UNITED STATES SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549  
FORM 10-K  

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934  
For the fiscal year ended December 31, 2013  

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934  
For the transition period from ___ to ___  

Commission file number 001-33055  

BreitBurn Energy Partners L.P.  
(Exact Name of Registrant as Specified in Its Charter)  

Delaware  
(State or Other Jurisdiction of Incorporation or Organization)  

74-3169953  
(I.R.S. Employer Identification No.)  

515 South Flower Street, Suite 4800  
Los Angeles, California  
(Address of Principal Executive Offices)  

90071  
(Zip Code)  

Registrant’s telephone number, including area code: (213) 225-5900  

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

<table>
<thead>
<tr>
<th>Title of each class</th>
<th>Name of each exchange on which registered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Units Representing Limited Partner Interests</td>
<td>The NASDAQ Stock Market LLC</td>
</tr>
</tbody>
</table>

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐  

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

Accelerated filer ☒  
Non-accelerated filer ☐  
(Do not check if a smaller reporting company) Smaller reporting company ☐  

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

The aggregate market value of the Common Units held by non-affiliates was approximately $1.8 billion on June 28, 2013, the last business day of the registrant’s most recently completed second fiscal quarter, based on $18.25 per unit, the last reported sales price on The NASDAQ Global Select Market on such date.  

As of February 27, 2014, there were 119,201,681 Common Units outstanding.  

Documents Incorporated By Reference: Certain information called for in Items 10, 11, 12, 13 and 14 of Part III are incorporated by reference from the registrant’s definitive proxy statement for the 2014 annual meeting of unitholders to be held on June 19, 2014.
### Glossary of Oil and Gas Terms, Description of References

**PART I**

<table>
<thead>
<tr>
<th>Item 1</th>
<th>Business</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Item 1A</td>
<td>Risk Factors</td>
<td>26</td>
</tr>
<tr>
<td>Item 1B</td>
<td>Unresolved Staff Comments</td>
<td>48</td>
</tr>
<tr>
<td>Item 2</td>
<td>Properties</td>
<td>48</td>
</tr>
<tr>
<td>Item 3</td>
<td>Legal Proceedings</td>
<td>48</td>
</tr>
<tr>
<td>Item 4</td>
<td>Mine Safety Disclosures</td>
<td>48</td>
</tr>
</tbody>
</table>

**PART II**

<table>
<thead>
<tr>
<th>Item 5</th>
<th>Market For Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities</th>
<th>49</th>
</tr>
</thead>
<tbody>
<tr>
<td>Item 6</td>
<td>Selected Financial Data</td>
<td>52</td>
</tr>
<tr>
<td>Item 7</td>
<td>Management’s Discussion and Analysis of Financial Condition and Results of Operations</td>
<td>57</td>
</tr>
<tr>
<td>Item 7A</td>
<td>Quantitative and Qualitative Disclosures About Market Risk</td>
<td>74</td>
</tr>
<tr>
<td>Item 8</td>
<td>Financial Statements and Supplementary Data</td>
<td>76</td>
</tr>
<tr>
<td>Item 9</td>
<td>Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</td>
<td>76</td>
</tr>
<tr>
<td>Item 9A</td>
<td>Controls and Procedures</td>
<td>76</td>
</tr>
<tr>
<td>Item 9B</td>
<td>Other Information</td>
<td>76</td>
</tr>
</tbody>
</table>

**PART III**

<table>
<thead>
<tr>
<th>Item 10</th>
<th>Directors, Executive Officers and Corporate Governance</th>
<th>78</th>
</tr>
</thead>
<tbody>
<tr>
<td>Item 11</td>
<td>Executive Compensation</td>
<td>79</td>
</tr>
<tr>
<td>Item 12</td>
<td>Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters</td>
<td>79</td>
</tr>
<tr>
<td>Item 13</td>
<td>Certain Relationships and Related Transactions, and Director Independence</td>
<td>79</td>
</tr>
<tr>
<td>Item 14</td>
<td>Principal Accounting Fees and Services</td>
<td>79</td>
</tr>
</tbody>
</table>

**PART IV**

| Item 15 | Exhibits and Financial Statement Schedules | 80 |

**Signatures**


The following is a description of the meanings of some of the oil and gas industry terms that may be used in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(6), (22) and (31) of Regulation S-X.

**API:** The specific gravity or density of oil expressed in terms of a scale devised by the American Petroleum Institute.

**ASC:** Accounting Standards Codification.

**Bbl:** One stock tank barrel, or 42 U.S. gallons of liquid volume, of oil or other liquid hydrocarbons.

**Bbl/d:** Bbl per day.

**Bcf:** One billion cubic feet of natural gas.

**Bcfe:** One billion cubic feet equivalent, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

**Boe:** One barrel of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

**Boe/d:** Boe per day.

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

**CO₂:** Carbon dioxide.

**CO₂ Flooding:** A tertiary recovery method whereby carbon dioxide is injected into a reservoir to enhance hydrocarbon recovery.

**completion:** The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

**deterministic method:** The method of estimating revenues using a single value for each parameter (from the geoscience engineering economic data) in reserves calculations.

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

**differential:** The difference between a benchmark price of oil and natural gas, such as the WTI spot oil price, and the wellhead price received.

**dry hole or well:** A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

**economically producible:** A resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

**exploitation:** A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

**exploratory well:** A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is not a development well.
**FASB:** Financial Accounting Standards Board.

**field:** An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

**gross acres or gross wells:** The total acres or wells, as the case may be, in which a working interest is owned.

**ICE:** Intercontinental Exchange.

**LIBOR:** London Interbank Offered Rate.

**MBbls:** One thousand barrels of oil or other liquid hydrocarbons.

**MBoe:** One thousand barrels of oil equivalent.

**MBoeld:** One thousand barrels of oil equivalent per day.

**Mcf:** One thousand cubic feet of natural gas.

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

**Mcf/e:** One thousand cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

**MichCon:** Michigan Consolidated Gas Company.

**MMBbls:** One million barrels of oil or other liquid hydrocarbons.

**MMBoe:** One million barrels of oil equivalent.

**MMBtu:** One million British thermal units.

**MMBtu/d:** One million British thermal units per day.

**MMcf:** One million cubic feet of natural gas.

**MMcf/e:** One million cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

**MMcfeld:** One million cubic feet of natural gas equivalent per day, determined using the ratio of one Bbl of oil to six Mcf of natural gas.

**net acres or net wells:** The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

**NGLs:** The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

**NYMEX:** New York Mercantile Exchange.

**oil:** Crude oil and condensate.

**productive well:** A well that is producing or that is mechanically capable of production.

**proved developed reserves:** Proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to
the cost of a new well, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. This definition of proved developed reserves has been abbreviated from the applicable definition contained in Rule 4-10(a)(6) of Regulation S-X.

**proved reserves**: The estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic and operating conditions and government regulations. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. This definition of proved reserves has been abbreviated from the applicable definition contained in Rule 4-10(a)(22) of Regulation S-X.

**proved undeveloped reserves** or **PUDs**: Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. This definition of proved undeveloped reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(31) of Regulation S-X.

**recompletion**: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

**reserve**: Estimated remaining quantities of mineral deposits anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

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

**standardized measure**: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

**undeveloped acreage**: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

**US GAAP**: Generally accepted accounting principles in the United States.

**West Texas Intermediate ("WTI")**: Light, sweet oil with high API gravity and low sulfur content used as the benchmark for U.S. crude oil refining and trading. WTI is deliverable at Cushing, Oklahoma to fill NYMEX futures contracts for light, sweet crude oil.

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

**workover**: Operations on a producing well to restore or increase production.
References in this report to “the Partnership,” “we,” “our,” “us” or like terms refer to BreitBurn Energy Partners L.P. and its subsidiaries. References in this filing to “PCEC” or the “Predecessor” refer to Pacific Coast Energy Company LP, formerly named BreitBurn Energy Company L.P., our predecessor, and its predecessors and subsidiaries. References in this filing to “BreitBurn GP” or the “General Partner” refer to BreitBurn GP, LLC, our general partner and our wholly-owned subsidiary. References in this filing to “BreitBurn Corporation” refer to Strand Energy Company, a corporation owned by Randall Breitenbach, a member of the Board of Directors of our General Partner, and Halbert Washburn, the Chief Executive Officer and a member of the Board of Directors of our General Partner. References in this filing to “BreitBurn Management” refer to BreitBurn Management Company, LLC, our administrative manager and wholly-owned subsidiary. References in this filing to “BOLP” or “BreitBurn Operating” refer to BreitBurn Operating L.P., our wholly-owned operating subsidiary. References in this filing to “BOGP” refer to BreitBurn Operating GP, LLC, the general partner of BOLP. References in this filing to “BEPI” refer to BreitBurn Energy Partners I, L.P. References in this filing to “Utica” refer to BreitBurn Collingwood Utica LLC, our wholly-owned subsidiary formed September 17, 2010. References in this filing to “Quicksilver” refer to Quicksilver Resources Inc., from whom we acquired oil and gas properties and facilities in Michigan, Indiana and Kentucky on November 1, 2007.
PART I

Item 1. Business.

Cautionary Statement Regarding Forward-Looking Information

Certain statements and information in this Annual Report on Form 10-K ("this report") may constitute "forward-looking statements." The words "believe," "expect," "anticipate," "plan," "intend," "future," "projected," "goal," "should," "could," "would" or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future developments and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those described in (1) Part I—Item 1A "—Risk Factors" and elsewhere in this report, and (2) our Quarterly Reports on Form 10-Q and Current Reports on Form 8-K filed with the Securities and Exchange Commission (the "SEC").

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

Overview

We are an independent oil and gas partnership focused on the acquisition, exploitation and development of oil, NGL and gas properties in the United States. Our objective is to manage our oil, NGL and gas producing properties for the purpose of generating cash flow and making distributions to our unitholders. Our assets consist primarily of producing and non-producing oil, NGL and natural gas reserves located primarily in:

- the Antrim Shale and several non-Antrim formations in Michigan;
- the Oklahoma Panhandle;
- the Permian Basin in Texas;
- the Evanston, Green River, Wind River, Big Horn and Powder River Basins in Wyoming;
- the Los Angeles and San Joaquin Basins in California;
- the Sunniland Trend in Florida; and
- the New Albany Shale in Indiana and Kentucky.

Our assets are characterized by stable, long-lived production and proved reserve life indexes averaging greater than 15 years. We have high net revenue interests in our properties. As of December 31, 2013, our total estimated proved reserves were 214.3 MMBoe, of which approximately 53% was oil, 7% was NGLs and 40% was natural gas. Our production in 2013 was 11.0 MMBoe, of which approximately 51% was oil, 6% was NGLs and 43% was natural gas.

We are a Delaware limited partnership formed in 2006 and have been publicly traded since October 2006. Our general partner is BreitBurn GP, a Delaware limited liability company, also formed in 2006, and has been our wholly-owned subsidiary since June 2008. The board of directors of our General Partner (the "Board") has sole responsibility for conducting our business and managing our operations. We conduct our operations through a wholly-owned subsidiary, BOLP, and BOLP’s general partner, BOGP. We own all of the ownership interests in BOLP and BOGP.

In 2008, we acquired BreitBurn Management and its interest in the General Partner, resulting in BreitBurn Management and the General Partner becoming our wholly-owned subsidiaries. BreitBurn Management manages our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. See Note 5 to the consolidated financial statements in this report for more information regarding our relationship with BreitBurn Management.
Available Information

Our internet website address is www.breitburn.com. We make available, free of charge at the “Investor Relations” portion of our website, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such reports are electronically filed with, or furnished to, the SEC. The information contained on our website does not constitute part of this report.

The SEC maintains an internet website that contains these reports at www.sec.gov. Any materials that the Partnership files with the SEC may be read or copied at the SEC’s Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

Structure

The following diagram depicts our organizational structure as of December 31, 2013:

![Organizational Structure Diagram]

As of both December 31, 2013 and February 27, 2014, we had 119.2 million common units representing limited partner interests in us (“Common Units”) outstanding.

Long-Term Business Strategy

Our long-term goals are to manage our current and future oil, NGL and natural gas producing properties for the purpose of generating cash flow and making distributions to our unitholders. In order to meet these objectives, we plan to continue to follow our core investment strategy, which includes the following principles:

- Acquire long-lived assets with low-risk exploitation and development opportunities;
- Use our technical expertise and state-of-the-art technologies to identify and implement successful exploitation techniques to optimize reserve recovery;
- Reduce cash flow volatility through commodity price and interest rate derivatives; and
- Maximize asset value and cash flow stability through our operating and technical expertise.

Acquisitions

2013 Acquisitions

Oklahoma Panhandle Acquisitions. On July 15, 2013, we completed the acquisition of principally oil properties and midstream assets located in Oklahoma, New Mexico and Texas, certain CO₂ supply contracts, certain oil swaps and interests in certain entities from Whiting Oil and Gas Corporation (“Whiting”) for approximately $845 million in cash (the “Whiting Acquisition”), including post-closing adjustments. We also completed the acquisition of additional interests in certain of the acquired assets in the Oklahoma Panhandle from other sellers for an additional $30 million in July 2013 (together with the
Whiting Acquisition, the “Oklahoma Panhandle Acquisitions”). The properties acquired in Whiting Acquisitions were comprised of approximately 84% oil, 11% NGLs and 5% natural gas.

2013 Permian Basin Acquisitions. On December 30, 2013, we completed acquisitions of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P. for approximately $282 million in cash (the “CrownRock III Acquisition”). The assets acquired in the CrownRock III Acquisition and additional interests in certain of the acquired assets in the Permian Basin from other sellers for an additional $20 million in December 2013 (together with the CrownRock III Acquisition, the “2013 Permian Basin Acquisitions”). The properties acquired in the 2013 Permian Basin Acquisitions were comprised of approximately 63% oil, 20% NGLs and 17% natural gas.

2012 Acquisitions

NiMin Acquisition. In June 2012, we completed the acquisition of oil properties located in Park County in the Big Horn Basin of Wyoming from Legacy Energy, Inc., a wholly-owned subsidiary of NiMin Energy Corp. (the “NiMin Acquisition”), for approximately $95 million in cash.


AEO Acquisition. In November 2012, we completed the acquisition of principally oil properties from American Energy Operations, Inc. (“AEO”) located in the Belridge Field in the San Joaquin Basin in Kern County, California (the “AEO Acquisition”) for approximately $38 million in cash and approximately 3.01 million of our Common Units valued at $56 million.

2011 Acquisitions

Greasewood Acquisition. In July 2011, we completed the acquisition of oil properties in the Powder River Basin in eastern Wyoming (the “Greasewood Acquisition”) for approximately $57 million in cash.

Cabot Acquisition. In October 2011, we completed the acquisition of principally natural gas properties located primarily in the Evanston and Green River Basins in southwestern Wyoming (the “Cabot Acquisition”) for approximately $281 million in cash. The properties acquired in the Cabot Acquisition were comprised of approximately 95% natural gas.

2014 Outlook

We expect our full year 2014 oil and gas capital spending program to be between $325 million and $345 million, including capitalized engineering costs and excluding potential acquisitions, compared with approximately $295 million in 2013. In 2014, we anticipate spending approximately 92% principally on oil projects in Texas, California and Oklahoma and approximately 8% principally on oil projects in Florida, Wyoming and Michigan. We anticipate 85% of our total capital spending will be focused on drilling and rate-generating projects that are designed to increase or add to production or reserves. We plan to drill 168 wells with 156 wells expected in Texas and California and 12 wells expected in Wyoming, Michigan and Florida. Without considering potential acquisitions, we expect our 2014 production to be between 13.6 MMBoe and 14.4 MMBoe.

Commodity hedging remains an important part of our strategy to reduce cash flow volatility. We use swaps, collars and options for managing risk relating to commodity prices. As of February 27, 2014, we had approximately 76% of our expected 2014 production hedged. For 2014, we have 20,114 Bbl/d of oil and 55,100 MMBtu/d of natural gas hedged at average prices of approximately $93.70 per Bbl and $4.95 per MMBtu, respectively. For 2015, we have 17,989 Bbl/d of oil and 56,700 MMBtu/d of natural gas hedged at average prices of approximately $93.54 per Bbl and $4.94 per MMBtu, respectively. For 2016, we have 15,011 Bbl/d of oil and 41,700 MMBtu/d of natural gas hedged at average prices of approximately $89.48 per Bbl and $4.32 per MMBtu, respectively. For 2017, we have 8,269 Bbl/d of oil and 18,571 MMBtu/d of natural gas hedged at average prices of approximately $84.71 per Bbl and $4.44 per MMBtu, respectively. For 2018, we have 493 Bbl/d of oil and 1,870 MMBtu/d of natural gas hedged at average prices of approximately $82.20 per Bbl and $4.15 per MMBtu, respectively.
Consistent with our long-term business strategy, we intend to continue to actively pursue oil and natural gas acquisition opportunities in 2014.

Properties

Our properties include oil, natural gas and midstream assets in Michigan, Indiana and Kentucky, including fields in the Antrim Shale in Michigan and the New Albany Shale in Indiana and Kentucky, transmission and gathering pipelines, two gas processing plants and four NGL recovery plants. Our properties also include oil and natural gas and midstream assets located in Oklahoma, New Mexico and Texas, including the Postle Field, the Northeast Hardesty Unit and the Dry Trails gas plant, all of which are located in Texas County, Oklahoma. We own a 51-mile oil pipeline in Oklahoma that connects with Texas that is a common carrier and the 120-mile Transpetco Pipeline, a CO₂ transportation pipeline delivering product from New Mexico to the Postle Field in Oklahoma. Our properties also include fields in the Permian Basin in Texas, the Evanston and Green River Basins in southwestern Wyoming, the Wind River and Big Horn Basins in central Wyoming, the Powder River Basin in eastern Wyoming, the Los Angeles Basin in California, the Belridge Field in the San Joaquin Basin in California and in Florida’s Sunniland Trend.

BreitBurn Management manages all of our properties and employs production and reservoir engineers, geologists and other specialists, as well as field personnel. On a net production basis, we operated approximately 86% of our production in 2013. As the operator, we design and manage the development of wells and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. We engage independent contractors to provide all the equipment and personnel associated with these activities.

Reserves and Production

As of December 31, 2013, our total estimated proved reserves were 214.3 MMBoe, of which approximately 53% was oil, 7% was NGLs and 40% was natural gas. As of December 31, 2012, our total estimated proved reserves were 149.4 MMBoe, of which approximately 49% was oil, 4% was NGLs, and 47% was natural gas. The net increase in our total estimated proved reserves of 64.9 MMBoe from December 31, 2012 to December 31, 2013 included additions from acquisitions in 2013 of 60.9 MMBoe, positive reserve revisions of 13.7 MMBoe and 1.3 MMBoe in extensions and discoveries offset by 11.0 MMBoe of production. The reserve revisions in 2013 were primarily the result of an 86.0 Bcf increase in natural gas reserves and 2.7 MMBoe increase in NGL reserves driven primarily by an increase in commodity prices and additional drilling, recompletions and workovers, offset by a 3.3 MMBbl decrease in oil reserves due to lower performance. The unweighted average first-day-of-the-month oil and natural gas prices used to determine our total estimated proved reserves as of December 31, 2013 were $96.94 per Bbl of oil for WTI spot price, $108.32 per Bbl of oil for ICE Brent and $3.67 per MMBtu of natural gas for Henry Hub spot price, compared to $94.71 per Bbl of oil for WTI spot price, $111.77 per Bbl of oil for ICE Brent and $2.76 per MMBtu of natural gas for Henry Hub spot price in 2012.
The following table summarizes our estimated proved reserves and production by state as of December 31, 2013:

<table>
<thead>
<tr>
<th>State</th>
<th>Total (MMBoe) (a)</th>
<th>Oil (MMBbl)</th>
<th>NGLs (MMBbl)</th>
<th>Natural Gas (Bcf)</th>
<th>% Proved Developed</th>
<th>% Total</th>
<th>Year Ended December 31, 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Michigan</td>
<td>58.2</td>
<td>3.7</td>
<td>1.0</td>
<td>320.7</td>
<td>98%</td>
<td>27%</td>
<td>3,212</td>
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<tr>
<td>Oklahoma</td>
<td>43.6</td>
<td>36.7</td>
<td>4.9</td>
<td>12.1</td>
<td>69%</td>
<td>20%</td>
<td>1,217</td>
</tr>
<tr>
<td>Texas</td>
<td>40.9</td>
<td>23.2</td>
<td>9.7</td>
<td>47.9</td>
<td>56%</td>
<td>19%</td>
<td>1,423</td>
</tr>
<tr>
<td>Wyoming</td>
<td>36.6</td>
<td>17.9</td>
<td>—</td>
<td>112.3</td>
<td>80%</td>
<td>17%</td>
<td>2,561</td>
</tr>
<tr>
<td>California</td>
<td>23.3</td>
<td>22.1</td>
<td>—</td>
<td>7.0</td>
<td>89%</td>
<td>11%</td>
<td>1,690</td>
</tr>
<tr>
<td>Florida</td>
<td>9.7</td>
<td>9.7</td>
<td>—</td>
<td>—</td>
<td>100%</td>
<td>5%</td>
<td>664</td>
</tr>
<tr>
<td>Indiana/Kentucky</td>
<td>2.0</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>100%</td>
<td>1%</td>
<td>216</td>
</tr>
<tr>
<td>Total</td>
<td>214.3</td>
<td>113.3</td>
<td>15.6</td>
<td>512.2</td>
<td>81%</td>
<td>100%</td>
<td>10,983</td>
</tr>
</tbody>
</table>

(a) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a Bbl of oil equivalent for natural gas is significantly less than the price for a Bbl of oil.

(b) For properties acquired during 2013, production and average daily production figures are based on activities from acquisition date to December 31, 2013.

The following table summarizes our estimated reserves and production by major field as of December 31, 2013:

<table>
<thead>
<tr>
<th>Field</th>
<th>As of December 31, 2013</th>
<th>Year Ended December 31, 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total (MMBoe) (a)</td>
<td>Oil (MMBbl)</td>
</tr>
<tr>
<td>Antrim Shale</td>
<td>49.6</td>
<td>—</td>
</tr>
<tr>
<td>Postle Field</td>
<td>40.3</td>
<td>33.4</td>
</tr>
<tr>
<td>Spraberry Trend</td>
<td>40.9</td>
<td>23.2</td>
</tr>
<tr>
<td>All others</td>
<td>83.5</td>
<td>56.7</td>
</tr>
<tr>
<td>Total</td>
<td>214.3</td>
<td>113.3</td>
</tr>
</tbody>
</table>

(a) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a Bbl of oil equivalent for natural gas is significantly less than the price for a Bbl of oil.

(b) For properties acquired during 2013, production and average daily production figures are based on activities from acquisition date to December 31, 2013.

As of December 31, 2013, proved undeveloped reserves were 40.9 MMBoe compared to 29.7 MMBoe as of December 31, 2012. The Oklahoma Panhandle Acquisitions and the 2013 Permian Basin Acquisitions added 13.7 MMBoe and 9.5 MMBoe, respectively, of proved undeveloped reserves. During 2013, we incurred $160.1 million in capital expenditures and drilled 122 wells related to the conversion of estimated proved undeveloped reserves to estimated proved developed reserves. During 2013, we converted 7.1 MMBbl of oil, 1.0 MMBbl of NGLs and 9.6 Bcf of natural gas from estimated proved undeveloped reserves to estimated proved developed reserves. As of December 31, 2013, we had no estimated proved undeveloped reserves that have remained undeveloped for more than five years, and we expect to develop all estimated proved undeveloped reserves within the next five years.
As of December 31, 2013, the total standardized measure of discounted future net cash flows was $3.2 billion. During 2013, we filed estimates of oil and gas reserves as of December 31, 2012 with the U.S. Department of Energy, which were consistent with the reserve data as of December 31, 2012 as reported in Note A in the supplemental information to the consolidated financial statements in this report.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development costs and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. See Part I—Item 1A “—Risk Factors” in this report for a description of some of the risks and uncertainties associated with our business and reserves.

