrative Costs

Amounts paid for operating a producing well are deductible as ordinary business expenses, as are administrative costs to the extent they constitute ordinary and necessary business expenses that are reasonable in amount.

Recent Legislative Developments

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, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Please read Tax Considerations Partnership Status in the accompanying prospectus. 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.

The Obama Administration s budget proposal for fiscal year 2014 includes proposals that would, among other things, eliminate or reduce 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 and certain environmental clean-up 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.

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PLAN OF DISTRIBUTION

We have entered into a distribution agreement, dated as of May 10, 2013, with Deutsche Bank Securities Inc., as representative of the several Sales Agents thereunder from time to time, under which we may issue and sell our common units having an aggregate offering price of up to $25,000,000 from time to time through the Sales Agents, as our agents for the offer and sale of the common units, or to them for resale. Sales of our common units, if any, may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined in Rule 415 of the Securities Act, including sales made directly on the NYSE, the existing trading market for our common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network.

From time to time during the term of the distribution agreement, we and one of the Sales Agents may agree upon the terms of an agency transaction pursuant to which our common units may be sold through such Sales Agent as our agent for the offer and sale of the common units, or to them for resale. Upon reaching such agreement, such Sales Agent will deliver to us, and we will promptly indicate our acceptance of, a transaction notice specifying the length of the selling period, the amount of common units to be sold, the commission to be paid by us to such Sales Agent and the minimum price below which sales may not be made. We will submit a notice to only one Sales Agent relating to the sale of our common units on any given day. Upon receipt of our acceptance of a transaction notice, and subject to the terms and conditions of the respective distribution agreement, if acting as agent, each Sales Agent agrees to use its commercially reasonable efforts consistent with its normal trading and sales practices to sell such common units on such terms. We or any of the Sales Agents may suspend the offering of our common units at any time upon proper notice to the other, upon which the selling period will immediately terminate.

Our Sales Agents, in their capacity as agents, will not engage in any transactions that stabilize our common units.

We will pay each of the Sales Agents a commission which in each case shall not be more than 2.0% of the gross sales price of all common units sold through it as our agent under the distribution agreement. The remaining sales proceeds, after deducting any expenses payable by us and any transaction fees imposed by any governmental or self-regulatory organization in connection with the sales, will equal our net proceeds for the sale of our common units.

Under the distribution agreement, we may also sell our common units to each of our Sales Agents as principals for their own accounts at prices agreed upon at the time of sale.

Settlement for sales of our common units are generally anticipated to occur on the third trading day following the date on which any sales were made in return for payment of the net proceeds to us, unless we agree otherwise with the relevant Sales Agent. There is no arrangement for funds to be received in an escrow, trust or similar arrangement.

Sales of our common units as contemplated by this prospectus supplement will be settled through the facilities of The Depository Trust Company or by such other means as we and the Sales Agents may agree upon.

Each Sales Agent will provide written confirmation to us following the close of trading on the NYSE each day in which our common units are sold by it as agent for us under the relevant distribution agreement. Each confirmation will include the number of common units sold on that day, the gross sales price per share, the net proceeds to us and the commission payable to the Sales Agent under the distribution agreement in connection with such sales.

In connection with the sale of our common units hereunder, each of the Sales Agents may be deemed to be an underwriter within the meaning of the Securities Act, and the compensation paid to each of them may be deemed to be underwriting commissions or discounts. We have agreed to provide indemnification and contribution to each of the Sales Agents against certain civil liabilities, including liabilities under the Securities Act.

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Conflicts of Interest

Certain of the Sales Agents and their affiliates have, from time to time, performed, and may in the future perform, various financial advisory and investment banking services for us, for which they received or will receive customary fees and expenses. In the ordinary course of business the Sales Agents and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of our company. The Sales Agents and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Affiliates of Wells Fargo Securities, LLC, Deutsche Bank Securities Inc. and RBC Capital Markets, LLC are lenders under our revolving credit facility. As described under Use of Proceeds in this prospectus supplement, we may use a portion of the net proceeds from this offering to repay borrowings under our revolving credit facility.