The information in this report relating to our estimated proved oil and gas reserves is based upon reserve reports prepared as of December 31, 2013. Estimates of our proved reserves were prepared by Cawley, Gillespie & Associates, Inc. (“CGA”), Netherland, Sewell & Associates, Inc. (“NSAI”) and Schlumberger PetroTechnical Services (“SLB”), independent petroleum engineering firms. CGA prepares reserve data for our Oklahoma properties, NSAI prepares reserve data for our California, Wyoming, Texas and Florida properties, and SLB prepares reserve data for our Michigan, Indiana and Kentucky properties. The reserve estimates are reviewed and approved by members of our senior engineering staff and management. The process performed by CGA, NSAI and SLB to prepare reserve amounts included their estimation of reserve quantities, future producing rates, future net revenue and the present value of such future net revenue. CGA, NSAI and SLB also prepared estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a)(22) and subsequent SEC staff interpretations and guidance. In the conduct of their preparation of the reserve estimates, CGA, NSAI and SLB did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of their work, something came to their attention which brought into question the validity or sufficiency of any such information or data, they did not rely on such information or data until they had satisfactorily resolved their questions relating thereto.

The technical person, employed by our General Partner, primarily responsible for overseeing preparation of the reserves estimates and the third party reserve reports is Mark L. Pease, the President and Chief Operating Officer of our General Partner. Mr. Pease received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines in 1979. Prior to joining our General Partner, Mr. Pease was Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation. Mr. Pease has over 30 years of experience working in various capacities in the energy industry, including acquisition analysis, reserve estimation, reservoir engineering and operations engineering. Mr. Pease consults with CGA, NSAI and SLB during the reserve estimation process to review properties, assumptions and relevant data.

See exhibits 99.1 to this report for the estimates of proved reserves provided by NSAI, exhibit 99.2 to this report for the estimates of proved reserves provided by SLB and exhibit 99.3 to this report for the estimates of proved reserves provided by CGA. We only employ large, widely known, highly regarded and reputable engineering consulting firms. Not only the firms, but the technical persons that sign and seal the reports are licensed and certify that they meet all professional requirements. Licensing requirements formally require mandatory continuing education and professional qualifications. See Supplemental Note A to the consolidated financial statements in this report for further details about the qualifications of the technical persons at CGA, NSAI and SLB primarily responsible for preparing the reserves estimates.

**Michigan**

For the year ended December 31, 2013, our average production from our Michigan properties was approximately 8.8 MBoe/d or 52.8 MMcfe/d. As of December 31, 2013, our estimated proved reserves attributable to our Michigan properties were 58.2 MMBoe, or approximately 27% of our total estimated proved reserves. As of December 31, 2013, approximately 92% of our Michigan total estimated proved reserves were natural gas. Our integrated midstream assets enhance the value of our Michigan properties as gas is sold at MichCon City-Gate prices, and we have no significant reliance on third party transportation. We have interests in 3,396 productive wells in Michigan, and we operated approximately 56% of those wells.

In 2013, we drilled four wells, re-drilled one well and completed 15 recompletions in Michigan. Our capital spending in Michigan for the year ended December 31, 2013 was approximately $9.3 million.
The Antrim Shale underlies a large percentage of our Michigan acreage; wells tend to produce relatively predictable amounts of natural gas in this reservoir. On average, our Antrim Shale wells have a proved reserve life of greater than 21 years. Since reserve quantities and production levels over a large number of wells are fairly predictable, maximizing per well recoveries and minimizing per unit production costs through a sizable well-engineered drilling program are the keys to profitable Antrim Shale development. Growth opportunities include infill drilling and recompletions, horizontal drilling and bolt-on acquisitions.

Our non-Antrim interests are located in several reservoirs including the Prairie du Chien, Richfield, Detroit River Zone III and Niagaran pinnacle reefs.

**Oklahoma**

On July 15, 2013, we completed the Whiting Acquisition to acquire oil properties in the Oklahoma Panhandle in the western region of Oklahoma. For the year ended December 31, 2013, the properties produced approximately 7.2 MBoe/d since the acquisition. As of December 31, 2013, estimated proved reserves attributable to our Oklahoma properties were 43.6 MMBoe, or approximately 20% of our total estimated proved reserves. Approximately 84% of our Oklahoma total estimated proved reserves were oil, 11% were NGLs and 5% were natural gas. In 2013, we drilled four new productive development wells in Oklahoma. Our capital spending in Oklahoma for the year ended December 31, 2013 was approximately $43.9 million. In total, we have interests in 242 productive wells in Oklahoma, and we operated approximately 98% of those wells.

The Whiting Acquisition included the Postle Field, which currently has active CO₂ flooding projects, and the Northeast Hardesty Unit, both of which are located in Texas County, Oklahoma. We have a contracted supply of CO₂ in the Bravo Dome Field in New Mexico, with step-in rights, for 143 Bcf over the next 10 to 15 years, which when coupled with recycled CO₂, we expect will provide the volumes required to produce our estimated proved reserves. As part of the acquisition and the purchase of additional interests, we are also the sole owner of the Dry Trails gas plant located in Texas County, Oklahoma. This plant is comprised of two trains, each with a processing capacity of approximately 40 MMcf/d. One of the trains utilizes a membrane technology to extract CO₂ from the produced wellhead mixtures of hydrocarbon and CO₂ gas, so that it can be used for re-injection or sales. In addition, we own 100% in a CO₂ transportation pipeline delivering product from New Mexico to the Postle Field in Oklahoma.

**Texas**

Our Texas properties are primarily located in the Spraberry Trend located in Howard, Martin and Midland counties in Texas. For the year ended December 31, 2013, our average production from our Texas properties in the Permian Basin was approximately 3.9 MBoe/d. As of December 31, 2013, estimated proved reserves attributable to our Texas properties were 40.9 MMBoe, or approximately 19% of our total estimated proved reserves. As of December 31, 2013, approximately 57% of our Texas total estimated proved reserves were oil, 24% were NGLs and 19% were natural gas. In 2013, we drilled 53 new productive development wells in Texas. Our capital spending in Texas for the year ended December 31, 2013 was approximately $104.3 million. In total, we have interests in 230 productive wells in Texas, and we operated approximately 92% of those wells.

**Wyoming**

For the year ended December 31, 2013, our average production from our Wyoming fields was approximately 7.0 MBoe/d. As of December 31, 2013, estimated proved reserves attributable to our Wyoming properties were 36.6 MMBoe, or approximately 17% of our total estimated proved reserves. As of December 31, 2013, approximately 51% of our Wyoming total estimated proved reserves were natural gas and 49% oil. In 2013, we drilled 21 new productive development wells, 19 recompletions of existing productive wells and 2 workovers in Wyoming. Our capital spending in Wyoming for the year ended December 31, 2013 was approximately $26.4 million. In total, we have interests in 982 productive wells in Wyoming, and we operated approximately 66% of those wells.

Our Wyoming properties consist primarily of oil properties in the Powder River Basin in eastern Wyoming, principally natural gas properties in the Evanston and Green River Basins in southwestern Wyoming and principally oil fields in the Wind River and Big Horn Basins in central Wyoming, including Gebo, North Sunshine, Black Mountain, Hidden Dome, Sheldon Dome, Rolff Lake in Fremont County, West Oregon Basin and Half Moon.
**California**

For the year ended December 31, 2013, our average California production was approximately 4.6 MBoe/d. As of December 31, 2013, estimated proved reserves attributable to our California properties were 23.3 MMBoe, or approximately 11% of our total estimated proved reserves. As of December 31, 2013, approximately 95% of our California total estimated proved reserves were oil. In 2013, we drilled 34 productive wells, six recompletions and 12 workovers in California. Our capital spending in California for the year ended December 31, 2013 was approximately $81.1 million. In total, we have interests in 441 productive wells in California, and we operated 100% of those wells.

Our operations in California are concentrated in several large, complex oil fields within the Los Angeles Basin, including the Santa Fe Springs, East Coyote, Sawtelle, Rosecrans and Brea Olinda fields, the Alamitos lease of the Seal Beach Field and the Recreation Park lease of the Long Beach Field. We also operate oil properties in the Belridge Field in the San Joaquin Basin in Kern County, California.

**Florida**

For the year ended December 31, 2013, our average Florida production was approximately 1.8 MBoe/d. As of December 31, 2013, estimated proved reserves attributable to our Florida properties were 9.7 MMBbls, or approximately 5% of our total estimated proved reserves. Production is from the Cretaceous Sunniland Trend of the South Florida Basin. Each of our Florida fields is 100% oil. Production from the Raccoon Point field currently accounts for more than half of our Florida production. In 2013, we drilled three productive wells in Florida. Our capital spending in Florida for the year ended December 31, 2013 was approximately $29.5 million. In total, we have interests in 27 productive wells in Florida, and we operated 100% of those wells.

**Indiana/Kentucky**

For the year ended December 31, 2013, our average Indiana and Kentucky production was approximately 0.6 MBoe/d or 4.7 MMcf/d. As of December 31, 2013, estimated proved reserves attributable to our Indiana and Kentucky properties were 2.0 MMBoe, or 1% of our total estimated proved reserves. Our capital spending in Indiana and Kentucky for the year ended December 31, 2013 was less than $0.1 million. In total, we have interests in 241 productive wells in Indiana and Kentucky, and we operated 100% of those wells.

Our operations in the New Albany Shale of southern Indiana and northern Kentucky include 21 miles of high pressure gas pipeline that interconnects with the Texas Gas Transmission interstate pipeline. The New Albany Shale has over 100 years of production history.
### Production and Price History

The following table summarizes our production and sales prices of oil, NGLs and natural gas for the years ended December 31, 2013, 2012, and 2011.

<table>
<thead>
<tr>
<th></th>
<th>For Year Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td><strong>Net Production</strong></td>
<td></td>
</tr>
<tr>
<td>Oil (MBbl)</td>
<td>5,651</td>
</tr>
<tr>
<td>NGL (MBbl)</td>
<td>640</td>
</tr>
<tr>
<td>Natural gas (MMcf)</td>
<td>28,156</td>
</tr>
<tr>
<td>Total (MBoe)</td>
<td>10,983</td>
</tr>
<tr>
<td>Average daily production (Boe/d)</td>
<td>30,091</td>
</tr>
<tr>
<td><strong>Average Realized Sales Price (a)</strong></td>
<td></td>
</tr>
<tr>
<td>Oil price per Bbl</td>
<td>$ 93.67</td>
</tr>
<tr>
<td>NGL price per Bbl</td>
<td>$ 35.25</td>
</tr>
<tr>
<td>Natural gas price per Mcf</td>
<td>$ 3.82</td>
</tr>
<tr>
<td>Total price per Boe</td>
<td>$ 60.05</td>
</tr>
<tr>
<td><strong>Average Unit Cost per Boe</strong></td>
<td></td>
</tr>
<tr>
<td>Lease operating expense</td>
<td>$ 19.69</td>
</tr>
<tr>
<td>Production taxes</td>
<td>$ 4.21</td>
</tr>
<tr>
<td><strong>Total lease operating expense</strong></td>
<td>$ 23.90</td>
</tr>
</tbody>
</table>

(a) Excludes the effect of derivatives.
The following table summarizes our production and sales prices of oil, NGLs and natural gas for our Antrim Shale, Spraberry Trend and Postle Field, as they each represent more than 15% of our total proved reserves.

<table>
<thead>
<tr>
<th></th>
<th>Antrim Shale (a)</th>
<th>Spraberry Trend (b)</th>
<th>Postle Field (c)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Production</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil production (MBbl)</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Natural gas production (MMcf)</td>
<td>14,468</td>
<td>15,135</td>
<td>15,942</td>
</tr>
<tr>
<td>NGL production (MBbl)</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Total production (MBoe)</td>
<td>2,411</td>
<td>2,523</td>
<td>2,657</td>
</tr>
<tr>
<td><strong>Average Realized Sales Price</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil price per Bbl</td>
<td>$ —</td>
<td>$ —</td>
<td>$ —</td>
</tr>
<tr>
<td>Natural gas price per Mcf</td>
<td>$3.90</td>
<td>$2.95</td>
<td>$4.21</td>
</tr>
<tr>
<td>NGL price per Bbl</td>
<td>$ —</td>
<td>$ —</td>
<td>$ —</td>
</tr>
<tr>
<td>Total price per Boe</td>
<td>$23.40</td>
<td>$17.70</td>
<td>$25.26</td>
</tr>
<tr>
<td><strong>Average Unit Cost per Boe</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lease operating expense per Boe</td>
<td>$11.68</td>
<td>$11.51</td>
<td>$11.61</td>
</tr>
<tr>
<td>Production taxes</td>
<td>$1.51</td>
<td>$1.26</td>
<td>$1.65</td>
</tr>
<tr>
<td>Total lease operating expense</td>
<td>$13.19</td>
<td>$12.77</td>
<td>$13.26</td>
</tr>
</tbody>
</table>

(a) There were no NGL sales from our Antrim Shale properties.

(b) The Spraberry Trend properties were acquired in separate transactions that closed on July 2, 2012, December 28, 2012 and December 30, 2013. Production data corresponds to operating results from the acquisition dates through December 31, 2012 and December 31, 2013. During 2012, the Partnership sold its natural gas production from the Spraberry Trend on a wet gas basis under contracts we assumed in the acquisitions.

(c) Postle field was acquired through the Whiting Acquisition in July 2013. Production data corresponds to operating results from the acquisition date through December 31, 2013.

The Antrim Shale, which accounted for 23% of our total estimated proved reserves at December 31, 2013, accounted for 22%, 30% and 38% of our total production and 51%, 54% and 70% of our natural gas production for 2013, 2012 and 2011, respectively. The average realized prices per Mcfe for our Antrim Shale production were $3.90, $2.95 and $4.21 for 2013, 2012 and 2011, respectively. Lease operating expenses per Mcfe for our Antrim Shale production were $1.95, $1.92 and $1.94 for 2013, 2012 and 2011, respectively.

The Spraberry Trend, which accounted for 19% of our total estimated proved reserves at December 31, 2013, accounted for 13% and 4% of our total production for 2013 and 2012, respectively. For the year ended December 31, 2013, the Spraberry Trend’s production accounted for 14% of our total oil, 56% of total NGL and 6% of our total natural gas production. For the year ended December 31, 2012, the Spraberry Trend’s production accounted for 5% of our total oil and 3% of our total natural gas production. The average realized prices per Boe for our Spraberry Trend production were $61.89 and $60.83 for 2013 and 2012. Lease operating expenses per Boe for our Spraberry Trend production were $8.91 and $5.58 for 2013 and 2012.

The Postle Field, which accounted for 19% of our total estimated proved reserves at December 31, 2013, accounted for approximately 10% of our total production since the acquisition date on July 15, 2013. During the year ended December 31, 2013, the Postle Field produced 18% of our total oil, 14% of our total NGL and 1% of our total natural gas production. The average realized price per Boe for our Postle Field production was $87.54. Lease operating expenses per Boe for our Postle Field production was $21.36 per Boe.

**Productive Wells**

The following table sets forth information for our properties as of December 31, 2013 relating to the productive wells in which we owned a working interest. Productive wells consist of producing wells and wells capable of production. Gross wells are the total number of productive wells in which we have an interest, and net wells are the sum of our fractional working interests owned in the gross wells. None of our productive wells have multiple completions.
Developed and Undeveloped Acreage

The following table sets forth information for our properties as of December 31, 2013 relating to our leasehold acreage. Developed acres are acres spaced or assigned to productive wells. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of gas or oil, regardless of whether such acreage contains proved reserves. Gross acres are the total number of acres in which a working interest is owned. Net acres are the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

### Developed Acreage

<table>
<thead>
<tr>
<th>State</th>
<th>Gross</th>
<th>Net</th>
<th>Gross</th>
<th>Net</th>
</tr>
</thead>
<tbody>
<tr>
<td>Michigan</td>
<td>462,171</td>
<td>218,153</td>
<td>41,336</td>
<td>37,197</td>
</tr>
<tr>
<td>Wyoming</td>
<td>161,960</td>
<td>88,013</td>
<td>36,162</td>
<td>13,652</td>
</tr>
<tr>
<td>Indiana</td>
<td>44,240</td>
<td>43,500</td>
<td>3,568</td>
<td>3,534</td>
</tr>
<tr>
<td>Florida</td>
<td>34,402</td>
<td>33,322</td>
<td>8,020</td>
<td>3,268</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>30,097</td>
<td>29,206</td>
<td>160</td>
<td>151</td>
</tr>
<tr>
<td>Colorado</td>
<td>14,292</td>
<td>13,198</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Texas</td>
<td>10,160</td>
<td>8,316</td>
<td>7,853</td>
<td>6,549</td>
</tr>
<tr>
<td>California</td>
<td>3,984</td>
<td>3,154</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Kentucky</td>
<td>3,148</td>
<td>3,148</td>
<td>697</td>
<td>397</td>
</tr>
<tr>
<td>Utah</td>
<td>1,740</td>
<td>529</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>766,194</td>
<td>440,539</td>
<td>97,796</td>
<td>64,748</td>
</tr>
</tbody>
</table>

### Undeveloped Acreage

<table>
<thead>
<tr>
<th>State</th>
<th>Gross</th>
<th>Net</th>
<th>Gross</th>
<th>Net</th>
</tr>
</thead>
<tbody>
<tr>
<td>Michigan</td>
<td>37,197</td>
<td>332</td>
<td>538</td>
<td>2,063</td>
</tr>
<tr>
<td>Wyoming</td>
<td>13,652</td>
<td>1,944</td>
<td>—</td>
<td>2,621</td>
</tr>
<tr>
<td>Texas</td>
<td>6,549</td>
<td>250</td>
<td>—</td>
<td>369</td>
</tr>
<tr>
<td>Indiana</td>
<td>3,534</td>
<td>1,681</td>
<td>—</td>
<td>136</td>
</tr>
<tr>
<td>Florida</td>
<td>3,268</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Kentucky</td>
<td>397</td>
<td>175</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>151</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>64,748</td>
<td>4,382</td>
<td>538</td>
<td>5,189</td>
</tr>
</tbody>
</table>

The following table lists the net undeveloped acres as of December 31, 2013, the net acres expiring in the years ending December 31, 2014, 2015 and 2016, and, where applicable, the net acres expiring that are subject to extension options.

### 2014 Expirations

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Michigan</td>
<td>37,197</td>
<td>332</td>
<td>538</td>
<td>2,063</td>
<td>4,166</td>
</tr>
<tr>
<td>Wyoming</td>
<td>13,652</td>
<td>1,944</td>
<td>—</td>
<td>2,621</td>
<td>—</td>
</tr>
<tr>
<td>Texas</td>
<td>6,549</td>
<td>250</td>
<td>—</td>
<td>369</td>
<td>—</td>
</tr>
<tr>
<td>Indiana</td>
<td>3,534</td>
<td>1,681</td>
<td>—</td>
<td>136</td>
<td>209</td>
</tr>
<tr>
<td>Florida</td>
<td>3,268</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>2,273</td>
</tr>
<tr>
<td>Kentucky</td>
<td>397</td>
<td>175</td>
<td>—</td>
<td>—</td>
<td>209</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>151</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>64,748</td>
<td>4,382</td>
<td>538</td>
<td>5,189</td>
<td>4,166</td>
</tr>
</tbody>
</table>

As of December 31, 2013, we held more than 130,000 net acres in the developing Utica-Collingwood shale play in Michigan. Approximately 85% of this acreage is held by production. As of December 31, 2013, we also held more than 75,000 net acres in the developing A1-Carbonate play in Michigan, approximately 80% of which is held by production.
Drilling Activity

Drilling activity and production optimization projects are on lower risk, development properties. The following table sets forth information for our properties with respect to wells completed during the years ended December 31, 2013, 2012 and 2011. Productive wells are those that produce commercial quantities of oil and gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled during the periods presented.

<table>
<thead>
<tr>
<th></th>
<th>Year Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td><strong>Gross development wells:</strong></td>
<td></td>
</tr>
<tr>
<td>Productive</td>
<td>119</td>
</tr>
<tr>
<td>Dry</td>
<td>3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>122</td>
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<tr>
<td><strong>Net development wells:</strong></td>
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<td>Productive</td>
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<tr>
<td>Dry</td>
<td>3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>108</td>
</tr>
</tbody>
</table>

As of December 31, 2013, we had the following wells in progress: 13 (gross and net) wells in Texas, two (gross and net) wells in California and one (gross and net) well in Florida.

Delivery Commitments

As of December 31, 2013, we had no material delivery commitments.

Sales Contracts

We have a portfolio of oil, NGL and natural gas sales contracts with large, established refiners and utilities. Our sales contracts are sold at market-sensitive or spot prices. Because commodity products are sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. During 2013, our largest purchasers were Phillips 66, which accounted for approximately 15% of our net sales revenues; Shell Trading, which accounted for approximately 15% of our net sales revenues; and Marathon Oil Corporation, which accounted for approximately 10% of our net sales revenues. For the significant customer information for the years ended December 31, 2012 and 2011, see Note 19 to the consolidated financial statements in this report.

Commodity Prices

We analyze the prices we realize from sales of our oil, NGL and natural gas production and the impact on those prices of differences in market-based index prices and the effects of our derivative activities. We market our oil and natural gas production to a variety of purchasers based on regional pricing. The WTI spot price of oil is a widely used benchmark in the pricing of domestic and imported oil in the United States. The relative value of oil is mainly determined by its quality and location. In the case of WTI spot pricing, the oil is light and sweet, meaning that it has a lower specific gravity (lightness) and low sulfur content, and is priced for delivery at Cushing, Oklahoma. In general, higher quality oils (lighter and sweeter) with fewer transportation requirements result in higher realized pricing for producers. Historically there has been a strong relationship between changes in NGL and oil prices. NGL prices are correlated to North American supply and petrochemical demands.

Our Oklahoma oil traded at a discount to WTI spot prices primarily due to transportation and quality and our Oklahoma NGLs traded at a discount due to regional market demand and transportation. Our Texas oil traded at a discount to WTI spot prices due to the deduction of transportation costs and our Texas NGLs traded at a discount due to processing fees, profit sharing and transportation. Our California oil is generally medium gravity crude. Because of its proximity to the extensive Los Angeles refining market, it has traded at only a minor discount to WTI spot price in the past. Historically, WTI spot prices for oil and ICE Brent oil prices have traded with only a narrow margin. Increasing supply into Cushing starting in early 2011 resulted in transportation bottlenecks which have led to divergence in the two major world oil benchmarks that has continued to the present. With the California market largely isolated from Cushing, management believes that ICE Brent pricing will better correlate with local California prices we receive until such time as the transportation infrastructure issues...
at Cushing are resolved. In 2013, ICE Brent prices were higher than WTI spot prices, and our California production traded at a premium to WTI spot prices. Our Wyoming oil, while generally of similar quality to our Los Angeles Basin oil trades at a significant discount to WTI spot price because of its distance from a major refining market and the fact that our central Wyoming production is priced relative to the Western Canadian Select benchmark. Our eastern Wyoming production is priced relative to Flint Hills Resources Wyoming Sweet posting, both of which have historically traded at a significant discount to WTI spot price. Our Florida oil also traded at a discount to WTI spot price primarily because the oil is transported via barge.

In 2013, the WTI spot price averaged approximately $98 per Bbl, compared with about $94 a year earlier. Monthly average WTI spot prices during 2013 ranged from a low of $92 per Bbl in April to a high of $107 per Bbl in August. During 2013, the average differentials per barrel to WTI spot prices were a $8.03 discount for our Oklahoma-based production, a $4.70 discount for our Texas-based production, a $19.67 discount for our Wyoming-based production, a $7.41 premium for our California-based production and a $2.38 discount for our Florida-based production. In 2013, our average NGL realized price was $35.25 per Boe.

Our Michigan properties have favorable natural gas supply and demand characteristics as the state has been importing an increasing percentage of its natural gas. This supply and demand situation has allowed us to sell our natural gas production at a slight premium to Henry Hub spot prices. Our Wyoming natural gas generally trades at a discount to Henry Hub due to its relative location and the regional supply and demand market balances. Prices for natural gas have historically fluctuated widely and in many regional markets are aligned with supply and demand conditions in regional markets and with the overall U.S. market. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage relative to customer demand. U.S. natural gas prices are also typically higher during the winter period when demand for heating is greatest. During 2013, the monthly average Henry Hub spot price ranged from a low of $3.33 per MMBtu in February to a high of $4.23 per MMBtu in December. During 2013, the Henry Hub spot price averaged approximately $3.73 per MMBtu and the differentials per Mcf to the Henry Hub spot price were a $0.19 premium for our Michigan-based production, a $0.09 premium for our Wyoming-based production and a $0.45 discount for our Texas-based production. See Part I—Item 1A “—Risk Factors” — “Risks Related to Our Business — Oil, NGL and natural gas prices and differentials are highly volatile. In the past, declines in commodity prices have adversely affected, and in the future will adversely affect, our financial condition and results of operations, cash flow, access to the capital markets and ability to grow. A decline in our cash flow could force us to reduce our distributions or cease paying distributions altogether in the future. — Natural gas prices have declined substantially since 2008 and are expected to remain depressed for the foreseeable future. Approximately 43% of our 2013 production, on an MBoe basis, was natural gas. Sustained depressed prices of natural gas will adversely affect our assets, development plans, results of operations and financial position, perhaps materially. — Low natural gas prices, a future decline in oil prices and concern about the global financial markets could limit our ability to obtain funding in the capital and credit markets on terms we find acceptable, obtain additional or continued funding under our credit facility or obtain funding at all.” in this report.

Our operating expenses are responsive to changes in commodity prices. We experience pressure on operating expenses that is highly correlated to oil prices for specific expenditures such as lease fuel, electricity, drilling services and severance and minerals-based property taxes.

**Derivative Activity**

Our revenues and net income are sensitive to oil and natural gas prices. We enter into various derivative contracts intended to achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas. We currently maintain derivative arrangements for a significant portion of our oil and gas production. Currently, we use a combination of fixed price swap and option arrangements to economically hedge NYMEX WTI and ICE Brent oil prices and Henry Hub and MichCon City-Gate natural gas prices. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing oil and natural gas prices on our cash flow from operations for those periods. While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow and distributions, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected. For a more detailed discussion of our derivative activities, see Part II—Item 7A “—Quantitative and Qualitative Disclosures About Market Risk” and Note 4 to the consolidated financial statements included in this report.
Compliance with regulatory requirements; the oil and gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in all aspects of our business, including acquiring properties and oil and gas leases, marketing oil and gas, contracting for drilling rigs and other equipment necessary for drilling and completing wells and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit.

In regards to the competition we face for drilling rigs and the availability of related equipment, the oil and gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel in the past, which has delayed development drilling and other exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program. Competition is also strong for attractive oil and gas producing properties, undeveloped leases and drilling rights, which may affect our ability to compete satisfactorily when attempting to make further acquisitions. See Item 1A “—Risk Factors” — “Risks Related to Our Business — We may be unable to compete effectively with other companies in the oil and gas industry, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders” in this report.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. Prior to completing an acquisition of producing oil leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Under our credit facility, we have granted the lenders a lien on substantially all of our oil and gas properties. Our properties are also subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Some of our oil and gas leases, easements, rights-of-way, permits, licenses and franchise ordinances require the consent of the current landowner to transfer these rights, which in some instances is a governmental entity. We believe that we have obtained sufficient third party consents, permits and authorizations for us to operate our business in all material respects. With respect to any consents, permits or authorizations that have not been obtained, we believe that the failure to obtain these consents, permits or authorizations have no material adverse effect on the operation of our business.

Seasonal Nature of Business

Seasonal weather conditions, especially freezing conditions in Michigan and Wyoming, and lease stipulations can limit our drilling activities and other operations in certain of the areas in which we operate, and, as a result, we seek to perform the majority of our drilling during the non-winter months. These seasonal anomalies can pose challenges for meeting our well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Environmental Matters and Regulation

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the emission and discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before exploration, drilling or production activities commence;
- prohibit some or all of the operations of facilities deemed in non-compliance with regulatory requirements;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits, plug abandoned wells and restore drilling sites.
These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the United States Congress (“Congress”), state legislatures and federal and state agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

**Waste Handling.** The Resource Conservation and Recovery Act (“RCRA”), and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the U.S. Environmental Protection Agency (“EPA”), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or natural gas are currently regulated under RCRA’s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

**Hazardous Substances.** The Comprehensive Environmental Response, Compensation and Liability Act, (“CERCLA”), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Despite the “petroleum exclusion” of Section 101(14) of CERCLA, which currently encompasses oil and natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

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

**Water Discharges.** The Federal Water Pollution Control Act (the “Clean Water Act”) and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The Clean Water Act also imposes spill prevention, control, and countermeasure requirements, including requirements for appropriate containment berms and similar structures, to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.
The primary federal law for oil spill liability is the Oil Pollution Act (“OPA”) which establishes a variety of requirements pertaining to oil spill prevention, containment, and cleanup. OPA applies to vessels, offshore facilities and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, are required to develop and implement plans for preventing and responding to oil spills and, if a spill occurs, may be subject to oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from the spill.

**Underground Injection Control (UIC).** The Safe Drinking Water Act and comparable state laws regulate the injection of produced water, steam, or carbon dioxide into underground reservoirs for enhanced oil recovery or disposal. Under the UIC Program, producers must obtain federal or state Class II injection well permits and routinely monitor and report fluid volumes, pressures, and chemistry, and conduct mechanical integrity tests on injection wells.

**Air Emissions.** The Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. For example, in August 2012, the EPA adopted new rules that establish new air emission control requirements for oil and natural gas production and natural gas processing operations. The new rules include New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The new regulations require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of “green completions” for hydraulic fracturing, which requires the operator to recover or treat rather than vent the gas and NGLs that come to the surface during completion of the fracturing process. The rules also establish specific requirements regarding emissions from new or modified compressors, dehydrators, storage tanks, and other production equipment. In addition, the rules establish new leak detection requirements for new or modified natural gas processing plants. Compliance with these rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. States can also impose air emissions limitations that are more stringent than the federal standards imposed by the EPA, and California air quality laws and regulations are in many instances more stringent than comparable federal laws and regulations. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Regulatory requirements relating to air emissions are particularly stringent in Southern California. Rules restricting air emissions may require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

**Hydraulic Fracturing.** Hydraulic fracturing involves the injection of water, sand, and chemicals under pressure into dense subsurface rock formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel, and in April 2012, the EPA adopted regulations requiring the reduction of volatile organic compound emissions from oil and natural gas production facilities by mandating the use of “green completions” for hydraulic fracturing activities, which requires the operator to recover rather than vent gas and NGLs that return to the surface during well completion operations. At the state level, several states, including California, Texas, and Wyoming, have adopted and/or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on water resources. The EPA’s study includes 18 separate research projects addressing topics such as water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and disposal. EPA has indicated that it expects to issue its study report in late 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their findings, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such
requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

**Global Warming and Climate Change.** In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

California has been one of the leading states in adopting greenhouse gas emission reduction requirements, and California’s cap and trade program’s first compliance period began in 2012. California’s cap and trade program requires us to report our greenhouse gas emissions and essentially sets maximum limits or caps on total emissions of greenhouse gases from all industrial sectors that are or become subject to the cap and trade program due to the levels of greenhouse gases that are emitted. This includes the oil and natural gas extraction sector of which we are a part. Our main sources of greenhouse gas emissions for our Southern California oil and gas operations are primarily attributable to emissions from internal combustion engines powering generators to produce electricity, flares for the disposal of excess field gas, and fugitive emission from equipment such as tanks and components. Under the California program, the cap will decline annually from 2013 through 2020. We will be required to obtain compliance instruments for each metric ton of greenhouse gases that we emit in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. A portion of the allowance will be granted by the state, but any shortfall between the state-granted allowance and the facility’s emissions will have to be addressed through the purchase of additional allowances either from the state or a third party. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. However, we do not expect the cost to be material to our operations.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Such climatic events could have an adverse effect on our financial condition and results of operations.

**Pipeline Safety.** Some of our pipelines are subject to regulation by the U.S. Department of Transportation (“DOT”) and analogous state agencies in some cases under the Pipeline Safety Improvement Act of 2002, which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The DOT, through the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect “high consequence areas.” “High consequence areas” are currently defined to include areas with specified population densities, buildings containing populations with limited mobility, areas where people may gather along the route of a pipeline (such as athletic fields or campgrounds), environmentally sensitive areas and commercially navigable waterways. Under the DOT’s regulations, integrity management programs are required to include baseline assessments to identify potential threats to each pipeline segment, implementation of mitigation measures to reduce the risk of pipeline failure, periodic reassessments, reporting and record keeping. In two steps taken in 2008 and 2010, PHMSA extended its integrity management program requirements to hazardous liquid gathering lines located in “unusually sensitive areas,” such
as locations containing sole-source drinking water aquifers, endangered species or other protected ecological resources. Fines and penalties may be imposed on pipeline operators that fail to comply with PHMSA requirements, and such operators may also become subject to orders or injunctions restricting pipeline operations. We have had fines and penalties imposed or threatened based on claimed paperwork and documentation omissions.

**OSHA and Other Laws and Regulation.** We are subject to the requirements of the federal Occupational Safety and Health Act, ("OSHA"), and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, OSHA Process Safety Management, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse effect on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2013. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2014. However, accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. In addition, we expect to be required to incur remediation costs for property, wells and facilities at the end of their useful lives. Moreover, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our business, financial condition and results of operations or ability to make distributions to our unitholders.

**Other Regulation of the Oil and Gas Industry**

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

**Production Regulation.** Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate, also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

The various states regulate the drilling for, and the production of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Wyoming currently imposes a severance tax on oil and gas producers at the rate of 6% of the value of the gross product extracted. Wyoming wells that reside on Native American or federal land are subject to an additional tax of 8.5%. Florida currently imposes a severance tax on oil producers of up to 8%, and Michigan currently imposes a severance tax on oil producers at the rate of 7.4% and on gas producers at the rate of 5.8%. In Wyoming, Florida and Michigan, reduced rates may apply to certain types of wells and production methods, such as new wells, renewed wells, stripper production and tertiary production. California does not currently impose a severance tax but taxes minerals in place. Attempts by California to impose a similar tax have been introduced in the past.

States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production.
allowances from oil and gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill. Our Los Angeles Basin properties are located in urbanized areas, and certain drilling and development activities within these fields require local zoning and land use permits obtained from individual cities or counties. These permits are discretionary and, when issued, usually include mitigation measures which may impose significant additional costs or otherwise limit development opportunities.

Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act (“NGA”) exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission (“FERC”) as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, and, therefore, the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our natural gas gathering operations are subject to regulation in the various states in which we operate. The level of such regulation varies by state. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Transportation Pipeline Regulation. Our sole interstate natural gas pipeline is an 8.3 mile pipeline in Kentucky that connects with the Texas Gas Transmission interstate pipeline. That pipeline is subject to a limited jurisdiction FERC certificate, and we are not currently required to maintain a tariff at FERC. Our intrastate natural gas transportation pipelines are subject to regulation by applicable state regulatory commissions. The level of such regulation varies by state. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

We also own a 51 mile oil pipeline in Oklahoma that connects with Texas that is a common carrier and subject to regulation by FERC under the October 1, 1977 version of the Interstate Commerce Act (“ICA”) and the Energy Policy Act of 1992 (“EPAct 1992”). The ICA and its implementing regulations give FERC authority to regulate the rates charged for service on the interstate common carrier liquids pipelines and generally require the rates and practices of interstate liquids pipelines to be just and reasonable and nondiscriminatory. The ICA also requires these pipelines to keep tariffs on file with FERC that set forth the rates the pipeline charges for providing transportation services and the rules and regulations governing these services. EPAct 1992 and its implementing regulations allow interstate common carrier oil pipelines to annually index their rates up to a prescribed ceiling level. FERC retains cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach.

Natural Gas Processing Regulation. Our natural gas processing operations are not presently subject to FERC regulation. There can be no assurance that our processing operations will continue to be exempt from other FERC regulation in the future.

Our processing facilities are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and in state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to our processing operations.

Regulation of Sales of Oil, Natural Gas and NGLs. The price at which we buy and sell oil, natural gas and NGLs is currently not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC, the Commodity Futures Trading Commission (“CFTC”) and the Federal Trade Commission (“FTC”), as further described below. Should we violate
the anti-market manipulation laws and regulations, we could be subject to fines and penalties as well as related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the CFTC to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to liquids swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to liquids purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation. For a description of FERC’s anti market manipulation rules, see “Energy Policy Act of 2005” below.

Our sales of oil, natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation can be subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of oil and NGLs. These initiatives also may indirectly affect the intrastate transportation of oil, natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to our oil, natural gas and NGL marketing operations, and we do not believe that we would be affected by any such FERC action materially differently than other oil, natural gas and NGL marketers with whom we compete.

**Energy Policy Act of 2005**. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 (“EPAct 2005”). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. With respect to regulation of natural gas transportation, EPAct 2005 amended the NGA and the Natural Gas Policy Act (“NGPA”) by increasing the criminal penalties available for violations of each Act. EPAct 2005 also added a new section to the NGA, which provides FERC with the power to assess civil penalties of up to $1,000,000 per day for each violation of the NGA and increased FERC’s civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in FERC-jurisdictional transportation and the sale for resale of natural gas in interstate commerce. EPAct 2005 also amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of EPAct 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which they were made, not misleading; or (3) engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity. The new anti-market manipulation rule does not apply to activities that relate only to non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, including the annual reporting requirements under Order No. 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC’s enforcement authority. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts.

**FERC Market Transparency Rules**. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers, and natural gas producers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC’s policy statement on price reporting.

**Employees**

BreitBurn Management, our wholly-owned subsidiary, operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. All of our employees, including our executives, are employees of BreitBurn Management. As of December 31, 2013, BreitBurn Management had 563 full time employees. BreitBurn Management provides services to us as well as to our Predecessor. None of our
employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Offices

BreitBurn Management’s principal executive offices are located at 515 South Flower Street, Suite 4800, Los Angeles, California 90071. BreitBurn Management leases office space in the JP Morgan Chase Tower at 600 Travis Street, Houston, Texas 77002.

Financial Information

We operate our business as a single segment. Additionally, all of our properties are located in the United States and all of the related revenues are derived from purchasers located in the United States. Our financial information is included in the consolidated financial statements and the related notes beginning on page F-1.
Item 1A. Risk Factors.

An investment in our securities is subject to certain risks described below. If any of these risks were actually to occur, our business, financial condition and results of operations could be materially adversely affected. In that case, we might not be able to pay the distributions on our Common Units, the trading price of our Common Units could decline and you could lose part or all of your investment.

Risks Related to Our Business

Oil, NGL and natural gas prices and differentials are highly volatile. In the past, declines in commodity prices have adversely affected, and in the future will adversely affect, our financial condition and results of operations, cash flow, access to the capital markets and ability to grow. A decline in our cash flow could force us to reduce our distributions or cease paying distributions altogether in the future.

The oil, NGL and natural gas markets are highly volatile, and we cannot predict future oil and natural gas prices. Prices for oil, NGL and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, NGLs and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and foreign supply of and demand for oil, NGLs and natural gas;
- market prices of oil, NGLs and natural gas;
- level of consumer product demand;
- weather conditions;
- overall domestic and global political and economic conditions;
- political and economic conditions in producing countries, including those in the Middle East, Russia, South America and Africa;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- impact of the U.S. dollar exchange rates on commodity prices;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- impact of energy conservation efforts;
- capacity, cost and availability of oil and natural gas pipelines, processing, gathering and other transportation facilities and the proximity of these facilities to our wells;
- increase in imports of liquid natural gas in the United States; and
- price and availability of alternative fuels.

Oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because natural gas accounted for approximately 40% of our estimated proved reserves as of December 31, 2013 and approximately 43% of our 2013 production on an MBoe basis, our financial results will be sensitive to movements in natural gas prices.

In the past, prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2013, the monthly average WTI spot price ranged from a low of $92 per Bbl in April to a high of $107 per Bbl in August while the monthly average Henry Hub natural gas price ranged from a low of $3.33 per MMBtu in February to a high of $4.23 per MMBtu in December.

Price discounts or differentials between WTI spot prices and what we actually receive are also historically very volatile. For instance, during calendar year 2013, the average quarterly premium to WTI spot prices for our California production varied from $0.91 to $16.50 per Bbl, with the differential percentage of the total price per Bbl ranging from 1% to 18%. For Wyoming oil, our average quarterly price discount from WTI spot varied from $13.31 to $26.42, with the discount percentage ranging from 13% to 27% of the total price per Bbl. For Florida oil, our average quarterly differential to WTI spot prices varied from a $8.20 discount to a $6.39 premium, excluding transportation expenses, with the differential percentage ranging from a 8% discount to a 7% premium of the total price per Bbl.
Our revenue, profitability and cash flow depend upon the prices and demand for oil, NGLs and natural gas, and a drop in prices could significantly affect our financial results and impede our growth. In particular, continuation of the current low natural gas price environment, further declines in natural gas prices, lack of natural gas storage or a significant decline in oil prices will negatively impact:

- our ability to pay distributions;
- the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically;
- the amount of cash flow available for capital expenditures;
- our ability to replace our production and future rate of growth;
- our ability to borrow money or raise additional capital and our cost of such capital;
- our ability to meet our financial obligations; and
- the amount that we are allowed to borrow under our credit facility.

Historically, higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling equipment, crews and associated supplies, equipment and services. Accordingly, continued high costs could adversely affect our ability to pursue our drilling program and our results of operations.

In the past, we have raised our distribution levels on our Common Units in response to increased cash flow during periods of relatively high commodity prices. However, we were not able to sustain those distribution levels during subsequent periods of lower commodity prices. For example, we did not pay a distribution from February 2009 until May 2010. Although distributions were reinstated in 2010, a decline in our cash flow may force us to reduce our distributions or cease paying distributions again altogether in the future.

**Natural gas prices have declined substantially since 2008 and are expected to remain depressed for the foreseeable future.**
Approximately 43% of our 2013 production, on an MBoe basis, was natural gas. Sustained depressed prices of natural gas will adversely affect our assets, development plans, results of operations and financial position, perhaps materially.

Natural gas prices have declined from an average price at Henry Hub of $8.86 per MMBtu in 2008 to $3.73 per MMBtu in 2013. The reduction in prices has been caused by many factors, including increases in gas production from non-conventional (shale) reserves, warmer than normal weather and high levels of natural gas in storage. As of December 31, 2013, we had hedged more than 72% of our expected natural gas production in 2014 at prices higher than those currently prevailing. However, if prices for natural gas continue to remain depressed for lengthy periods, we will be required to write down the value of our oil and natural gas properties and/or revise our development plans which may cause certain of our undeveloped well locations to no longer be deemed proved. In addition, sustained low prices for natural gas will reduce the amounts we would otherwise have available to pay expenses, make distributions to our unitholders and service our indebtedness.

**Low natural gas prices, a future decline in oil prices and concern about the global financial markets could limit our ability to obtain funding in the capital and credit markets on terms we find acceptable, obtain additional or continued funding under our credit facility or obtain funding at all.**

Low natural gas prices, a future decline in oil prices and concern about the global financial markets could make it challenging to obtain funding in the capital and credit markets in the future. During 2012 and 2013, we were able to access the debt and equity capital markets. However, future decline in oil or natural gas prices could significantly increase the cost of obtaining money in the capital and credit markets and limit our ability to access those markets as a source of funding in the future.

Historically, we have used our cash flow from operations, borrowings under our credit facility and issuances of senior notes and additional partnership units to fund our capital expenditures and acquisitions. Any future decline in oil prices could ultimately decrease our net revenue and profitability. Lower natural gas prices could negatively impact our revenues and cash flows.

These events affect our ability to access capital in a number of ways, which include the following:
Due to these factors, we cannot be certain that funding will be available, if needed and to the extent required, on acceptable terms. If funding is not available when needed, or if funding is available only on unfavorable terms, we may be unable to meet our obligations as they come due or be required to post collateral to support our obligations, or we may be unable to implement our development plans, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues, results of operations, financial condition or ability to pay distributions. Moreover, if we are unable to obtain funding to make acquisitions of additional properties containing proved oil or natural gas reserves, our total level of estimated proved reserves may decline as a result of our production, and we may be limited in our ability to maintain our level of cash distributions.

The production from our Oklahoma properties could be adversely affected by the cessation or interruption of the supply of CO₂ to those properties.

We use enhanced recovery technologies to produce oil and natural gas. For example, we inject water and CO₂ into formations on substantially all of our Oklahoma properties to increase production of oil and natural gas. The additional production and reserves attributable to the use of enhanced recovery methods are inherently difficult to predict. If we are unable to produce oil and gas by injecting CO₂ in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO₂ to enhance production is subject to our ability to obtain sufficient quantities of CO₂. If, under our CO₂ supply contracts, the supplier is unable to deliver its contractually required quantities of CO₂ to us, or if our ability to access adequate supplies is impeded, then we may not have sufficient CO₂ to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes will be negatively impacted.

Even if we are able to pay distributions on our Common Units under the terms of our credit facility, we may not elect to pay distributions on our Common Units because we do not have sufficient cash flow from operations following establishment of cash reserves, reduction of debt and payment of fees and expenses.

Our credit facility restricts our ability to make distributions to unitholders or repurchase units unless after giving effect to such distribution or repurchase, we remain in compliance with all terms and conditions of our credit facility. For example, we were restricted from declaring a distribution on our Common Units and did not pay a distribution from February 2009 until May 2010. While we currently are not restricted by our credit facility from declaring a distribution, we could be restricted from paying a distribution in the future.

Even if we are able to pay distributions on our Common Units under the terms of our credit facility, we may not have sufficient available cash each quarter to pay distributions on our Common Units. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses, debt reduction and the amount of any cash reserve amounts that our General Partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. In the future, we may reserve a substantial portion of our cash generated from operations to develop our oil and natural gas properties and to acquire additional oil and natural gas properties in order to maintain and grow our level of oil and natural gas reserves.