In compliance with the guidelines of the Financial Industry Regulatory Authority, Inc., or FINRA, the maximum discount or commission to be received by any FINRA member or independent broker-dealer may not exceed 8% of the aggregate offering price of the common units offered pursuant to this prospectus. Because FINRA views the common units offered hereby as interests in a direct participation program, this offering is being made in compliance with Rule 2310 of the FINRA Rules.

Daniel G. Cohen, the chairman and chief executive officer of C&Co/PrinceRidge LLC, is the son of Edward E. Cohen, the chairman of the board of directors and chief executive officer of our general partner, and the brother of Jonathan Z. Cohen, the vice chairman of the board of directors of our general partner.

If the Sales Agents or we have reason to believe that the exemptive provisions set forth in Rule 101(c)(1) of Regulation M under the Exchange Act are not satisfied, that party will promptly notify the other and sales of the our common units under the distribution agreement will be suspended until that or other exemptive provisions have been satisfied in the judgment of the Sales Agents and us.

We estimate that the total expenses of the offering payable by us, excluding commissions or discounts payable or provided to the Sales Agents under the distribution agreement, will be approximately $0.3 million.

The offering of our common units pursuant to the distribution agreement will terminate upon the earlier of (1) the sale of all of our common units subject to the distribution agreement, (2) the termination of such distribution agreement by either us or Deutsche Bank Securities Inc. at any time in the respective party s sole discretion and (3) the date on which our shelf registration statement on Form S-3 (File No. 333-180477), filed on March 30, 2012, ceases to be effective.

Selling Restrictions

Notice to Prospective Investors in the EEA

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), other than Germany, with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of securities described in this prospectus may not be made to the public in that relevant member state other than:

- to any legal entity which is a qualified investor as defined in the Prospectus Directive;

- to fewer than 100 or, if the relevant member state has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the

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Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by the Issuer for any such offer; or

in any other circumstances falling within Article 3(2) of the Prospectus Directive;

provided that no such offer of securities shall require us or any Sales Agent to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an offer of securities to the public in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase or subscribe for the securities, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression Prospectus Directive means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the relevant member state), and includes any relevant implementing measure in each relevant member state. The expression 2010 PD Amending Directive means Directive 2010/73/EU.

We have not authorized and do not authorize the making of any offer of securities through any financial intermediary on their behalf, other than offers made by the Sales Agents with a view to the final placement of the securities as contemplated in this prospectus. Accordingly, no purchaser of the securities, other than the Sales Agents, is authorized to make any further offer of the securities on behalf of us or the Sales Agents.

Notice to Prospective Investors in the United Kingdom

The Partnership may constitute a collective investment scheme as defined by section 235 of the Financial Services and Markets Act 2000 (FSMA) that is not a recognised collective investment scheme for the purposes of FSMA (CIS) and that has not been authorised or otherwise approved. As an unregulated scheme, it cannot be marketed in the United Kingdom to the general public, except in accordance with FSMA. This prospectus is only being distributed in the United Kingdom to, and is only directed at:

(1) if the Partnership is a CIS and is marketed by a person who is an authorised person under FSMA, (a) investment professionals falling within Article 14(5) of the Financial Services and Markets Act 2000 (Promotion of Collective Investment Schemes) (Exemptions) Order 2001, as amended (the CIS Promotion Order) or (b) high net worth companies and other persons falling within Article 22(2)(a) to (d) of the CIS Promotion Order; or

(2) otherwise, if marketed by a person who is not an authorised person under FSMA, (a) persons who fall within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the Financial Promotion Order) or (b) Article 49(2)(a) to (d) of the Financial Promotion Order; and

(3) in both cases (1) and (2) to any other person to whom it may otherwise lawfully be made (all such persons together being referred to as relevant persons).

Our common units are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such common units will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

An invitation or inducement to engage in investment activity (within the meaning of Section 21 of FSMA) in connection with the issue or sale of any common units which are the subject of the offering contemplated by this prospectus will only be communicated or caused to be communicated in circumstances in which Section 21(1) of FSMA does not apply to us.

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Notice to Prospective Investors in Switzerland

This prospectus is being communicated in Switzerland to a small number of selected investors only