The amount of cash that we actually generate will depend upon numerous factors related to our business that may be beyond our control, including among other things:
• the amount of oil and natural gas we produce;
• demand for and prices at which we sell our oil and natural gas;
• the effectiveness of our commodity price derivatives;
• the level of our operating costs;
• prevailing economic conditions;
• our ability to replace declining reserves;
• continued development of oil and natural gas wells and proved undeveloped reserves;
• our ability to acquire oil and natural gas properties from third parties in a competitive market and at an attractive price;
• the level of competition we face;
• fuel conservation measures;
• alternate fuel requirements;
• government regulation and taxation; and
• technical advances in fuel economy and energy generation devices.

In addition, the actual amount of cash that we will have available for distribution will depend on other factors, including:

• our ability to borrow under our credit facility to pay distributions;
• debt service requirements and restrictions on distributions contained in our credit facility or future debt agreements;
• the level of our capital expenditures;
• sources of cash used to fund acquisitions;
• fluctuations in our working capital needs;
• general and administrative expenses (“G&A”);
• cash settlement of hedging positions;
• timing and collectability of receivables; and
• the amount of cash reserves established for the proper conduct of our business.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please read Part II—Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources” in this report.

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

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

• we cannot identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
• we cannot obtain financing for these acquisitions on economically acceptable terms;
• we are outbid by competitors; or
• our Common Units are not trading at a price that would make the acquisition accretive.

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

Any acquisitions that we complete are subject to substantial risks that could reduce our ability to make distributions to our unitholders. The integration of the oil and natural gas properties that we acquire may be difficult and could divert our management’s attention away from our other operations.

If we do make acquisitions that we believe will increase available cash per unit, these acquisitions may nevertheless result in a decrease in available cash per unit. Any acquisition involves potential risks, including, among other things: 29
Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. 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 assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Drilling for and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our financial condition and results of operations and, as a result, our ability to pay distributions to our unitholders.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough oil and natural gas to be commercially viable after drilling, operating and other costs. Furthermore, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including, among other things:

- high costs, shortages or delivery delays of drilling rigs, equipment, labor or other services;
- unexpected operational events and drilling conditions;
- reductions in oil and natural gas prices;
- limitations in the market for oil and natural gas;
- problems in the delivery of oil and natural gas to market;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;
- pipe or cement failures;
- casing collapses;
- compliance with environmental and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in formations;
- fires, blowouts, surface craterings and explosions;
If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

**We may be unable to compete effectively with other companies in the oil and gas industry, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.**

The oil and gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major independent oil and gas companies and possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties and available funds. Many of our larger competitors not only drill for and produce oil and gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and gas industry. Other companies may have a greater ability to continue drilling activities during periods of low oil and gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with other companies could have a material adverse effect on our business activities, financial condition and results of operations.

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

As of February 27, 2014, we had approximately $747.0 million in borrowings outstanding under our credit facility. Our credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base is redetermined semi-annually, and the available borrowing amount could be further decreased as a result of such redeterminations. Decreases in the available borrowing amount could result from declines in oil and natural gas prices, operating difficulties or increased costs, declines in reserves, lending requirements or regulations or certain other circumstances. Currently, our borrowing base for our credit facility is $1.5 billion, and the aggregate commitment of all lenders is $1.4 billion with the ability to increase our total commitments up to the $1.5 billion borrowing base upon lender approval. Our next borrowing base redetermination is scheduled for April 2014. In the event of a substantial decline in commodity prices, our borrowing base could be decreased by the lenders under our credit facility. A future decrease in our borrowing base could be substantial and could be to a level below our outstanding borrowings at that time. Outstanding borrowings in excess of the borrowing base are required to be repaid in five equal monthly payments, or we are required to pledge other oil and natural gas properties as additional collateral, within 30 days following notice from the administrative agent of the new or adjusted borrowing base. If we do not have sufficient funds on hand for repayment, we may be required to seek a waiver or amendment from our lenders, refinance our credit facility or sell assets, debt or Common Units. We may not be able to obtain such financing or complete such transactions on terms acceptable to us or at all. Failure to make the required repayment could result in a default under our credit facility, which could adversely affect our business, financial condition and results of operations.

The operating and financial restrictions and covenants in our credit facility restrict, and any future financing agreements likely will restrict, our ability to finance future operations or capital needs or to engage, expand or pursue our business activities or to pay distributions. Our credit facility restricts, and any future credit facility likely will restrict, our ability to:

- incur indebtedness;
Our credit facility restricts our ability to make distributions to unitholders or repurchase Common Units unless after giving effect to such distribution or repurchase, we remain in compliance with all terms and conditions of our credit facility. While we currently are not restricted by our credit facility from declaring a distribution, we may be restricted from paying a distribution in the future.

We also are required to comply with certain financial covenants and ratios under the credit facility. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. In light of low natural gas prices, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit facility, a significant portion of our indebtedness may become immediately due and payable, our ability to make distributions will be inhibited and our lenders’ commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit facility, the lenders can seek to foreclose on our assets.

See Part II—Item 7 “—Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources” in this report for a discussion of our credit facility covenants.

**Restrictive covenants under our indenture governing our senior notes may adversely affect our operations.**

The indentures governing our $305 million unsecured 8.625% senior notes maturing October 15, 2020 (the “2020 Senior Notes”) and $850 million unsecured 7.875% senior notes maturing April 15, 2022 (the “2022 Senior Notes”) (together, the “Senior Notes”) contain, and any future indebtedness we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our restricted subsidiaries;
- pay distributions on, redeem or repurchase our units or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

A failure to comply with the covenants in the indenture governing our senior notes or any future indebtedness could result in an event of default under the indenture governing the Senior Notes or the future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. In addition, complying with these covenants may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.
Our debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of February 27, 2014, our long-term debt totaled $1.9 billion. Our existing and future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on terms acceptable to us;
- covenants in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our access to the capital markets may be limited;
- our borrowing costs may increase;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

We will require substantial capital expenditures to replace our production and reserves, which will reduce our cash available for distribution. We may be unable to obtain needed capital due to our financial condition, which could adversely affect our ability to replace our production and estimated proved reserves.

To fund our capital expenditures, we will be required to use cash generated from our operations, additional borrowings or the issuance of additional partnership interests, or some combination thereof. In 2014, our oil and gas capital spending program is expected to be between $325 million and $345 million, compared to approximately $295 million in 2013 and approximately $153 million in 2012. We expect to use cash generated from operations to partially fund future capital expenditures, which will reduce cash available for distribution to our unitholders. In the future, our ability to borrow and to access the capital and credit markets may be limited by our financial condition at the time of any such financing or offering and the covenants in our debt agreements, as well as by oil and natural gas prices, the value and performance of our equity securities, and adverse market conditions resulting from, among other things, general economic conditions and contingencies and uncertainties that are beyond our control. Our failure to obtain the funds for necessary future capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay distributions. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional partnership interests may result in significant unitholder dilution, thereby increasing the aggregate amount of cash required to maintain the then-current distribution rate, which could have a material adverse effect on our ability to pay distributions at the then-current distribution rate.

Our inability to replace our reserves could result in a material decline in our reserves and production, which could adversely affect our financial condition. We are unlikely to be able to sustain or increase distributions without making accretive acquisitions or capital expenditures that maintain or grow our asset base.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary based on reservoir characteristics and other factors. The rate of decline of our reserves and production included in our reserve report at December 31, 2013 will change if production from our existing wells declines in a different manner than we have estimated and may change when we drill additional wells, make acquisitions and under other circumstances. Our future
oil and natural gas reserves and production and our cash flow and ability to make distributions depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations and reduce cash available for distribution.

We are unlikely to be able to sustain or increase distributions without making accretive acquisitions or capital expenditures that maintain or grow our asset base. We will need to make substantial capital expenditures to maintain and grow our asset base, which will reduce our cash available for distribution. Because the timing and amount of these capital expenditures fluctuate each quarter, we expect to reserve cash each quarter to finance these expenditures over time. We may use the reserved cash to reduce indebtedness until we make the capital expenditures.

Over a longer period of time, if we do not set aside sufficient cash reserves or make sufficient expenditures to maintain our asset base, we will be unable to pay distributions at the current level from cash generated from operations and would therefore expect to reduce our distributions. If we do not make sufficient growth capital expenditures, we will be unable to sustain our business operations and therefore will be unable to maintain our current level of distributions. With our reserves decreasing, if we do not reduce our distributions, then a portion of the distributions may be considered a return of part of your investment in us as opposed to a return on your investment. Also, if we do not make sufficient growth capital expenditures, we will be unable to expand our business operations and will therefore be unable to raise the level of future distributions.

**Future oil and natural gas price declines may result in a write-down of our asset carrying values.**

Accounting rules require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties in the event we have impairments. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore requires a write-down. During the year ended December 31, 2013, we recorded non-cash impairment charges of approximately $54.4 million. The impairment charges during 2013 were primarily due to $28.3 million of impairment charges to our Michigan non-Antrim oil and gas properties due to negative reserve adjustments due to lower performance and a decrease in expected future commodity prices, and $25.3 million of impairments to an oil property in our Bighorn Basin in Northern Wyoming due to a negative reserve adjustment due to lower performance and a decrease in expected future oil prices. Decreased drilling activity in Michigan was also a factor as the Partnership continues to allocate its capital expenditures more towards liquids-rich areas. Continuing to focus our drilling efforts on liquids could lead to further impairments in our natural gas properties in the future. During the year ended December 31, 2012, we recorded impairments of approximately $12.3 million primarily related to uneconomic proved properties in Michigan, Indiana and Kentucky due to a decrease in expected future natural gas prices. During the year ended December 31, 2011, we recorded impairments of approximately $0.6 million related to uneconomic proved properties in Michigan primarily due to a decrease in expected future natural gas prices.

We also may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our credit facility, which in turn may adversely affect our ability to make cash distributions to our unitholders.

**Our derivative activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders. To the extent we have hedged a significant portion of our expected production and actual production is lower than expected or the costs of goods and services increase, our profitability would be adversely affected.**

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently and may in the future enter into derivative arrangements for a significant portion of our expected oil and natural gas production that could result in both realized and unrealized commodity derivative losses. As of February 27, 2014, we had hedged, through swaps, options (including collar instruments) and physical contracts, approximately 76% of our expected 2014 production.
The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. The reference prices of the derivative instruments we utilize may differ significantly from the actual oil and natural gas prices we realize in our operations. Furthermore, we have adopted a policy that requires, and our credit facility also mandates, that we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we will continue to have direct commodity price exposure on the portion of our production volumes not covered by these derivative transactions.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution in our profitability and liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our derivative activities are subject to the following risks:

- we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions;
- a counterparty may not perform its obligation under the applicable derivative instrument or seek bankruptcy protection;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

As of February 27, 2014, our derivative counterparties were Barclays Bank PLC, Bank of Montreal, Citibank, N.A, Credit Suisse Energy LLC, Union Bank N.A, Wells Fargo Bank National Association, JP Morgan Chase Bank N.A., The Royal Bank of Scotland plc, The Bank of Nova Scotia, BNP Paribas, U.S. Bank National Association, Toronto-Dominion Bank and Royal Bank of Canada. We periodically obtain credit default swap information on our counterparties. As of December 31, 2013 and February 27, 2014, each of these financial institutions had an investment grade credit rating. Although we currently do not believe that we have a specific counterparty risk with any party, our loss could be substantial if any of these parties were to default. As of December 31, 2013, our largest derivative asset balances were with Wells Fargo Bank National Association, Credit Suisse Energy LLC and Citibank, N.A., which accounted for approximately 30%, 26% and 13% of our derivative asset balances, respectively.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

On July 21, 2010, new comprehensive financial reform legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank”) was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Partnership, that participate in that market. Dodd-Frank requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing Dodd-Frank. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012. Certain bona fide hedging transactions would be exempt from these position limits. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.
The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception to the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, Dodd-Frank requires that regulators establish margin rules for uncleared swaps. Rules that require end-users to post initial or variation margin could impact our liquidity and reduce cash available for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules for uncleared swaps are not yet final and their impact on us is not yet clear.

Dodd-Frank may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as credit worthy as the current counterparty. In addition, Dodd-Frank was intended, in part, to reduce the volatility of oil and gas prices. To the extent they are unhedged, our revenues could be adversely affected if a consequence of Dodd-Frank and implementing regulations is to lower commodity prices.

The full impact of Dodd-Frank and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. Dodd-Frank and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of some derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less credit worthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make distributions to our unitholders. Any of these consequences could have a material, adverse effect on us, our financial condition, our results of operations and our ability to make distributions to our unitholders.

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

It is not possible to measure underground accumulations of oil or natural gas in an exact way. Oil and gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. Our independent reserve engineers do not independently verify the accuracy and completeness of information and data furnished by us. In estimating our level of oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- future oil and natural gas prices;
- production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation;
- the accuracy and reliability of the underlying engineering and geologic data; and
- the availability of funds.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly. For example, if the SEC prices used for our December 31, 2013 reserve report had been $10.00 less per Bbl and $1.00 less per MMBtu, respectively, then the standardized measure of our estimated proved reserves as of December 31, 2013 would have decreased by $1.7 billion, from $3.2 billion, to $1.5 billion.
Our standardized measure is calculated using unhedged oil prices and is determined in accordance with SEC rules and regulations. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual drilling and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures.

The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the actual prices we receive for oil and natural gas;
- our actual operating costs in producing oil and natural gas;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with the FASB Accounting Standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

**Our actual production could differ materially from our forecasts.**

From time to time, we provide forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells. In addition, our forecasts assume that none of the risks associated with our oil and gas operations summarized in this Item 1A occur, such as facility or equipment malfunctions, adverse weather effects, or significant declines in commodity prices or material increases in costs, which could make certain production uneconomical.

**In 2013, we depended on three customers for a substantial amount of our sales. If these customers reduce the volumes of oil and natural gas that they purchase from us, our revenue and cash available for distribution will decline to the extent we are not able to find new customers for our production. In addition, if the parties to our purchase contracts default on these contracts, we could be materially and adversely affected.**

In 2013, three customers accounted for approximately 40% of our net sales revenues. If these customers reduce the volumes of oil and natural gas that they purchase from us and we are not able to find new customers for our production, our revenue and cash available for distribution will decline. In 2013, Phillips 66 accounted for approximately 15% of our net sales revenues, Shell Trading accounted for approximately 15% of our net sales revenues and Marathon Oil Corporation accounted for approximately 10% of our net sales revenues.

Natural gas purchase contracts account for a significant portion of revenues relating to our Michigan, Indiana and Kentucky properties. We cannot assure you that the other parties to these contracts will continue to perform under the contracts. If the other parties were to default after taking delivery of our natural gas, it could have a material adverse effect on our cash flows for the period in which the default occurred. A default by the other parties prior to taking delivery of our natural gas could also have a material adverse effect on our cash flows for the period in which the default occurred depending on the prevailing market prices of natural gas at the time compared to the contractual prices.
We have limited control over the activities on properties we do not operate.

On a net production basis, we operated approximately 86% of our production in 2013. We have limited ability to influence or control the operation or future development of the non-operated properties in which we have interests or the amount of capital expenditures that we are required to fund for their operation. The success and timing of drilling development or production activities on properties operated by others depend upon a number of factors that are outside of our control, including the timing and amount of capital expenditures, the operator’s expertise and financial resources, approval of other participants, and selection of technology. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns on capital or lead to unexpected future costs.

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

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

We currently possess property and general liability insurance at levels that we believe are appropriate; however, we are not fully insured for these items and insurance against all operational risk is not available to us. We are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets after natural disasters and terrorist attacks have made it more difficult for us to obtain certain types of coverage. There can be no assurance that we will be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes or that the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to you.

If third party pipelines and other facilities interconnected to our wells and gathering and processing facilities become partially or fully unavailable to transport natural gas, oil or NGLs, our revenues and cash available for distribution could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options to and from some of our wells and gathering and processing facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within our control. If any of these third party pipelines and other facilities become partially or fully unavailable to transport natural gas, oil or NGLs, or if the gas quality specifications for the natural gas gathering or transportation pipelines or facilities change so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

For example, in Florida, there are a limited number of alternative methods of transportation for our production, and substantially all of our oil production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services for a reasonable fee could result in us having to find transportation alternatives, increased transportation costs, or involuntary curtailment of our oil production in Florida, which could have a negative impact on our future consolidated financial position, results of operations or cash flows.
We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration, production, gathering and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For example, in California, there have been proposals at the legislative and executive levels in the past for tax increases which have included a severance tax as high as 12.5% on all oil production in California, and currently, there is a legislative proposal to impose a 9.5% severance tax on oil. Although the proposals have not passed the California Legislature, the State of California could impose a severance tax on oil in the future. We have significant oil production in California and while we cannot predict the impact of such a tax without having more specifics, the imposition of such a tax could have severe negative impacts on both our willingness and ability to incur capital expenditures in California to increase production, could severely reduce or completely eliminate our California profit margins and would result in lower oil production in our California properties due to the need to shut-in wells and facilities made uneconomic either immediately or at an earlier time than would have previously been the case. There also is currently proposed federal legislation in three areas (tax legislation, climate change and hydraulic fracturing) that if adopted could significantly affect our operations. The following are brief descriptions of the proposed laws:

- **Tax Legislation.** 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 gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and 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) the extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these proposals will be introduced into law and, if so, how soon any resulting 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 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 Common Units.

- **Climate Change Legislation and Regulation.** In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” present an endanergerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

California has been one of the leading states in adopting greenhouse gas emission reduction requirements, and California’s cap and trade program’s first compliance period began in 2012. California's cap and trade program...
requires us to report our greenhouse gas emissions and essentially sets maximum limits or caps on total emissions of greenhouse gases from all industrial sectors that are or become subject to the cap and trade program due to the levels of greenhouse gases that are emitted. This includes the oil and natural gas extraction sector of which we are a part. Our main sources of greenhouse gas emissions for our Southern California oil and gas operations are primarily attributable to emissions from internal combustion engines powering generators to produce electricity, flares for the disposal of excess field gas, and fugitive emission from equipment such as tanks and components. Under the California program, the cap will decline annually from 2013 through 2020. We will be required to obtain compliance instruments for each metric ton of greenhouse gases that we emit, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. A portion of the allowance will be granted by the state, but any shortfall between the state-granted allowance and the facility's emissions will have to be addressed through the purchase of additional allowances either from the state or a third party. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. Although we do not expect the cost to be material to our operations, we cannot predict the future costs of allowances, and such costs could become material to our operations and impose significant costs on our business.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

*Hydraulic Fracturing.* Hydraulic fracturing involves the injection of water, sand, and chemicals under pressure into dense subsurface rock formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel, and in April 2012, the EPA adopted regulations requiring the reduction of volatile organic compound emissions from oil and natural gas production facilities by mandating the use of “green completions” for hydraulic fracturing activities, which requires the operator to recover rather than vent gas and NGLs that return to the surface during well completion operations. At the state level, several states, including California, Texas and Wyoming, have adopted and/or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on water resources. The EPA’s study includes 18 separate research projects addressing topics such as water acquisition, chemical mixing, well injection, flowback and produced water and wastewater treatment and disposal. EPA has indicated that it expects to issue its study report in late 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their findings, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.
A change in the jurisdictional characterization of our gathering assets by federal, state or local regulatory agencies or a change in policy by those agencies with respect to those assets may result in increased regulation of those assets.

Failure to comply with federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and production of, oil and natural gas could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to you. Please read Part I—Item 1 “—Business—Environmental Matters and Regulation” and “—Business—Other Regulation of the Oil and Gas Industry” for a description of the laws and regulations that affect us.

**Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.**

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

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

**Risks Related to Our Structure**

**We may issue additional Common Units without your approval, which would dilute your existing ownership interests.**

We may issue an unlimited number of limited partner interests of any type, including Common Units, without the approval of our unitholders, including in connection with potential acquisitions of oil and gas properties or the reduction of debt, which would dilute your existing ownership interests. For example, in February 2012, we issued 9.2 million Common Units (or approximately 15% of our outstanding Common Units at issuance). In September 2012, we issued 11.5 million Common Units (or approximately 17% of our outstanding Common Units at issuance). In December 2012 we issued 3.0 million Common Units (or approximately 4% of our outstanding Common Units at issuance) in connection with the acquisition of oil and natural gas properties. In February 2013, we issued 14.95 million Common Units (or approximately 18% of our outstanding Common Units at issuance). In November 2013, we issued approximately 18.98 million Common Units (or approximately 16% of our outstanding Common Units at issuance).

The issuance of additional Common Units or other equity securities may have the following effects:

- your proportionate ownership interest in us may decrease;
- the amount of cash distributed on each Common Unit may decrease;
- the relative voting strength of each previously outstanding Common Unit may be diminished;
- the market price of the Common Units may decline; and
- the ratio of taxable income to distributions may increase.

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

41
Our partnership agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- provides that our General Partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decisions were in the best interests of the Partnership;
- generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the Board and not involving a vote of unitholders will not constitute a breach of our partnership agreement or of any fiduciary duty if they are on terms no less favorable to us than those generally provided to or available from unrelated third parties or are “fair and reasonable” to us and that, in determining whether a transaction or resolution is “fair and reasonable,” our General Partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;
- provides that in resolving conflicts of interest where approval of the conflicts committee of the Board is not sought, it will be presumed that in making its decision the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us challenging such approval, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

Unitholders are bound by the provisions of our partnership agreement, including the provisions described above.

Certain of the directors and officers of our General Partner, including the Vice Chairman of the Board, our Chief Executive Officer, our President and other members of our senior management, own interests in PCEC, which is managed by our subsidiary, BreitBurn Management. Conflicts of interest may arise between PCEC, on the one hand, and us and our unitholders, on the other hand. Our partnership agreement limits the remedies available to you in the event you have a claim relating to conflicts of interest.

 Certain of the directors and officers of our General Partner, including the Vice Chairman of the Board, our Chief Executive Officer, our President and other members of our senior management, own interests in PCEC, which is managed by our subsidiary, BreitBurn Management. Conflicts of interest may arise between PCEC, on the one hand, and us and our unitholders, on the other hand. Our partnership agreement limits the remedies available to you in the event you have a claim relating to conflicts of interest.

- Our General Partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, repayments of indebtedness, issuances of additional partnership securities, cash reserves and expenses. Although we have entered into an Omnibus Agreement with PCEC, which addresses the rights of the parties relating to potential business opportunities, conflicts of interest may still arise with respect to the pursuit of such business opportunities. We have agreed in the Omnibus Agreement that PCEC and its affiliates will have a preferential right to acquire any third party upstream oil and natural gas properties that are estimated to contain less than 70% proved developed reserves.
- Currently and historically some officers of our General Partner and many employees of BreitBurn Management have also devoted time to the management of PCEC. This arrangement will continue under the Third Amended and Restated Administrative Services Agreement and this will continue to result in material competition for the time and effort of the officers of our General Partner and employees of BreitBurn Management who provide services to PCEC and who are officers and directors of the sole member of the general partner of PCEC. If the officers of our General Partner and the employees of BreitBurn Management do not devote sufficient attention to the management and operation of our business, our financial results could suffer and our ability to make distributions to our unitholders could be reduced.
See “BreitBurn Management” in Part II—Item 7 “—Management’s Discussion and Analysis of Financial Condition and Results of Operations” in this report for a discussion of Pacific Coast Oil Trust.

Our partnership agreement limits the liability and reduces the fiduciary duties of our General Partner and its directors and officers, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing Common Units, unitholders will be deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.

**Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our Common Units.**

Our partnership agreement restricts unitholders’ voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board, cannot vote on any matter. In addition, solely with respect to the election of directors, our partnership agreement provides that (x) our General Partner and the Partnership will not be entitled to vote their units, if any, and (y) if at any time any person or group beneficially owns 20% or more of any of the outstanding Partnership securities of any class then outstanding and otherwise entitled to vote, then all Partnership securities owned by such person or group in excess of 20% of the outstanding Partnership securities of the applicable class may not be voted, and in each case, the foregoing units will not be counted when calculating the required votes for such matter and will not be deemed to be outstanding for purposes of determining a quorum for such meeting. Such Common Units will not be treated as a separate class of Partnership securities for purposes of our partnership agreement. Notwithstanding the foregoing, the Board may, by action specifically referencing votes for the election of directors, determine that the limitation set forth in clause (y) above will not apply to a specific person or group. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting unitholders’ ability to influence the manner or direction of management.

**Our partnership agreement has provisions that discourage takeovers.**

Certain provisions of our partnership agreement may have the effect of delaying or preventing a change in control. Our directors are elected to staggered terms. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove our General Partner. The provisions contained in our partnership agreement, alone or in combination with each other, may discourage transactions involving actual or potential changes of control.

**Unitholders who are not “Eligible Holders” will not be entitled to receive distributions on or allocations of income or loss on their Common Units, and their Common Units will be subject to redemption.**

In order to comply with U.S. laws with respect to the ownership of interests in oil and gas leases on federal lands, we have adopted certain requirements regarding those investors who may own our Common Units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and gas leases on federal lands. As of the date hereof, Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof and only for so long as the alien is not from a country that the United States federal government regards as denying similar privileges to citizens or corporations of the United States. Unitholders who are not persons or entities who meet the requirements to be an Eligible Holder will not be entitled to receive distributions or allocations of income and loss on their units and they run the risk of having their units redeemed by us at the lower of their purchase price cost or the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our General Partner.

43
We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions to you.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations.

Unitholders may not have limited liability if a court finds that unitholder action constitutes participation in control of our business.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

- we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- your right to act with other unitholders to elect the directors of our General Partner, to remove or replace our General Partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted participation in “control” of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”), we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of Common Units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the Partnership that are known to such purchaser of units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (“IRS”) were to treat us as a corporation for federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our Common Units depends largely on us being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a “qualifying income” requirement. Based on our current operations we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

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

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such tax on us by any such state would reduce the cash available for distribution to our unitholders.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our Common Units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. One such legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our Common Units. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes.

If the IRS contests the federal income tax positions we take, the market for our Common Units may be adversely impacted, and the cost of any IRS contest will reduce our cash available for distribution.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our Common Units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because you will be treated as a partner to whom we will allocate a share of our taxable income which could be different than the cash we distribute, you may be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, even if you receive no cash distribution from us. You may not receive a cash distribution from us equal to your share of our taxable income or even equal to the actual tax liability resulting from that income.

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

If you sell your Common Units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those Common Units. Because distributions to you in excess of your allocable share of our net taxable income decrease your tax basis in your Common Units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you due to potential recapture items,
including depreciation recapture. In addition, because the amount realized will include your share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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

Investment in Common Units by tax-exempt entities, including individual retirement accounts ("IRAs"), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Our partnership agreement generally prohibits non-U.S. persons from owning our units. However, if non-U.S. persons own our units, distributions to such non-U.S. persons will be subject to withholding taxes imposed at the highest tax rate applicable to such non-U.S. person, and each non-U.S. person will be required to file U.S. federal income tax returns and pay tax on its share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our Common Units.

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

Due to a number of factors, including our inability to match transferors and transferees of Common Units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to our unitholders' tax returns.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our Common Units each month based upon the ownership of our Common Units on the first day of each month, instead of on the basis of the date a particular Common Unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to our unitholders' tax returns.

**A unitholder whose units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.**

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.
The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

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

For example, in 2011 as a result of Quicksilver selling approximately 15.7 million of our Common Units together with normal trading activity by other unitholders, greater than 50% of our Common Units traded within a twelve month period and caused a technical termination of the Partnership for federal income tax purposes. This technical termination required the closing of our taxable year for all unitholders on November 30, 2011 and brought about two taxable periods for 2011: January 1, 2011, to November 30, 2011 and December 1, 2011, to December 31, 2011. We were required to file two federal tax returns for the two short periods during the 2011 tax year.

You may be subject to state and local taxes and return filing requirements in jurisdictions where you do not live as a result of investing in our common units.

In addition to federal income taxes, you may be subject to return filing requirements and other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. Further, you may be subject to penalties for failure to comply with those return filing requirements. We currently conduct business and own assets in California, Colorado, Florida, Indiana, Kentucky, Michigan, Texas, Utah and Wyoming. Each of these states other than Florida, Texas and Wyoming currently imposes a personal income tax on individuals, and all of these states impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may conduct business or own assets in additional states that impose a personal income tax. It is the responsibility of each unitholder to file all U.S. federal, state and local tax returns.
Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

The information required to be disclosed in this Item 2 is incorporated herein by reference to Part I—Item 1 “—Business.”

Item 3. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material pending legal proceedings or know of any such procedures contemplated by government authorities. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Item 4. Mine Safety Disclosures.

Not applicable.
PART II

Item 5. Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.

Our Common Units trade on the NASDAQ Global Select Market under the symbol “BBEP.” As of December 31, 2013, based upon information received from our transfer agent and brokers and nominees, we had approximately 87,239 common unitholders of record.

The following table sets forth high and low sales prices per Common Unit for the periods indicated. The last reported sales price for our Common Units on February 27, 2014 was $19.87 per unit.

<table>
<thead>
<tr>
<th></th>
<th>Price Range</th>
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<tbody>
<tr>
<td></td>
<td>High</td>
</tr>
<tr>
<td><strong>2013</strong></td>
<td></td>
</tr>
<tr>
<td>Fourth Quarter</td>
<td>$20.41</td>
</tr>
<tr>
<td>Third Quarter</td>
<td>$18.71</td>
</tr>
<tr>
<td>Second Quarter</td>
<td>$20.76</td>
</tr>
<tr>
<td>First Quarter</td>
<td>$21.75</td>
</tr>
<tr>
<td><strong>2012</strong></td>
<td></td>
</tr>
<tr>
<td>Fourth Quarter</td>
<td>$20.47</td>
</tr>
<tr>
<td>Third Quarter</td>
<td>$19.85</td>
</tr>
<tr>
<td>Second Quarter</td>
<td>$19.20</td>
</tr>
<tr>
<td>First Quarter</td>
<td>$20.19</td>
</tr>
</tbody>
</table>

Distributions

We intend to make cash distributions of available cash to unitholders on a monthly basis, although there is no assurance as to future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our credit agreement restricts us from making cash distributions unless, after giving effect to such distribution, we remain in compliance with all terms and conditions of our credit facility. See Item 7 “—Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facility” and Note 10 to the consolidated financial statements in this report.

On October 30, 2013, the Partnership changed its distribution payment policy from a quarterly payment schedule to a monthly payment schedule beginning with the distributions relating to the fourth quarter of 2013. For the quarters for which we declare a distribution, we expect that the distribution for the quarter will be made in three equal monthly payments within 17, 45 and 75 days following the end of each quarter to unitholders of record on the applicable record date. Prior to the distribution policy change, for the quarters for which we declared a distribution, distributions of available cash were made within 45 days after the end of the quarter to unitholders of record on the applicable record date.

Available cash, as defined in our partnership agreement, generally is all cash on hand, including cash from borrowings, at the end of the quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs.

49
The following table provides a summary of distributions paid for the years ended December 31, 2013 and 2012:

<table>
<thead>
<tr>
<th></th>
<th>Total</th>
<th>Per Common Unit</th>
<th>Payment Date</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2014 (a)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>February 2014</td>
<td>$20,037</td>
<td>$0.1642</td>
<td>2/14/2014</td>
</tr>
<tr>
<td>January 2014</td>
<td>$19,573</td>
<td>$0.1642</td>
<td>1/16/2014</td>
</tr>
<tr>
<td><strong>2013</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Third Quarter</td>
<td>$48,594</td>
<td>$0.4875</td>
<td>11/14/2013</td>
</tr>
<tr>
<td>Second Quarter</td>
<td>$47,846</td>
<td>$0.4800</td>
<td>8/14/2013</td>
</tr>
<tr>
<td>First Quarter</td>
<td>$47,348</td>
<td>$0.4750</td>
<td>5/14/2013</td>
</tr>
<tr>
<td><strong>2012</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fourth Quarter</td>
<td>$39,823</td>
<td>$0.4700</td>
<td>2/14/2013</td>
</tr>
<tr>
<td>Third Quarter</td>
<td>$37,499</td>
<td>$0.4650</td>
<td>11/14/2012</td>
</tr>
<tr>
<td>Second Quarter</td>
<td>$31,806</td>
<td>$0.4600</td>
<td>8/14/2012</td>
</tr>
<tr>
<td>First Quarter</td>
<td>$31,461</td>
<td>$0.4550</td>
<td>5/14/2012</td>
</tr>
</tbody>
</table>

(a) Reflects the change in our distribution policy where distributions attributable to the fourth quarter of 2013 were paid out in equal monthly payments in January and February. The March distribution was declared on February 27, 2014 and will be payable on March 14, 2014.

**Equity Compensation Plan Information**

See Part III—Item 12 “—Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters” for information regarding securities authorized for issuance under equity compensation plans.

**Unregistered Sales of Equity Securities and Use of Proceeds**

There were no sales of unregistered equity securities during the period covered by this report.

**Purchases of Equity Securities by the Issuer and Affiliated Purchasers**

There were no purchases of our Common Units by us or any affiliated purchasers during the fourth quarter of 2013.
Common Unit Performance Graph

The graph below compares our cumulative total unitholder return on our Common Units over the past five years with the cumulative total returns over the same period of the Russell 2000 index and the Alerian MLP index. The graph assumes that the value of the investment in our Common Units, in the Russell 2000 index and in the Alerian MLP index was $100 on December 31, 2008. Cumulative return is computed assuming reinvestment of dividends.

Comparison of Cumulative Total Return among the Partnership, the Russell 2000 Index and the Alerian MLP Index

The information in this report appearing under the heading “Common Unit Performance Graph” is being furnished pursuant to Item 2.01(e) of Regulation S-K and shall not be deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

We have derived the selected financial data set forth in the following table for each of the years ended December 31, 2013, 2012 and 2011, with the exception of consolidated balance sheet data for the year ended December 31, 2011, from our audited consolidated financial statements appearing elsewhere in this report. We derived the financial data for the years ended December 31, 2010 and 2009, as well as consolidated balance sheet data for the year ended December 31, 2011, from our prior year audited consolidated financial statements, which are not included in this report.

On July 15, 2013, we completed the Whiting Acquisition for approximately $845 million. We also completed the acquisition of additional interests in the Oklahoma Panhandle for an additional $30 million on July 15, 2013. On December 30, 2013, we completed the 2013 Permian Basin Acquisitions from CrownRock, L.P. for approximately $282 million. We also completed the acquisition of additional interests in certain of the acquired assets in the Permian Basin from other sellers for an additional $20 million in December 2013. In 2012, we completed the NiMin Acquisition on June 28, 2012 for approximately $95 million. On July 2, 2012, we completed acquisitions of oil and natural gas properties located in the Permian Basin in Texas from Element Petroleum, LP and CrownRock, L.P. for approximately $148 million and $70 million, respectively. On November 30, 2012, we completed the AEO Acquisition on for approximately $38 million in cash and approximately 3.01 million Common Units. On December 28, 2012, we completed the acquisition of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P., Lynden USA Inc. and Piedra Energy I, LLC for approximately $164 million, $25 million and $10 million, respectively. Effective April 1, 2012, our ownership interest in properties at two California fields decreased from approximately 95% to approximately 62%. See Note 16 to the consolidated financial statements in this report. In 2011, we completed the Greasewood Acquisition on July 28, 2011 for approximately $57 million and the Cabot Acquisition on October 6, 2011 for approximately $281 million. See Note 4 to the consolidated financial statements in this report for further details about our acquisitions in 2013, 2012 and 2011.

You should read the following selected financial data in conjunction with Part II—Item 7 “—Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and related notes in this report.
### Statement of Operations Data:

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</thead>
<tbody>
<tr>
<td>Oil, natural gas and NGLs sale</td>
<td>$660,665</td>
<td>$413,867</td>
<td>$394,393</td>
<td>$317,738</td>
<td>$254,917</td>
</tr>
<tr>
<td>Gain (loss) on commodity derivative instruments, net</td>
<td>$(29,182)</td>
<td>5,580</td>
<td>81,667</td>
<td>35,112</td>
<td>(51,437)</td>
</tr>
<tr>
<td>Other revenue, net</td>
<td>3,175</td>
<td>3,548</td>
<td>4,310</td>
<td>2,498</td>
<td>1,382</td>
</tr>
<tr>
<td><strong>Total revenue</strong></td>
<td>$634,658</td>
<td>$422,995</td>
<td>$480,370</td>
<td>$355,348</td>
<td>$204,862</td>
</tr>
</tbody>
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</thead>
<tbody>
<tr>
<td><strong>Operating income (loss)</strong></td>
<td>44,276</td>
<td>21,700</td>
<td>153,809</td>
<td>63,743</td>
<td>(82,811)</td>
</tr>
<tr>
<td><strong>Net income (loss)</strong></td>
<td>(43,671)</td>
<td>(40,739)</td>
<td>110,698</td>
<td>34,913</td>
<td>(107,257)</td>
</tr>
<tr>
<td>Less: Net income attributable to noncontrolling interest</td>
<td>—</td>
<td>(62)</td>
<td>(201)</td>
<td>(162)</td>
<td>(33)</td>
</tr>
<tr>
<td><strong>Net income (loss) attributable to the partnership</strong></td>
<td>$43,671</td>
<td>$(40,801)</td>
<td>$110,497</td>
<td>$34,751</td>
<td>$(107,290)</td>
</tr>
<tr>
<td>Basic net income (loss) per unit</td>
<td>$(0.43)</td>
<td>$(0.56)</td>
<td>$1.80</td>
<td>$0.61</td>
<td>$(2.03)</td>
</tr>
<tr>
<td>Diluted net income (loss) per unit</td>
<td>$(0.43)</td>
<td>$(0.56)</td>
<td>$1.79</td>
<td>$0.61</td>
<td>$(2.03)</td>
</tr>
</tbody>
</table>

### Cash Flow Data:

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</tr>
</thead>
<tbody>
<tr>
<td>Net cash provided by operating activities</td>
<td>$257,166</td>
<td>$191,782</td>
<td>$128,543</td>
<td>$182,022</td>
<td>$224,358</td>
</tr>
<tr>
<td>Net cash used in investing activities</td>
<td>$(1,465,805)</td>
<td>$(697,159)</td>
<td>$(414,573)</td>
<td>$(68,286)</td>
<td>$(6,229)</td>
</tr>
<tr>
<td>Net cash provided by (used in) financing activities</td>
<td>$1,206,590</td>
<td>$504,556</td>
<td>$287,728</td>
<td>$(115,872)</td>
<td>$(214,909)</td>
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### Balance Sheet Data (at period end):

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<tbody>
<tr>
<td>Cash</td>
<td>$2,458</td>
<td>$4,507</td>
<td>$5,328</td>
<td>$3,630</td>
<td>$5,766</td>
</tr>
<tr>
<td>Other current assets</td>
<td>114,604</td>
<td>109,158</td>
<td>167,492</td>
<td>121,674</td>
<td>136,675</td>
</tr>
<tr>
<td>Net property, plant and equipment</td>
<td>3,915,376</td>
<td>2,711,893</td>
<td>2,072,759</td>
<td>1,722,295</td>
<td>1,741,089</td>
</tr>
<tr>
<td>Other assets</td>
<td>163,844</td>
<td>89,936</td>
<td>85,270</td>
<td>82,568</td>
<td>87,499</td>
</tr>
<tr>
<td><strong>Total assets</strong></td>
<td>$4,196,282</td>
<td>$2,915,494</td>
<td>$2,330,849</td>
<td>$1,930,167</td>
<td>$1,971,029</td>
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</thead>
<tbody>
<tr>
<td>Current liabilities</td>
<td>$182,889</td>
<td>$115,240</td>
<td>$89,889</td>
<td>$101,317</td>
<td>$91,890</td>
</tr>
<tr>
<td>Long-term debt</td>
<td>1,889,675</td>
<td>1,100,696</td>
<td>820,613</td>
<td>528,116</td>
<td>559,000</td>
</tr>
<tr>
<td>Other long-term liabilities</td>
<td>133,898</td>
<td>110,022</td>
<td>93,133</td>
<td>91,477</td>
<td>91,338</td>
</tr>
<tr>
<td>Partners’ equity</td>
<td>1,989,820</td>
<td>1,589,536</td>
<td>1,326,764</td>
<td>1,208,803</td>
<td>1,228,373</td>
</tr>
<tr>
<td>Noncontrolling interest</td>
<td>—</td>
<td>—</td>
<td>450</td>
<td>454</td>
<td>428</td>
</tr>
<tr>
<td><strong>Total liabilities and partners’ equity</strong></td>
<td>$4,196,282</td>
<td>$2,915,494</td>
<td>$2,330,849</td>
<td>$1,930,167</td>
<td>$1,971,029</td>
</tr>
</tbody>
</table>

### Cash dividends declared per unit outstanding:

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<tbody>
<tr>
<td>$1.9125</td>
<td>$1.8300</td>
<td>$1.6875</td>
<td>$1.1475</td>
<td>$0.5200</td>
<td></td>
</tr>
</tbody>
</table>
The following table presents a non-GAAP financial measure, “Adjusted EBITDA,” which we use in our business. This measure is not calculated or presented in accordance with US GAAP.

We believe the presentation of Adjusted EBITDA provides useful information to investors to evaluate the operations of our business excluding certain items and for the reasons set forth below. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with US GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

We use Adjusted EBITDA to assess:

• the financial performance of our assets, without regard to financing methods, capital structure or historical cost basis;
• our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure;
• the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities; and
• the ability of our assets to generate cash sufficient to pay interest costs, pay distributions and support our indebtedness.

The following table presents a reconciliation of Adjusted EBITDA to net income (loss) attributable to the partnership and cash flows provided by operating activities, our most directly comparable US GAAP financial performance measures, for each of the periods indicated.
Reconciliation of consolidated net income (loss) to Adjusted EBITDA:

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<tbody>
<tr>
<td>Net income (loss) attributable to the partnership</td>
<td>(43,671)</td>
<td>(40,801)</td>
<td>110,497</td>
<td>34,751</td>
<td>(107,290)</td>
</tr>
<tr>
<td>(Gain) loss on commodity derivative instruments (a)</td>
<td>29,182</td>
<td>(5,580)</td>
<td>(81,667)</td>
<td>(35,112)</td>
<td>51,437</td>
</tr>
<tr>
<td>Commodity derivative instrument settlements (b)(c)(d)</td>
<td>8,083</td>
<td>87,605</td>
<td>(16,067)</td>
<td>74,825</td>
<td>167,683</td>
</tr>
<tr>
<td>Depletion, depreciation and amortization</td>
<td>216,495</td>
<td>137,252</td>
<td>106,855</td>
<td>96,472</td>
<td>106,843</td>
</tr>
<tr>
<td>Impairments</td>
<td>54,373</td>
<td>12,313</td>
<td>648</td>
<td>6,286</td>
<td>—</td>
</tr>
<tr>
<td>Interest expense and other financing costs</td>
<td>87,067</td>
<td>61,206</td>
<td>39,165</td>
<td>24,552</td>
<td>18,827</td>
</tr>
<tr>
<td>Loss on interest rate swaps (e)</td>
<td>—</td>
<td>1,101</td>
<td>2,777</td>
<td>4,490</td>
<td>7,246</td>
</tr>
<tr>
<td>Settlement payments (receipts) on terminated derivatives</td>
<td>—</td>
<td>—</td>
<td>36,779</td>
<td>—</td>
<td>(70,587)</td>
</tr>
<tr>
<td>(Gain) loss on sale of assets</td>
<td>(2,015)</td>
<td>486</td>
<td>(111)</td>
<td>14</td>
<td>5,965</td>
</tr>
<tr>
<td>Income tax expense (benefit)</td>
<td>905</td>
<td>84</td>
<td>1,188</td>
<td>(204)</td>
<td>(1,528)</td>
</tr>
<tr>
<td>Amortization of intangibles</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>495</td>
<td>2,771</td>
</tr>
<tr>
<td>Unit based compensation</td>
<td>19,955</td>
<td>22,184</td>
<td>22,002</td>
<td>20,331</td>
<td>13,619</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong></td>
<td><strong>370,374</strong></td>
<td><strong>275,850</strong></td>
<td><strong>222,066</strong></td>
<td><strong>226,900</strong></td>
<td><strong>194,986</strong></td>
</tr>
</tbody>
</table>

(a) The Partnership enters into certain derivative instrument contracts such as put options that require the payment of premiums at contract inception. Gain (loss) on commodity derivative instruments includes the reduction of premium value for derivative instruments over time. The Partnership’s calculation of adjusted EBITDA does not include premiums paid for derivative instruments at contract inception as these payments pertain to future contract settlement periods.

(b) Includes net cash settlements on derivative instruments:

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<tbody>
<tr>
<td>- Oil settlements received (paid) of:</td>
<td>(36,183)</td>
<td>3,855</td>
<td>(70,398)</td>
<td>11,252</td>
<td>66,176</td>
</tr>
<tr>
<td>- Natural gas settlements received of:</td>
<td>44,266</td>
<td>83,750</td>
<td>54,331</td>
<td>63,573</td>
<td>101,507</td>
</tr>
</tbody>
</table>

(c) Includes premiums deferred and paid at the time of derivative contract settlements each period of: — — — 1,820 1,116

(d) Excludes premiums paid at contract inception related to those derivative contracts that settled during the periods of: 4,893 859 — — —

(e) Includes settlements paid on interest rate derivatives including terminated interest rate derivatives of: — 5,469 3,257 11,087 13,115
Reconciliation of net cash flows from operating activities to Adjusted EBITDA:

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<tbody>
<tr>
<td>Net cash provided by operating activities</td>
<td>$257,166</td>
<td>$191,782</td>
<td>$128,543</td>
<td>$182,022</td>
<td>$224,358</td>
</tr>
<tr>
<td>Increase in assets (net of liabilities) relating to operating activities</td>
<td>32,105</td>
<td>22,492</td>
<td>18,942</td>
<td>15,131</td>
<td>12,466</td>
</tr>
<tr>
<td>Interest expense</td>
<td>80,617</td>
<td>61,807</td>
<td>37,702</td>
<td>30,161</td>
<td>28,647</td>
</tr>
<tr>
<td>(Gain) loss on early termination of commodity derivatives</td>
<td>—</td>
<td>—</td>
<td>36,779</td>
<td>—</td>
<td>(70,587)</td>
</tr>
<tr>
<td>Income from equity affiliates, net</td>
<td>(55)</td>
<td>(487)</td>
<td>(210)</td>
<td>(450)</td>
<td>(1,302)</td>
</tr>
<tr>
<td>Incentive compensation expense</td>
<td>(21)</td>
<td>(82)</td>
<td>(41)</td>
<td>(93)</td>
<td>958</td>
</tr>
<tr>
<td>Incentive compensation paid</td>
<td>—</td>
<td>—</td>
<td>78</td>
<td>91</td>
<td>217</td>
</tr>
<tr>
<td>Income taxes</td>
<td>562</td>
<td>400</td>
<td>474</td>
<td>199</td>
<td>262</td>
</tr>
<tr>
<td>Non-controlling interest</td>
<td>—</td>
<td>(62)</td>
<td>(201)</td>
<td>(162)</td>
<td>(33)</td>
</tr>
<tr>
<td>Adjusted EBITDA</td>
<td>$370,374</td>
<td>$275,850</td>
<td>$222,066</td>
<td>$226,900</td>
<td>$194,986</td>
</tr>
</tbody>
</table>
Executive Overview

We are an independent oil and gas partnership focused on the acquisition, exploitation and development of oil and gas properties in the United States. Our objective is to manage our oil and gas producing properties for the purpose of generating cash flow and making distributions to our unitholders. Our assets consist primarily of producing and non-producing oil, NGL and natural gas reserves located primarily in the Antrim Shale and other non-Antrim formations in Michigan, the Oklahoma Panhandle, the Permian Basin in Texas, the Evanston, Green River, Wind River, Big Horn and Powder River Basins in Wyoming, the Los Angeles and San Joaquin Basins in California, the Sunniland Trend in Florida and the New Albany Shale in Indiana and Kentucky.

Our core investment strategy includes the following principles:

- acquire long-lived assets with low-risk exploitation and development opportunities;
- use our technical expertise and state-of-the-art technologies to identify and implement successful exploitation techniques to optimize reserve recovery;
- reduce cash flow volatility through commodity price and interest rate derivatives; and
- maximize asset value and cash flow stability through operating and technical expertise.

2013 Acquisitions

On July 15, 2013, we completed the Whiting Acquisition for approximately $845 million in cash, and we also acquired additional interests in certain of the acquired assets in the Oklahoma Panhandle from other sellers for an additional $30 million. The Whiting Acquisition included the Postle Field, which is currently an active CO₂ enhanced recovery project, and the Northeast Hardesty Unit, both of which are located in Texas County, Oklahoma. We have a contracted supply of CO₂ in the Bravo Dome Field in New Mexico with step-in rights, for 143 Bcf over the next 10 to 15 years, which we expect will provide the volumes required to produce our estimated proved reserves when coupled with recycled CO₂. As part of the acquisition and the purchase of additional interests, we also became the sole owner of the Dry Trails gas plant located in Texas County, Oklahoma and the 120-mile Transpetco Pipeline, a CO₂ transportation pipeline delivering product from New Mexico to the Postle Field in Oklahoma. We funded the purchase price for the Whiting Acquisition and the acquisition of additional interests in certain of the acquired assets in the Oklahoma Panhandle with borrowings under our credit facility.

On December 30, 2013, we completed the acquisitions of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P. for approximately $282 million and additional interests in certain of the acquired assets in the Permian Basin from other sellers for an additional $20 million.

2013 Highlights

In 2013, we declared cash distributions to unitholders totaling $183.6 million. Starting with the fourth quarter of 2013, we changed our distribution policy from paying quarterly distributions to paying monthly distributions for the quarters for which we declare a distribution. On January 16, 2014, we paid a cash distribution to unitholders totaling $19.6 million, or $0.1642 per Common Unit, for the first monthly distribution attributable to the fourth quarter of 2013. On February 14, 2014, we paid a cash distribution to unitholders of $20.0 million, or $0.1642 per Common Unit, for the second monthly distribution attributable to the fourth quarter of 2013. On February 27, 2014, we declared a cash
distribution to unitholders of $0.1642 per Common Unit for the third monthly payment attributable to the fourth quarter of 2013. We increased our quarterly cash distributions from $0.4700 per Common Unit for the fourth quarter of 2012 to $0.4925 per Common Unit for the fourth quarter of 2013.

In 2013, our capital expenditures, including capitalized engineering costs and excluding acquisitions, totaled approximately $295 million, compared with approximately $153 million in 2012. We spent approximately $104.3 million in Texas, $81.1 million in California, $43.9 million in Oklahoma, $29.5 million in Florida, $26.4 million in Wyoming and $9.4 million in Michigan and Kentucky. We drilled and completed four new wells and 15 recompletions in Michigan. We drilled and completed four new productive wells in Oklahoma, 53 new productive wells in Texas and three productive wells in Florida. We drilled 23 new wells and completed 21 productive wells, recompleted 19 wells and two workovers in Wyoming. We drilled and completed 34 new productive wells, six recompletions and 12 workovers in California. Primarily as a result of our 2013 acquisitions and our capital spending, our 2013 production was 10,983 MBoe, which was 32% higher than our 2012 production.

In February 2013, we sold approximately 14.95 million Common Units to the public at a price of $19.86 per Common Unit, resulting in proceeds of $285.0 million (net of underwriting discounts and offering expenses), which we used to repay outstanding debt under our credit facility.

In November 2013, we sold approximately 18.98 million Common Units to the public at a price of $18.22 per Common Unit, resulting in proceeds of $333.2 million (net of underwriting discounts and offering expenses), which we primarily used to repay outstanding debt under our credit facility.

In November 2013, we and BreitBurn Finance Corporation, and certain of our subsidiaries as guarantors, issued $400 million in aggregate principal amount of 7.875% Senior Notes due 2022 at a price of 100.250%. We received net proceeds of approximately $393.4 million and used the proceeds to reduce borrowings under our credit facility.

Outlook

In 2014, our oil, NGL and natural gas capital spending program, including capitalized engineering costs and excluding acquisitions, is expected to be between $325 million and $345 million, compared with approximately $295 million in 2013. In 2014, we anticipate spending approximately 92% principally on oil projects in Texas, California, and Oklahoma and approximately 8% principally on oil projects in Florida, Wyoming and Michigan. We anticipate 85% of our total capital spending will be focused on drilling and rate-generating projects that are designed to increase or add to production or reserves. We plan to drill 168 wells with 156 wells expected in Texas and California and 12 wells expected in Wyoming, Michigan and Florida. Without considering potential acquisitions, we expect our 2014 production to be between 13.6 MMBoe and 14.4 MMBoe.

Commodity hedging remains an important part of our strategy to reduce cash flow volatility. We use swaps, collars and options for managing risk relating to commodity prices. As of February 27, 2014, we have hedged approximately 76% of our expected 2014 production. For 2014, we have 20,114 Bbl/d of oil and 55,100 MMBtu/d of natural gas hedged at average prices of approximately $93.70 per Bbl and $4.95 per MMBtu, respectively. For 2015, we have 17,989 Bbl/d of oil and 56,700 MMBtu/d of natural gas hedged at average prices of approximately $93.54 per Bbl and $4.94 per MMBtu, respectively. For 2016, we have 15,011 Bbl/d of oil and 41,700 MMBtu/d of natural gas hedged at average prices of approximately $89.48 per Bbl and $4.32 per MMBtu, respectively. For 2017, we have 8,269 Bbl/d of oil and 18,571 MMBtu/d of natural gas hedged at average prices of approximately $84.71 per Bbl and $4.44 per MMBtu, respectively. For 2018, we have 493 Bbl/d of oil and 1,870 MMBtu/d hedged at average prices of approximately $82.20 per Bbl and $4.15 per MMBtu, respectively.

Operational Focus

We use a variety of financial and operational measures to assess our performance. Among these measures are the following: volumes of oil and natural gas produced, amount of reserves replaced, realized prices, operating expenses and G&A.
As of December 31, 2013, our total estimated proved reserves were 214.3 MMBoe, of which approximately 53% was oil, 7% was NGLs and 40% was natural gas. As of December 31, 2012, our total estimated proved reserves were 149.4 MMBoe, of which approximately 49% was oil, 4% was NGLs, and 47% was natural gas. Net changes to our total estimated proved reserve included additions from 2013 acquisitions of 60.9 MMBoe and positive reserve revisions of 13.7 MMBoe and 1.3 MMBoe in extensions and discoveries offset by 11.0 MMBoe of production, resulting in a net increase of 64.9 MMBoe from 2012. The reserve revisions in 2013 were primarily the result of a 86.0 Bcf increase in natural gas reserves driven primarily by an increase in commodity prices and additional drilling, recompletions and workovers. The unweighted average first-day-of-the-month oil and natural gas prices used to determine our total estimated proved reserves as of December 31, 2013 were $96.94 per Bbl of oil for WTI spot price and $108.32 per Bbl of oil for ICE Brent and $3.67 per MMBtu of natural gas for Henry Hub spot price, compared to $94.71 per Bbl of oil for WTI spot price, $111.77 per Bbl of oil for ICE Brent and $2.76 per MMBtu of natural gas for Henry Hub spot price in 2012. The unweighted average first-day-of-the-month oil and natural gas prices used to determine our total estimated proved reserves as of December 31, 2011 were $95.97 per Bbl of oil for WTI spot price, $112.47 per Bbl of oil for ICE Brent and $4.12 per MMBtu of oil for Henry Hub spot price.

Of our total estimated proved reserves as of December 31, 2013, 27% were located in Michigan, 20% in Oklahoma, 19% in Texas, 17% in Wyoming, 11% in California, 5% in Florida and than 1% located in Indiana and Kentucky.

Our revenues and net income are sensitive to oil, NGL and natural gas prices. Our operating expenses are highly correlated to oil prices, and as oil prices rise and fall, our operating expenses will directionally rise and fall. Significant factors that will impact near-term commodity prices include global demand for oil and natural gas, political developments in oil producing countries including, without limitation, the extent to which members of the OPEC and other oil exporting nations are able to manage oil supply through export quotas, and variations in key North American natural gas and refined products supply and demand indicators.

Although oil, NGL and natural gas prices have historically exhibited significant volatility, the markets remained relatively stable in 2013. Domestic oil prices rose steadily into the summer, followed by a few months of decline towards the end of the year. In 2013, the WTI spot price averaged approximately $98 per Bbl, compared with approximately $94 per Bbl a year earlier. During 2013, the WTI spot price ranged from a low of $87 per Bbl to a high of $111 per Bbl, with the monthly average ranging from a low of $92 per Bbl in April to a high of $107 per Bbl in August. In 2012, prices ranged from a monthly average low of $82 per Bbl in June to a monthly average high of $106 per Bbl in March. In 2014 to date, the WTI spot price has averaged $95 per Bbl. Historically, there has been a strong relationship between changes in NGL and oil prices. NGL prices are correlated to North American supply and petrochemical demands.

Prices for natural gas in many markets are aligned both with supply and demand conditions in their respective regional markets and with the overall U.S. market. Natural gas prices are also typically higher during the winter period when demand for heating is greatest in the U.S. Since January 2010 to present, monthly average natural gas spot prices at Henry Hub have ranged from a low of $1.95 per MMBtu in April 2012 to a high of $5.83 per MMBtu in January 2010. During 2013, the natural gas spot price at Henry Hub ranged from a low of $3.08 per MMBtu to a high of $4.52 per MMBtu, with the monthly average ranging from a low of $3.33 per MMBtu in February to a high of $4.23 per MMBtu in December, and averaged approximately $3.73 per MMBtu for the year. During 2012, the natural gas spot price at Henry Hub ranged from a low of $1.82 per MMBtu to a high of $3.77 per MMBtu, and averaged approximately $2.75 per MMBtu. In 2014 to date, the natural gas spot price at Henry Hub has averaged approximately $3.32 per MMBtu.

Excluding the effect of derivatives, our average realized oil price for 2013 increased $1.49 per Boe to $93.67 per Boe as compared to $92.18 per Boe in 2012. Including the effects of derivative instruments, our realized average oil price increased $0.44 per Boe to $91.26 per Boe as compared to $90.82 per Boe in 2012, primarily due to a higher average oil hedge price. Excluding the effect of derivatives, our realized natural gas price for 2013 increased $0.82 per Mcf to $3.82 per Mcf compared to $3.00 per Mcf in 2012. Including the effects of derivative instruments, our average realized natural gas price for 2013 decreased $0.60 per Mcf to $5.39 per Mcf as compared to $5.99 per Mcf in 2012.

While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow and distributions, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected.
In evaluating our production operations, we frequently monitor and assess our operating and G&A expenses per Boe produced. These measures allow us to better evaluate our operating efficiency and are used in reviewing the economic feasibility of a potential acquisition or development project.

Operating expenses are the costs incurred in the operation of producing properties. Expenses for utilities, direct labor, water injection and disposal, production taxes and materials and supplies comprise the most significant portion of our operating expenses. A majority of our operating cost components are variable and increase or decrease along with our levels of production. For example, we incur power costs in connection with various production related activities such as pumping to recover oil and gas, separation and treatment of water produced in connection with our oil and gas production and re-injection of water produced into the oil producing formation to maintain reservoir pressure. Although these costs typically vary with production volumes, they are driven not only by volumes of oil and gas produced but also volumes of water produced. Consequently, fields that have a high percentage of water production relative to oil and gas production, also known as a high water cut, will experience higher levels of power costs for each Boe produced. Certain items, however, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased expenses in periods during which they are performed. Our operating expenses are highly correlated to oil prices, and we experience upward or downward pressure on material and service costs depending on how oil prices change. These costs include specific expenditures such as lease fuel, electricity, drilling services and severance and property taxes. Lease operating expenses, including processing fees, were $19.69 per Boe in 2013 and $19.15 per Boe in 2012. The increase in per Boe lease operating expenses was primarily due to higher operating costs attributable to our properties in Wyoming, Florida and Texas.

Production taxes vary by state. All states in which we operate impose ad valorem taxes on our oil and gas properties. Various states regulate the drilling for, and the production, gathering and sale of, oil, NGLs and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Currently, Texas, Wyoming, Oklahoma, Michigan, Indiana, Kentucky and Florida impose severance taxes on producers at rates ranging from 1% to 9% of the value of the gross product extracted. Wyoming wells that reside on Native American or federal land are subject to an additional tax of 8.5%. California does not currently impose a severance tax; rather it imposes an ad valorem tax based in large part on the value of the mineral interests in place. See Part I—Item 1A “—Risk Factors” — “Risks Related to Our Business — We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations” in this report.

We recorded asset impairment charges of $54.4 million during 2013. A decline in future commodity prices could result in additional impairment charges. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management’s estimates of future production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward commodity prices alone could result in impairment.

G&A, excluding unit based compensation, was $3.53 per Boe in 2013 and $4.00 per Boe in 2012. The decrease in per Boe G&A, excluding unit based compensation, reflects the additional production from our 2013 acquisitions.

BreitBurn Management

BreitBurn Management operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. All of our employees, including our executives, are employees of BreitBurn Management. BreitBurn Management also operates the assets of PCEC, our Predecessor. In addition to a monthly fee for indirect expenses, BreitBurn Management charges PCEC for all direct expenses including incentive plan costs and direct payroll and administrative costs related to PCEC’s properties and operations.

For information on potential conflicts between us and PCEC, see Part I—Item 1A “—Risk Factors” — “Risks Related to Our Structure — Certain of the directors and officers of our General Partner, including the Vice Chairman of our Board, our Chief Executive Officer, our President and other members of our senior management, own interests in PCEC, which is managed by our subsidiary, BreitBurn Management. Conflicts of interest may arise between PCEC, on
the one hand, and us and our unitholders, on the other hand. Our partnership agreement limits the remedies available to you in the event you have a claim relating to conflicts of interest.”

See Note 5 to the consolidated financial statements in this report for more information regarding our relationship with BreitBurn Management and PCEC.
## Results of Operations

The table below summarizes certain of the results of operations and period-to-period comparisons attributable to our operations for the periods indicated. These results are presented for illustrative purposes only and are not indicative of our future results. The data reflect our results as they are presented in our consolidated financial statements.

<table>
<thead>
<tr>
<th>Thousands of dollars, except as indicated</th>
<th>Year Ended December 31,</th>
<th>Increase / decrease %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total production (MBoe) (a)</td>
<td>10,983</td>
<td>8,318</td>
</tr>
<tr>
<td>Oil (MBbl)</td>
<td>5,651</td>
<td>3,514</td>
</tr>
<tr>
<td>NGLs (MBbl)</td>
<td>640</td>
<td>138</td>
</tr>
<tr>
<td>Natural gas (MMcf)</td>
<td>28,156</td>
<td>27,997</td>
</tr>
<tr>
<td>Average daily production (Boe/d)</td>
<td>30,091</td>
<td>22,726</td>
</tr>
<tr>
<td>Sales volumes (MBoe)</td>
<td>10,988</td>
<td>8,334</td>
</tr>
<tr>
<td>Average realized sales price (per Boe) (b) (c)</td>
<td>$60.05</td>
<td>$49.57</td>
</tr>
<tr>
<td>Oil (per Bbl) (c) (d)</td>
<td>93.67</td>
<td>92.18</td>
</tr>
<tr>
<td>NGLs (per Bbl)</td>
<td>35.25</td>
<td>27.96</td>
</tr>
<tr>
<td>Natural gas (per Mcf)</td>
<td>3.82</td>
<td>3.00</td>
</tr>
<tr>
<td>Oil sales</td>
<td>$530,625</td>
<td>$326,130</td>
</tr>
<tr>
<td>NGL sales</td>
<td>22,558</td>
<td>3,858</td>
</tr>
<tr>
<td>Natural gas sales</td>
<td>107,482</td>
<td>83,879</td>
</tr>
<tr>
<td>Gain (loss) on commodity derivative instruments (e)</td>
<td>(29,182)</td>
<td>5,580</td>
</tr>
<tr>
<td>Other revenues, net</td>
<td>3,175</td>
<td>3,548</td>
</tr>
<tr>
<td>Total revenues</td>
<td>$634,658</td>
<td>$422,995</td>
</tr>
<tr>
<td>Lease operating expenses including processing fees</td>
<td>$216,275</td>
<td>$159,289</td>
</tr>
<tr>
<td>Production and property taxes (f)</td>
<td>46,220</td>
<td>33,634</td>
</tr>
<tr>
<td>Total lease operating expenses</td>
<td>262,495</td>
<td>192,923</td>
</tr>
<tr>
<td>Purchases and other operating costs</td>
<td>1,322</td>
<td>1,577</td>
</tr>
<tr>
<td>Change in inventory</td>
<td>(995)</td>
<td>1,279</td>
</tr>
<tr>
<td>Total operating costs</td>
<td>$262,822</td>
<td>$195,779</td>
</tr>
<tr>
<td>Lease operating expenses pre-taxes per Boe (g)</td>
<td>$19.69</td>
<td>$19.15</td>
</tr>
<tr>
<td>Production and property taxes per Boe</td>
<td>4.21</td>
<td>4.04</td>
</tr>
<tr>
<td>Total lease operating expenses per Boe</td>
<td>$23.90</td>
<td>$23.19</td>
</tr>
<tr>
<td>Depletion, depreciation and amortization</td>
<td>$216,495</td>
<td>$137,252</td>
</tr>
<tr>
<td>Impairments</td>
<td>$54,373</td>
<td>$12,313</td>
</tr>
<tr>
<td>G&amp;A excluding unit based compensation</td>
<td>$38,752</td>
<td>$33,281</td>
</tr>
</tbody>
</table>

(a) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a Bbl of oil equivalent for natural gas is significantly less than the price for a Bbl of oil.

(b) Excludes the effect of commodity derivative settlements.

(c) Includes the per Boe price effect of oil purchases.

(d) Oil sales were 5,563 (MBoe), 3,530 (MBoe), and 3,148 (MBoe) for 2013, 2012, and 2011 respectively.

(e) Includes the effects of the early termination of commodity derivative contracts terminated in 2011 for a cost of $36,779.

(f) Includes ad valorem and severance taxes.

(g) Includes lease operating expenses, district expenses, transportation expenses and processing fees.
Comparison of Results of Operations for the Years Ended December 31, 2013, 2012 and 2011

The variances in our results of operations were due to the following components:

Production

For the year ended December 31, 2013 compared to the year ended December 31, 2012, production volumes increased by 2,665 MBoe, or 32%, primarily due to an increase of 1,141 MBoe from our Oklahoma Panhandle properties acquired in July 2013, 1,108 MBoe from a full year of production from our Permian Basin properties acquired in July and December 2012, and 508 MBoe from a full year of production from our properties in the San Joaquin Basin in California acquired in November 2012, partially offset by a decrease of 146 MBoe of lower production in Michigan due to natural field declines. In 2013, oil, NGLs and natural gas accounted for 51%, 6% and 43% of our production, respectively.

For the year ended December 31, 2012 compared to the year ended December 31, 2011, production volumes increased by 1,281 MBoe, or 18%, primarily due to an increase of 1,112 MBoe from a full year of production from our southwest Wyoming properties acquired in October 2011, 155 MBoe from a full year of production from our eastern Wyoming properties acquired in July 2011, 315 MBoe from our Permian Basin properties acquired in July and December 2012, 92 MBbl of oil from our central Wyoming properties acquired in June 2012, 28 MBoe from our properties in the San Joaquin Basin in California acquired in November 2012 and 42 MBbl of higher production from new wells in Florida, partially offset by a decrease of 411 MBoe of lower production in Michigan due to lower natural gas prices and natural field declines. The remaining decrease was primarily due to natural field declines at our legacy Wyoming properties, and a reduction in our ownership interest in two California fields, partially offset by higher production from a field in California due to additional drilling. In 2012, oil, NGLs and natural gas accounted for 42%, 2% and 56% of our production, respectively.

Oil, NGL and natural gas sales

Total oil, NGL and natural gas sales revenues increased $246.8 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Oil and NGL revenues increased $204.5 million and $18.7 million, respectively, due to higher sales volumes, primarily due to a full year of production from our 2012 acquisitions in Texas, California and Wyoming, production from our Oklahoma properties acquired in July 2013 and higher average realized prices for both oil and NGLs. Realized prices for oil, excluding the effect of derivative instruments, increased $1.49 per Bbl, or 2%, for the year ended December 31, 2013 compared to the year ended December 31, 2012. Realized prices for NGLs increased $7.29 per Bbl, or 26%, for the year ended December 31, 2013 compared to the year ended December 31, 2012. Natural gas revenues also increased by $23.6 million primarily due to higher realized average price during the year. Realized prices for natural gas, excluding the effect of derivative instruments, increased $0.82 per Mcf, or approximately 27%, for the year ended December 31, 2013 compared to the year ended December 31, 2012.

Total oil, NGL and natural gas sales revenues increased $19.5 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. Oil revenues increased $34.0 million due to higher sales volumes, primarily due to oil production from our 2012 acquisitions in Texas, California and Wyoming. NGL revenues decreased $3.5 million primarily due to lower average realized price partially offset by increase in sales volume. Natural gas revenues decreased $11.1 million primarily due to lower natural gas prices partially offset by higher natural gas production primarily from our 2012 acquisitions in Texas. Realized prices for oil, excluding the effect of derivative instruments, decreased $0.40 per Bbl, or less than 1%, for the year ended December 31, 2012 compared to the year ended December 31, 2011. Realized prices for NGLs, decreased $14.04 per Bbl, or 33%, for the year ended December 31, 2012 compared to the year ended December 31, 2011. Realized prices for natural gas, excluding the effect of derivative instruments, decreased $1.18 per Mcf, or approximately 28%, for the year ended December 31, 2012 compared to the year ended December 31, 2011.

Loss on commodity derivative instruments

Loss on commodity derivative instruments for the year ended December 31, 2013 was $29.2 million compared to a gain of $5.6 million for the year ended December 31, 2012. Oil derivative instrument settlements paid for the year ended
December 31, 2013 were $35.5 million compared to settlements received of $3.9 million for the year ended December 31, 2012. Natural gas derivative instrument settlements received for the year ended December 31, 2013 were $43.6 million compared to $83.8 million for the year ended December 31, 2012.

Gain on commodity derivative instruments for the year ended December 31, 2012 was $5.6 million compared to a gain of $81.7 million for the year ended December 31, 2011. Oil derivative instrument settlements received for the year ended December 31, 2012 were $3.9 million compared to settlements paid of $70.4 million for the year ended December 31, 2011. Natural gas derivative instrument settlements received for the year ended December 31, 2012 were $83.7 million compared to $54.3 million for the year ended December 31, 2011. Commodity derivative instrument settlement payments of $16.1 million for the year ended December 31, 2011, included $36.8 million paid to terminate commodity hedge contracts in the fourth quarter of 2011.

Lease operating expenses

Pre-tax lease operating expenses, including processing fees, for the year ended December 31, 2013 totaled $216.3 million, $57.0 million higher than 2012. The increase in pre-tax lease operating expenses was primarily due to the full year effect of the properties acquired in California and Texas during 2012 and partial year effect of the properties acquired in Oklahoma during 2013.

Production and property taxes for the year ended December 31, 2013 totaled $46.2 million, or $4.21 per Boe, which was 4% higher per Boe than the year ended December 31, 2012. The per Boe increase in production and property taxes compared to 2012 was primarily due to higher per Boe production and property taxes on our newly acquired Oklahoma properties due to higher oil prices and an increase in per Boe production and property taxes from our Michigan properties due to higher realized natural gas prices during the year.

Pre-tax lease operating expenses, including processing fees, for the year ended December 31, 2012 totaled $159.3 million, $22.8 million higher than 2011. The increase in pre-tax lease operating expenses reflected our newly acquired Wyoming and Texas properties, higher California well service costs, higher Florida fuel and utilities costs and higher transportation expenses. The increase in California well services was partially offset by lower lease operating expenses at the East Coyote and Sawtelle fields as a result of the reduction in our working interests from 95% to 62% attributable to a payout reversion that was effective April 1, 2012. On a per Boe basis, lease operating expenses were 1% lower than 2011.

Production and property taxes for the year ended December 31, 2012 totaled $33.6 million, or $4.04 per Boe, which was 7% higher per Boe than the year ended December 31, 2011. The per Boe increase in production and property taxes compared to 2011 was primarily due to higher per Boe production and property taxes on our newly acquired Permian Basin assets and an increase in per Boe Florida taxes.

Change in inventory

In Florida, our oil sales are a function of the number and size of oil shipments in each year and thus oil sales do not always coincide with volumes produced in a given year. Sales occur on average every six to eight weeks. We match production expenses with oil sales. Production expenses associated with unsold oil inventory are credited to operating costs through the change in inventory account. Production expenses are charged to operating costs through the change in inventory account when they are sold. In 2013, the change in inventory account amounted to a credit of $1.0 million reflecting the lower amount of barrels sold versus produced during the period. In 2012 and 2011, the change in inventory account amounted to a charge of $1.3 million and $2.0 million, respectively, reflecting the higher amount of barrels sold versus produced during the periods.

Depletion, depreciation and amortization

Depletion, depreciation and amortization (“DD&A”) expense totaled $216.5 million for the year ended December 31, 2013, compared to $137.3 million for the year ended December 31, 2012. The increase in DD&A was primarily due to increased production from our acquired properties in 2013 and the full year effect of properties acquired in 2012. DD&A included $3.6 million in amortization of intangible assets related to CO2 contracts acquired in the
Oklahoma Panhandle Acquisitions. For the year ended December 31, 2013, DD&A was $19.71 per Boe compared to $16.50 per Boe for the year ended December 31, 2012, primarily due to higher rates reflecting 2012 year-end negative reserve adjustments.

DD&A expense totaled $137.3 million, or $16.50 per Boe, for the year ended December 31, 2012, compared to $107.1 million, or $15.22 per Boe, for the year ended December 31, 2011.

Asset Impairments

For the year ended December 31, 2013, we recorded asset impairment charges of $54.4 million, including $28.3 million of impairments to our Michigan non-Antrim oil and gas properties due to negative reserve adjustments due to lower performance and a decrease in expected future commodity prices, and $25.3 million of impairments to an oil property in our Bighorn Basin in Northern Wyoming due to a negative reserve adjustment due to lower performance and a decrease in expected future oil prices. Decreased drilling activity in Michigan was also a factor as the Partnership continues to allocate its capital expenditures more towards liquids-rich areas.

For the year ended December 31, 2012 and 2011, we recorded asset impairment charges of $12.3 million and $0.6 million, respectively. The impairment charge in 2011 reflected uneconomical proved properties in Michigan.

General and administrative expenses

Our G&A expenses totaled $88.7 million and $55.5 million in 2013 and 2012, respectively. This included $20.0 million and $22.2 million, respectively, in unit-based compensation expense related to employee incentive plans. For 2013, G&A expenses, excluding unit-based compensation, were $38.7 million, which was $5.4 million higher than 2012. The increase was primarily due to $4.9 million of acquisition and integration costs. On a per Boe basis, G&A expenses, excluding unit-based compensation, were $3.53 in 2013, which was a 12% decrease from 2012.

Our G&A expenses totaled $55.5 million and $53.2 million in 2012 and 2011, respectively. This included $22.2 million and $22.0 million, respectively, in unit-based compensation expense related to employee incentive plans. For 2012, G&A expenses, excluding unit-based compensation, were $33.3 million, which was $2.1 million higher than 2011. The increase was primarily due to additional G&A expenses related to our 2012 acquisitions. On a per Boe basis, G&A expenses, excluding unit-based compensation, were $4.00 in 2012, which was a 10% decrease from 2011.

Interest expense, net of amounts capitalized

Interest expense totaled $87.1 million for the year ended December 31, 2013, an increase of $25.9 million from 2012. This increase in interest expense was primarily attributable to $15.8 million associated with our 7.875% Senior Notes due 2022, which were issued in September 2012 and November 2013 and approximately $7.7 million of higher interest expense on borrowings under our credit facility during 2013 primarily due to acquisitions.

Our interest expense totaled $61.2 million for the year ended December 31, 2012, an increase of $22.0 million from 2011. This increase in interest expense was primarily attributable to an additional $23.0 million of interest expense associated with our 2022 Senior Notes and slightly higher amortization of debt issuance costs, partially offset by $1.2 million lower interest expense on our credit facility due to lower average credit facility debt balance.

Loss on interest rate swaps

We are subject to interest rate risk associated with loans under our credit facility that bear interest based on floating rates. In order to mitigate our interest rate exposure, we have in the past entered into, and may in the future enter into, interest rate derivative contracts, indexed to 1-month LIBOR, to fix a portion of floating LIBOR-based debt under our credit facility. As of December 31, 2013 and December 31, 2012, we had no interest rate swaps in place. See Part II Item 7A “Quantitative and Qualitative Disclosures About Market Risk” in this report for a discussion of our interest rate risk. Loss on interest swaps for the year ended December 31, 2012 and 2011 were $1.1 million and $2.8 million, respectively.

Liquidity and Capital Resources

65
Our primary sources of liquidity are cash generated from operating activities, amounts available under our credit facility and cash from the issuance of unsecured long-term debt and partnership units. Historically, our primary uses of cash have been for our operating expenses, capital expenditures, acquisitions and cash distributions to unitholders. To fund certain acquisition transactions, we have also sourced the private placement markets and have issued equity as partial consideration for the acquisition of oil and natural gas properties. As market conditions have permitted, we have also engaged in non-core asset sale transactions.

We believe that we have and will continue to have the ability to access our credit facility, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity, however, commodity price volatility that adversely affects our business may have a materially adverse effect on our financial condition, results of operations or cash flows.

**Equity Offerings**

In November 2013, we sold approximately 18.98 million Common Units at a price to the public of $18.22 per Common Unit, resulting in proceeds, net of underwriting discounts and expenses, of $333.2 million.

In February 2013, we sold approximately 14.95 million Common Units at a price to the public of $19.86 per Common Unit, resulting in proceeds, net of underwriting discounts and expenses, of $285.0 million.

In November 2012, we issued 3.01 million Common Units to AEO as partial consideration for the AEO Acquisition. The fair value of the units on the date of the acquisition was $18.48 per Common Unit, or $56.0 million.

In September 2012, we sold 11.50 million Common Units at a price to the public of $18.51 per Common Unit, resulting in proceeds, net of underwriting discount and offering expenses, of $204.1 million.

In February 2012, we sold 9.20 million Common Units at a price to the public of $18.80 per Common Unit, resulting in proceeds, net of underwriting discounts and offering expenses, of $166.0 million.

We primarily used the proceeds from these offerings to reduce borrowings under our credit facility.

**Senior Notes**

In November 2013, we and BreitBurn Finance Corporation, and certain of our subsidiaries as guarantors, issued an additional $400 million aggregate principal amount of our 7.875% Senior Notes due 2022. These notes were offered as an addition to our existing 7.875% Senior Notes due 2022 at a premium of 100.250%. We received net proceeds of approximately $393.4 million, after deducting fees and offering expenses, and excluding proceeds from accrued interest.

In January 2012, we and BreitBurn Finance Corporation, and certain of our subsidiaries as guarantors, issued $250 million in aggregate principal amount of 7.875% senior notes due 2022 at a price of 99.154%. We received net proceeds of approximately $242.3 million, after deducting fees and offering expenses. In September 2012, we issued an additional $200 million aggregate principal amount of our 7.875% Senior Notes due 2022. These notes were offered at a premium of 103.500%. We received net proceeds of approximately $202.8 million, after deducting fees and offering expenses.

As of December 31, 2013, we were in compliance with the covenants of our Senior Notes.

The use of proceeds from the issuance of these senior notes to repay amounts outstanding under our credit facility increased the borrowing availability under our credit facility, which gives us additional flexibility to finance future acquisitions.
Credit Facility

As of December 31, 2013, BOLP, as borrower, and we and our wholly-owned subsidiaries, as guarantors, have a $3.0 billion revolving credit facility with Wells Fargo Bank National Association, as Administrative Agent, Swing Line Lender and Issuing Lender, and a syndicate of banks (the “Second Amended and Restated Credit Agreement”) with a maturity date of May 9, 2016.

Our credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base is redetermined semi-annually. Currently, our borrowing base for our credit facility is $1.5 billion, and the aggregate commitment of all lenders is $1.4 billion with the ability to increase our total commitments up to the $1.5 billion borrowing base upon lender approval. Our next borrowing base redetermination is scheduled for April 2014.

In May 2013, we entered into the Eighth Amendment to the Second Amended and Restated Credit Agreement, which increased our borrowing base to $1.2 billion and the aggregate commitment of all lenders to $1.0 billion, and added eight lenders to our syndicate.

In July 2013, we entered into the Ninth Amendment to the Second Amended and Restated Credit Agreement, which increased our aggregate maximum credit amount from $1.5 billion to $3.0 billion, increased our borrowing base to $1.5 billion and increased the aggregate commitment of all lenders to $1.4 billion. The amendment also increased flexibility for the Total Leverage Ratio (defined as the ratio of total debt to EBITDAX) and added a new Senior Secured Leverage Ratio (defined as the ratio of senior secured indebtedness to EBITDAX). Both of these leverage ratios were eliminated from our credit facility in connection with the Eleventh Amendment (the “Eleventh Amendment”) to the Second Amended and Restated Credit Agreement discussed below.

In November 2013, we entered into the Tenth Amendment to the Second Amended and Restated Credit Agreement, which permitted us to declare and pay to our equity owners periodic cash dividends in accordance with our partnership agreement.

In February 2014, we entered into the Eleventh Amendment to the Second Amended and Restated Credit Agreement that eliminated the Maximum Total Leverage Ratio (defined as the ratio of total debt to EBITDAX) and Maximum Senior Secured Leverage Ratio (defined as the ratio of senior secured indebtedness to EBITDAX) requirements and added a provision requiring us to maintain an Interest Coverage Ratio (defined as EBITDAX divided by Consolidated Interest Expense) for the four quarters ending on the last day of each quarter beginning with the fourth quarter of 2013 of no less than 2.50 to 1.00. The amendment also provides that we cannot incur senior unsecured debt in excess of our borrowing base in effect at the time of the issuance of such debt.

As of December 31, 2013, the lending group under the Second Amended and Restated Credit Agreement included 22 banks. Of the $1,400 million in total commitments under the credit facility, Wells Fargo Bank National Association held approximately 12% of the commitments. Ten banks held between 5% and 7% of the commitments, including Union Bank, N.A., Bank of Montreal, The Bank of Nova Scotia, Houston Branch, Citibank, N.A., Royal Bank of Canada, U.S. Bank National Association, Sovereign Bank, Barclays Bank PLC, The Royal Bank of Scotland plc and JP Morgan Chase, with each of the remaining lenders holding less than 5% of the commitments. In addition to our relationships with these institutions under the credit facility, from time to time we engage in other transactions with a number of these institutions. Such institutions or their affiliates may serve as underwriter or initial purchaser of our debt and equity securities and/or serve as counterparties to our commodity and interest rate derivative agreements.

We had outstanding borrowings under our credit facility of $733.0 million as of December 31, 2013 and $747.0 million as of February 27, 2014.

The Second Amended and Restated Credit Agreement contains customary covenants, including restrictions on our ability to: incur additional indebtedness, make certain investments, loans or advances, make distributions to our unitholders or repurchase units, make dispositions or enter into sales and leasebacks, or enter into a merger or sale of our property or assets, including the sale or transfer of interests in our subsidiaries.
The Second Amended and Restated Credit Agreement also permits us to terminate derivative contracts without obtaining the consent of the lenders in the facility, provided that the net effect of such termination plus the aggregate value of all dispositions of oil and gas properties made during such period, together, does not exceed 5% of the borrowing base, and the borrowing base will be automatically reduced by an amount equal to the net effect of the termination.

The events that constitute an Event of Default (as defined in the Second Amended and Restated Credit Agreement) include: payment defaults, misrepresentations, breaches of covenants, cross-default and cross-acceleration to certain other indebtedness, adverse judgments against us in excess of a specified amount, changes in management or control, loss of permits, certain insolvency events and assertion of certain environmental claims.

EBITDAX is not a defined US GAAP measure. The Second Amended and Restated Credit Agreement defines EBITDAX as consolidated net income plus exploration expense, interest expense, income tax provision, DD&A, unrealized loss or gain on derivative instruments, non-cash charges, including non-cash unit-based compensation expense, loss or gain on sale of assets (excluding gain or loss on monetization of derivative instruments for the following twelve months), pro forma impact of acquisitions and disposition, cumulative effect of changes in accounting principles, cash distributions received from our unrestricted entities (as defined in the Second Amended and Restated Credit Agreement) and excluding income from our unrestricted entities.

As of December 31, 2013, we were in compliance with our credit facility’s covenants.

Please see Part I—Item 1A “—Risk Factors”— “Risks Related to Our Business — Our credit facility has substantial restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions” in this report for more information on the effect of an event of default under the Second Amended and Restated Credit Facility.

**Cash Flows**

**Operating activities.** Our cash flow from operating activities in 2013 was $257.2 million compared to $191.8 million in 2012. The increase in cash flow from operating activities in 2013 was primarily due to higher sales volumes, partially offset by lower net cash settlements on derivative instruments, higher operating costs and higher interest expense. In 2012, we paid $30.0 million in premiums on commodity derivative contracts and $2.5 million to terminate an interest rate contract.

Our cash flow from operating activities in 2012 was $191.8 million compared to $128.5 million in 2011. The increase in cash flow from operating activities in 2012 was primarily due to higher oil sales revenue and higher settlements received on commodity derivatives, partially offset by higher operating costs, higher interest expense and the payment of $30 million in premiums on commodity derivative contracts and $2.5 million for terminate the interest rate contract mentioned in the previous paragraph.

**Investing activities.** Net cash used in investing activities for the year ended December 31, 2013 was $1,465.8 million, which was predominantly spent on property acquisitions. Property acquisitions of $1,175.8 million in 2013 primarily included $875.5 for the Oklahoma Panhandle Acquisitions and $302.1 million for the 2013 Permian Basin Acquisitions. We also spent $266.3 million for capital expenditures, primarily for drilling and completions. In addition, we spent $11.7 million in advances made for the purchase of future CO₂ supply for our Oklahoma properties, and $15.0 million deposit related to negotiations undertaken to secure additional future CO₂ supply. Net cash used in investing activities for the year ended December 31, 2012 was $697.2 million which was predominantly spent on property acquisitions. Property acquisitions of $562.4 million in 2012 included $420 million for the Permian Basin Acquisitions, $95 million for the NiMin Acquisition and $38 million for the AEO Acquisition. We also spent $135.9 million for capital expenditures, primarily for drilling and completions.

Net cash used in investing activities for the year ended December 31, 2011 was $414.6 million which was predominantly spent on property acquisitions. Property acquisitions of $338.8 million in 2011 included $280.6 million for the Cabot Acquisition and $57.4 million for the Greasewood Acquisition. We also spent $78.1 million for capital expenditures, primarily for drilling and completions.
Financing activities. Net cash provided by financing activities for the year ended December 31, 2013 was $1,206.6 million compared to $504.6 million for the year ended December 31, 2012. Our long-term debt increased by approximately $789.0 million in 2013 compared to $279.9 million in 2012. The increase in our debt in 2013 and 2012 was primarily due to borrowings for property acquisitions. In addition, for the year ended December 31, 2013, we received net cash proceeds from the issuance of Common Units of $618.0 million, made cash distributions of $186.9 million and paid $15.6 million in debt issuance costs. For the year ended December 31, 2012, we received net cash proceeds from the issuance of Common Units of $370.2 million, made cash distributions of $132.4 million and paid $10.0 million in debt issuance costs.

Net cash used in financing activities for the year ended December 31, 2011 was $287.7 million. We received net cash proceeds from the issuance of Common Units of $99.4 million, made cash distributions of $102.7 million and paid $3.7 million in debt issuance costs. Our long-term debt increased by approximately $292.0 million in 2011 primarily due to borrowings for property acquisitions.

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements as of December 31, 2013.

Contractual Obligations and Commitments

The following table summarizes our financial contractual obligations as of December 31, 2013. Some of these contractual obligations are reflected in the balance sheet, while others are disclosed as future obligations under US GAAP.

<table>
<thead>
<tr>
<th>Payments Due by Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Thereafter</th>
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<tr>
<td>Credit facility (a)</td>
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<td>—</td>
<td>$</td>
<td>$733,000</td>
<td>$</td>
<td>—</td>
<td>$</td>
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<tr>
<td>Credit facility commitment fees</td>
<td>2,906</td>
<td>2,906</td>
<td>1,027</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>6,839</td>
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<tr>
<td>Senior Notes (b)</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>1,155,000</td>
<td>1,155,000</td>
</tr>
<tr>
<td>Estimated interest payments (c)</td>
<td>109,513</td>
<td>109,513</td>
<td>99,171</td>
<td>93,244</td>
<td>93,244</td>
<td>267,468</td>
<td>772,153</td>
</tr>
<tr>
<td>Operating lease obligations</td>
<td>5,910</td>
<td>5,530</td>
<td>4,498</td>
<td>4,068</td>
<td>633</td>
<td>—</td>
<td>20,639</td>
</tr>
<tr>
<td>Asset retirement obligations (d)</td>
<td>—</td>
<td>2,477</td>
<td>1,014</td>
<td>21</td>
<td>3,064</td>
<td>117,193</td>
<td>123,769</td>
</tr>
<tr>
<td>Deferred premiums</td>
<td>657</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>657</td>
</tr>
<tr>
<td>Purchase obligations</td>
<td>$15,790</td>
<td>$28,942</td>
<td>$14,638</td>
<td>$15,663</td>
<td>$21,487</td>
<td>$45,353</td>
<td>$141,873</td>
</tr>
<tr>
<td>Total</td>
<td>$134,776</td>
<td>$149,368</td>
<td>$853,348</td>
<td>$112,996</td>
<td>$118,428</td>
<td>$1,585,014</td>
<td>$2,953,930</td>
</tr>
</tbody>
</table>

(a) Credit facility matures on May 9, 2016.
(b) Represents 8.625% senior notes due 2020 with a face value of $305 million and 7.875% Senior Notes due 2022 with a face value of $850 million.
(c) Based on debt balance and interest rates in effect at December 31, 2013.
(d) Amounts represent our estimate of future asset retirement obligations on a discounted basis. See Note 13 to the consolidated financial statements in this report.

Surety Bonds and Letters of Credit

In the normal course of business, we have performance obligations that are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily relate to abandonments, environmental and other responsibilities where governmental and other organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by us if drawn upon. At December 31, 2013, we had $17.5 million in surety bonds and $2.8 million in letters of credit outstanding. At December 31, 2012, we had $16.2 million in surety bonds and $0.3 million in letters of credit outstanding.
Credit and Counterparty Risk

Financial instruments that potentially subject us to concentrations of credit risk consist principally of derivatives and accounts receivable. Our derivatives are exposed to credit risk from counterparties. As of December 31, 2013 and February 27, 2014, our derivative counterparties were Barclays Bank PLC, Bank of Montreal, Citibank, N.A, Credit Suisse Energy LLC, Union Bank N.A, Wells Fargo Bank National Association, JP Morgan Chase Bank N.A., The Royal Bank of Scotland plc, The Bank of Nova Scotia, BNP Paribas, Toronto-Dominion Bank and the Royal Bank of Canada. Our counterparties are all lenders who participate in our Second Amended and Restated Credit Agreement. During 2008 and 2009, there was extreme volatility and disruption in the capital and credit markets. While the market has become more stable, future volatility could adversely affect the financial condition of our derivative counterparties. On all transactions where we are exposed to counterparty risk, we analyze the counterparty’s financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We periodically obtain credit default swap information on our counterparties. As of December 31, 2013 and February 27, 2014, each of these financial institutions had an investment grade credit rating. Although we currently do not believe we have a specific counterparty risk with any party, our loss could be substantial if any of these parties were to default. As of December 31, 2013, our largest derivative asset balances were with Wells Fargo Bank National Association, Credit Suisse Energy LLC and Citibank, N.A., which accounted for approximately 30%, 26% and 13% of our derivative asset balances, respectively. See Note 4 to the consolidated financial statements in this report for more information regarding our derivatives.

Accounts receivable are primarily from purchasers of oil and natural gas products. We have a portfolio of oil, NGL and natural gas sales contracts with large, established refiners and utilities. Because our products are commodity products sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. For the years ended December 31, 2013, 2012 and 2011, we sold oil, NGL and natural gas production representing 10% or more of total revenue to the following purchasers:

<table>
<thead>
<tr>
<th>Purchaser</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phillips 66 (a)</td>
<td>15%</td>
<td>16%</td>
<td>—%</td>
</tr>
<tr>
<td>Shell Trading</td>
<td>15%</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>Marathon Oil Corporation</td>
<td>10%</td>
<td>14%</td>
<td>15%</td>
</tr>
<tr>
<td>Plains Marketing &amp; Transportation LLC</td>
<td>9%</td>
<td>17%</td>
<td>16%</td>
</tr>
<tr>
<td>ConocoPhillips</td>
<td>5%</td>
<td>14%</td>
<td>30%</td>
</tr>
</tbody>
</table>

(a) During 2012, Phillips 66 and ConocoPhillips became two separate entities.

Our sales contracts are sold at market-sensitive or spot prices. Because commodity products are sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. As a result, the loss of any one purchaser would not have a long-term material adverse effect on our ability to sell our production.

Phillips 66 and Shell Trading each comprised 10% or more of our outstanding trade receivables, and together comprised approximately 33% of our outstanding trade receivables as of December 31, 2013.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with US GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.
and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. The development, selection and disclosure of each of these policies is reviewed by our audit committee. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of our financial statements. See Note 2 to the consolidated financial statements in this report for a discussion of additional accounting policies and estimates made by management.

**Successful Efforts Method of Accounting**

We account for oil and gas properties using the successful efforts method. Under this method of accounting, leasehold acquisition costs are capitalized. Subsequently, if proved reserves are found on unproved property, the leasehold costs are transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

DD&A of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Acquisition costs of proved properties are amortized on the basis of all proved reserves, both developed and undeveloped, and capitalized development costs (wells and related equipment and facilities) are amortized on the basis of proved developed reserves.

Geological, geophysical and dry hole costs on oil and gas properties relating to unsuccessful exploratory wells are charged to expense as incurred.

Oil and gas properties are reviewed for impairment periodically and when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. For purposes of performing an impairment test, the undiscounted cash flows are forecast using five-year NYMEX forward strip prices at the end of the period and escalated thereafter at 2.5%. For impairment charges, the associated property’s expected future net cash flows are discounted using a weighted average cost of capital which approximated 10% at December 31, 2013. Reserves are calculated based upon reports from third party engineers adjusted for acquisitions or other changes occurring during the year as determined to be appropriate in the good faith judgment of management. Unproved properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred.

We capitalize interest costs to oil and gas properties on expenditures made in connection with certain projects such as drilling and completion of new oil and natural gas wells and major facility installations. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the units of production method.

The Partnership carries out tertiary recovery methods on certain of its oil and gas properties in Oklahoma in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Acquisition costs of tertiary injectants, such as purchased CO₂, for enhanced oil recovery (“EOR”) activities that are used prior to the recognition of proved tertiary recovery reserves are expensed as incurred. After a project has been determined to be technically feasible and economically viable, all acquisition costs of tertiary injectants are capitalized as development costs and depleted, as they are incurred solely for obtaining access to reserves not otherwise recoverable and have future economic benefits over the life of the project. As CO₂ is recovered together with oil and gas production, it is extracted and re-injected, and all the associated CO₂ recycling costs are expensed as incurred. Likewise, costs incurred to maintain reservoir pressure are also expensed.

**Business combinations**

We account for all business combinations using the acquisition method. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether
in the form of cash, assets, equity or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if material, is recognized as a gain at the time of acquisition. All purchase price allocations are finalized within one year from the acquisition date. We have not recognized any goodwill from any of our business combinations.

**Oil and Gas Reserve Quantities**

The estimates of our proved reserves are based on the quantities of oil, NGLs and gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Annually, CGA, NSAI and SLB prepare reserve and economic evaluations of all our properties on a well-by-well basis.

Estimated proved reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepare our disclosures for reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firms described above adhere to the same guidelines when preparing their reserve reports. The accuracy of the reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil, NGLs and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify, positively or negatively, material revisions to the estimate of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of producing properties for impairment. For example, if the SEC prices used for our December 31, 2013 reserve report had been $10.00 less per Bbl and $1.00 less per MMBtu, respectively, then the standardized measure of our estimated proved reserves as of December 31, 2013 would have decreased by approximately $1.7 billion, from $3.2 billion to $1.5 billion.

Please see Part I—Item 1A —“Risk Factors” — “Risks Related to Our Business — Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves.”

**Asset Retirement Obligations**

Estimated asset retirement obligation (“ARO”) costs are recognized when the asset is placed in service and are amortized over proved reserves using the units of production method. The engineers of BreitBurn Management estimate asset retirement costs using existing regulatory requirements and anticipated future inflation rates. Projecting future ARO cost estimates is difficult as it involves the estimation of many variables such as economic recoveries of future oil and gas reserves, future labor and equipment rates, future inflation rates, and our credit adjusted risk free interest rate. Because of the intrinsic uncertainties present when estimating asset retirement costs as well as asset retirement settlement dates, our ARO estimates are subject to ongoing volatility.

**Derivative Instruments**

We use derivative financial instruments to achieve more predictable cash flow from our oil and natural gas production by reducing their exposure to price fluctuations. Currently, these instruments include swaps, collars and options. Additionally, we may use derivative financial instruments in the form of interest rate swaps to mitigate interest rate exposure. Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded at fair market value and are included in the balance sheet as assets or liabilities. The accounting for changes in the fair
market value of a derivative instrument depends on the intended use of the derivative instrument and the resulting designation, which is established at the inception of a derivative instrument. We do not account for our derivative instruments as cash flow hedges for financial accounting purposes and are recognizing changes in the fair value of our derivative instruments immediately in net income. See Part II—Item 7A “—Quantitative and Qualitative Disclosures About Market Risk” and Note 4 to the consolidated financial statements in this report for additional information related to our financial instruments.

New Accounting Standards

There are no new accounting standards issued but not yet effective that are expected to have a material impact on our financial position, results of operations or cash flows.
Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. See “Cautionary Statement Regarding Forward-Looking Information” in Part I—Item 1 “—Business” in this report.

See Note 4 to the consolidated financial statements in this report for additional information related to our financial instruments, including summaries of our commodity and interest rate derivative contracts at December 31, 2013 and a discussion of credit and counterparty risk.

Commodity Price Risk

Due to the historical volatility of oil and natural gas prices, we have entered into various derivative instruments to manage exposure to volatility in the market price of oil and natural gas to achieve more predictable cash flows. We use swaps, collars and options for managing risk relating to commodity prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in us having lower revenues than we would otherwise have if we had not utilized these instruments in times of higher oil and natural gas prices, management believes that the resulting reduced volatility of prices and cash flow is beneficial. While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow and distributions, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected. Please see Part I—Item 1A — “Risk Factors” — “Risks Related to Our Business — Our derivative activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders. To the extent we have hedged a significant portion of our expected production and actual production is lower than expected or the costs of goods and services increase, our profitability would be adversely affected.” The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts.

Our commodity derivative instruments provide for monthly settlement based on the differential between the agreement price and the actual ICE Brent oil price, NYMEX WTI oil price, NYMEX Henry Hub natural gas price or MichCon City-Gate natural gas price.

We do not currently designate any of our derivative instruments as hedges for financial accounting purposes. In order to qualify for hedge accounting, the relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge effectiveness must be measured, at minimum, on a quarterly basis. Hedge accounting must be discontinued prospectively when a hedge instrument is no longer considered to be highly effective. Many of our commodity derivative instruments would not qualify for hedge accounting due to the ineffectiveness created by variability in our price discounts or differentials.

Our Oklahoma oil traded at a discount to WTI spot prices primarily due to transportation and quality and our Oklahoma NGLs traded at a discount due to regional market demand and transportation. Our Texas oil traded at a discount to WTI spot prices due to the deduction of transportation costs and our Texas NGLs traded at a discount due to processing fees, profit sharing and transportation. Our California oil is generally medium gravity crude. Because of its proximity to the extensive Los Angeles refining market, it has traded at only a minor discount to WTI in the past. Historically, WTI oil prices and ICE Brent oil prices have traded with only a narrow margin. Increasing supply into Cushing starting in early 2011 resulted in transportation bottlenecks which have led to divergence in the two major world oil benchmarks that has continued to the present. With the California market largely isolated from Cushing, management believes that ICE Brent pricing will better correlate with local California prices we receive until such time as the transportation infrastructure issues at Cushing are resolved. In 2013, ICE Brent prices were higher than WTI, and our California production traded at a premium to WTI. Our Wyoming oil, while generally of similar quality to our Los Angeles Basin oil trades at a significant discount to WTI because of its distance from a major refining market and the

74
fact that our central Wyoming production is priced relative to the Western Canadian Select benchmark. Our eastern Wyoming production is priced relative to Flint Hills Resources Wyoming Sweet posting, both of which have historically traded at a significant discount to WTI spot price. Our Florida oil also traded at a discount to WTI spot price primarily because the oil is transported via barge.

In 2013, the WTI spot price averaged approximately $98 per Bbl, compared with about $94 a year earlier. Monthly average WTI spot prices during 2013 ranged from a low of $92 per Bbl in April to a high of $107 per Bbl in August. During 2013, the average differentials per barrel to WTI spot prices were a $8.03 discount for our Oklahoma-based production, a $4.70 discount for our Texas-based production, a $19.67 discount for our Wyoming-based production, a $7.41 premium for our California-based production and a $2.38 discount for our Florida-based production. In 2013, our average NGL realized price was $35.25 per Boe.

Our Michigan properties have favorable natural gas supply and demand characteristics as the state has been importing an increasing percentage of its natural gas. This supply and demand situation has allowed us to sell our natural gas production at a slight premium to Henry Hub spot prices. Our Wyoming natural gas generally trades at a discount to Henry Hub due to its relative location and the regional supply and demand market balances. Prices for natural gas have historically fluctuated widely and in many regional markets are aligned with supply and demand conditions in regional markets and with the overall U.S. market. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage relative to customer demand. U.S. natural gas prices are also typically higher during the winter period when demand for heating is greatest. During 2013, the monthly average Henry Hub spot price ranged from a low of $3.33 per MMBtu in February to a high of $4.23 per MMBtu in December. During 2013, the Henry Hub spot price averaged approximately $3.73 per MMBtu and the differentials per Mcf to the Henry Hub spot price were a $0.19 premium for our Michigan-based production, a $0.09 premium for our Wyoming-based production and a $0.45 discount for our Texas-based production.

During 2012, the average differentials per barrel to WTI spot prices were a $13.30 premium for our California-based oil production, a $17.55 discount for our Wyoming-based oil production, a $4.91 discount for our Texas-based oil production and a $2.91 premium for our Florida-based oil production, excluding transportation costs. During 2012, the average differentials per Mcf to Henry Hub spot prices were a $0.21 premium for our Michigan-based natural gas production, an $0.18 premium for our Wyoming-based natural gas production and a $1.78 premium for our Texas-based natural gas production.

During 2011, the average differentials per barrel to WTI spot prices were a $13.88 premium for our California-based oil production, a $15.42 discount for our Wyoming-based oil production and a $14.46 discount for our Florida-based oil production, including approximately $7.50 in transportation costs. During 2011, the average differentials per Mcf to Henry Hub spot prices were a $0.27 premium for our Michigan-based natural gas production and a $0.01 discount for our Wyoming-based natural gas production.

All of our derivative instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or confirmed by the counterparty. Changes in the fair value of our commodity derivatives were recorded in the “gain or loss on commodity derivative instruments, net” line on our consolidated statements of operations.

**Interest Rate Risk**

We are subject to interest rate risk associated with loans under our credit facility that bear interest based on floating rates. At December 31, 2013, LIBOR based long-term debt outstanding under our credit facility was $727 million. For the year ended December 31, 2013, our weighted average credit facility debt balance was $520 million and if interest rates on our LIBOR based debt increased or decreased by 1%, our annual interest cost would have increased or decreased by approximately $5.2 million.
Changes in Fair Value

The fair value of our outstanding oil and gas commodity derivative instruments at December 31, 2013 was a net asset of approximately $51.8 million. The fair value of our outstanding oil and gas commodity derivative instruments at December 31, 2012 was a net asset of approximately $79.2 million.

As of December 31, 2013, assuming a $10 per barrel increase in the price of oil and a corresponding $1 per Mcf increase in natural gas, our net commodity derivative instrument asset at December 31, 2013 would have decreased by approximately $227.2 million. Assuming a $10 per barrel decrease in the price of oil and a corresponding $1 per Mcf decrease in natural gas, our net commodity derivative instrument asset at December 31, 2013 would have increased by approximately $230.2 million.

Price risk sensitivities were calculated by assuming across-the-board increases in price of $10 per barrel for oil and $1 per Mcf for natural gas regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of actual changes in prompt month prices equal to the assumptions, the fair value of our derivative portfolio would typically change by less than the amounts given due to lower volatility in out-month prices.

Item 8. Financial Statements and Supplementary Data.

The information required by this Item 8 is incorporated herein by reference from the consolidated financial statements beginning on page F-1.

Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our General Partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our General Partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure, and that such information is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Commission. Based upon the evaluation, our General Partner's principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2013 at the reasonable assurance level.

Management’s Report on Internal Control Over Financial Reporting

The information required by this Item is incorporated by reference from “Management’s Report on Internal Control Over Financial Reporting” located on page F-2.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2013 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.
There was no information required to be disclosed in a report on Form 8-K during the fourth quarter of 2013 that has not previously been reported.
PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Information concerning our directors, executive officers and corporate governance required by this Item is incorporated by reference to the material appearing in our Proxy Statement for the 2014 Annual Meeting of Unitholders (“2014 Proxy Statement”). The 2014 Annual Meeting of Unitholders is to be held on June 19, 2014.

The Board has established an audit committee and determined which members are our “audit committee financial experts.” The information required by this Item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2013.

We have adopted a Code of Ethics for Chief Executive Officers and Senior Officers. It is available on our website at http://ir.breitburn.com/documentdisplay.cfm?DocumentID=804.

Directors and Executive Officers of BreitBurn GP, LLC

The following table sets forth certain information with respect to the members of the board of directors and the executive officers of our General Partner. Executive officers and directors will serve until their successors are duly appointed or elected.

<table>
<thead>
<tr>
<th>Name</th>
<th>Age</th>
<th>Position with BreitBurn GP, LLC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Halbert S. Washburn</td>
<td>53</td>
<td>Chief Executive Officer, Director</td>
</tr>
<tr>
<td>Mark L. Pease</td>
<td>57</td>
<td>President and Chief Operating Officer</td>
</tr>
<tr>
<td>James G. Jackson</td>
<td>49</td>
<td>Executive Vice President and Chief Financial Officer</td>
</tr>
<tr>
<td>Gregory C. Brown</td>
<td>62</td>
<td>Executive Vice President, General Counsel and Chief Administrative Officer</td>
</tr>
<tr>
<td>W. Jackson Washburn</td>
<td>51</td>
<td>Senior Vice President</td>
</tr>
<tr>
<td>David D. Baker</td>
<td>41</td>
<td>Senior Vice President</td>
</tr>
<tr>
<td>Bruce D. McFarland</td>
<td>57</td>
<td>Vice President and Treasurer</td>
</tr>
<tr>
<td>Lawrence C. Smith</td>
<td>60</td>
<td>Vice President, Controller and Chief Accounting Officer</td>
</tr>
<tr>
<td>John R. Butler, Jr.*</td>
<td>75</td>
<td>Chairman of the Board</td>
</tr>
<tr>
<td>Randall H. Breitenbach</td>
<td>53</td>
<td>Vice Chairman of the Board</td>
</tr>
<tr>
<td>David B. Kilpatrick*</td>
<td>64</td>
<td>Director</td>
</tr>
<tr>
<td>Gregory J. Moroney*</td>
<td>62</td>
<td>Director</td>
</tr>
<tr>
<td>Charles S. Weiss*</td>
<td>61</td>
<td>Director</td>
</tr>
</tbody>
</table>

* Independent Directors

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires the directors and executive officers of our General Partner, and persons who own more than 10% of a registered class of our equity securities (collectively, “Insiders”), to file reports of beneficial ownership on Form 3 and reports of changes in beneficial ownership on Form 4 or Form 5 with the SEC. Based solely on our review of the reporting forms and written representations provided to us from the individuals required to file reports, we believe that each of our executive officers and directors has complied with the applicable reporting requirements for transactions in our securities during the fiscal year ended December 31, 2013, except a report of a change in beneficial ownership on Form 4 was not timely filed by Mr. Baker related to his grant of restricted phantom units on April 23, 2013.
Item 11. Executive Compensation.

The information required by this Item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2013.


The information required by this Item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2013.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2013:

<table>
<thead>
<tr>
<th>Plan category, thousands</th>
<th>Number of securities to be issued upon exercise of outstanding options, warrants and rights</th>
<th>Weighted-average exercise price of outstanding options, warrants and rights</th>
<th>Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity compensation plans approved by security holders</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Equity compensation plans not approved by security holders - Partnership LTIP</td>
<td>942 (1)</td>
<td>N/A (2)</td>
<td>5,466 (3)</td>
</tr>
<tr>
<td>Total</td>
<td>942</td>
<td>N/A</td>
<td>5,466</td>
</tr>
</tbody>
</table>

(1) Represents the number of units issued under the Partnership First Amended and Restated 2006 Long-Term Incentive Plan (“Partnership LTIP”).

(2) Unit awards under the Partnership LTIP and the BreitBurn Management Long Term Incentive Plan vest without payment by recipients.

(3) The Partnership LTIP provides that the Board or a committee of the Board may award restricted units, performance units, unit appreciation rights or other unit-based awards and unit awards.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required by this Item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2013.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2013.
PART IV


(a) (1) Financial Statements

See “Index to the Consolidated Financial Statements” set forth on Page F-1.

(2) Financial Statement Schedules

All schedules are omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

80
<table>
<thead>
<tr>
<th>NUMBER</th>
<th>DOCUMENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.1</td>
<td>Certificate of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to Amendment No. 1 to Form S-1 (File No. 333-134049) filed on July 13, 2006).</td>
</tr>
<tr>
<td>3.2</td>
<td>First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 16, 2006).</td>
</tr>
<tr>
<td>3.3</td>
<td>Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).</td>
</tr>
<tr>
<td>3.4</td>
<td>Amendment No. 2 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed April 9, 2009).</td>
</tr>
<tr>
<td>3.5</td>
<td>Amendment No. 3 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed September 1, 2009).</td>
</tr>
<tr>
<td>3.6</td>
<td>Amendment No. 4 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on April 9, 2010).</td>
</tr>
<tr>
<td>3.7</td>
<td>Amendment No. 5 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on November 5, 2013).</td>
</tr>
<tr>
<td>3.8</td>
<td>Fourth Amended and Restated Limited Liability Company Agreement of BreitBurn GP, LLC dated as of April 5, 2010 (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K (File No. 001-33055) filed on April 9, 2011).</td>
</tr>
<tr>
<td>3.9</td>
<td>Amendment No. 1 to the Fourth Amended and Restated Limited Liability Company Agreement of BreitBurn GP, LLC dated as of December 30, 2010 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on January 6, 2011).</td>
</tr>
<tr>
<td>4.1</td>
<td>Indenture, dated as of October 6, 2010, by and among BreitBurn Energy Partners L.P., BreitBurn Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 7, 2010).</td>
</tr>
<tr>
<td>4.4</td>
<td>Registration Rights Agreement, dated as of September 27, 2012, by and among BreitBurn Energy Partners L.P., BreitBurn Finance Corporation, the Guarantors named therein and Wells Fargo Securities, LLC, as representative of the Initial Purchasers named therein (incorporated herein by reference to Exhibit 4.2 to the Current Report on Form 8-K (File No. 001-33055) filed on September 28, 2012).</td>
</tr>
<tr>
<td>4.5</td>
<td>First Supplemental Indenture, dated as of August 8, 2013, by and among BreitBurn Energy Partners L.P., BreitBurn Finance Corporation, the Guarantors named therein and U.S. Bank National Association, to the Indenture, dated as of October 6, 2010 (incorporated herein by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-33055) filed on November 22, 2013).</td>
</tr>
</tbody>
</table>

10.2 Amendment No. 1 to the Operations and Proceeds Agreement, relating to the Dominguez Field and dated October 10, 2006 entered into on June 17, 2008 by and between BreitBurn Energy Company L.P. and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.6 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).

10.3 Amendment No. 1 to the Surface Operating Agreement dated October 10, 2006 entered into on June 17, 2008 by and between BreitBurn Energy Company L.P. and its predecessor BreitBurn Energy Corporation and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.7 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).

10.4† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreement (Employment Agreement Form) (incorporated herein by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the period ended June 30, 2008 (File No. 0001-33055) and filed on August 11, 2008).

10.5† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreement (Non-Employment Agreement Form) (incorporated herein by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the period ended June 30, 2008 and (File No. 0001-33055) filed on August 11, 2008).


10.7 Indemnity Agreement between BreitBurn Energy Partners L.P., BreitBurn GP, LLC and Halbert S. Washburn, together with a schedule identifying other substantially identical agreements between BreitBurn Energy Partners L.P., BreitBurn GP, LLC and each of its executive officers and non-employee directors identified on the schedule (incorporated herein by reference to Exhibit 10.1 to the Current Report on form 8-K (File No. 0001-33055) filed on November 4, 2009).

10.8† First Amendment to the BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreements (incorporated herein by reference to Exhibit 10.2 to the Current Report on form 8-K (File No. 0001-33055) filed on November 4, 2009).

10.9† First Amended and Restated BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan effective as of October 29, 2009 (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the period ended September 30, 2009 (File No. 0001-33055) filed on November 6, 2009).

10.10† First Amendment to the First Amended and Restated BreitBurn Energy Partners L.P. 2006 Long Term Incentive Plan (incorporated herein by reference to Exhibit 10.2 to the Form S-8 Registration Statement (File No. 333-181526) filed on May 18, 2012).

10.11† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Executive Form) (incorporated herein by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).


10.13† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Director Form) (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).

10.14† Form of Second Amendment to the BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreements (incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).

10.15† Form of Third Amendment to the BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreements (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).


10.20    Second Amended and Restated Credit Agreement, dated May 7, 2010, by and among BreitBurn Operating L.P., as borrower, BreitBurn Energy Partners L.P., as parent guarantor, and Wells Fargo Bank, N.A., as administrative agent (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the period ended March 31, 2010 (File No. 001-33055) filed on May 10, 2010).

10.21    First Amendment dated September 17, 2010 to the Second Amended and Restated Credit Agreement dated May 7, 2010, by and among BreitBurn Operating L.P., as borrower, BreitBurn Energy Partners L.P., as parent guarantor, and Wells Fargo Bank, N.A., as administrative agent (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on September 23, 2010).

10.22    Second Amendment to the Second Amended and Restated Credit Agreement dated May 9, 2011 (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-33055) filed on May 10, 2011).

10.23    Third Amendment to the Second Amended and Restated Credit Agreement dated August 3, 2011 (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (File No. 001-33055) filed on August 8, 2011).

10.24    Fourth Amendment to the Second Amended and Restated Credit Agreement dated October 5, 2011 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 7, 2011).

10.25    Eighth Amendment to the Second Amended and Restated Credit Agreement dated May 22, 2013 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on July 18, 2013).

10.26    Ninth Amendment to the Second Amended and Restated Credit Agreement dated July 15, 2013 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on July 18, 2013).

10.27*    Tenth Amendment to the Second Amended and Restated Credit Agreement dated November 6, 2013.

10.28*    Eleventh Amendment to the Second Amended and Restated Credit Agreement dated February 21, 2014.


Fifth Amendment to the Second Amended and Restated Credit Agreement, dated as of May 25, 2012 (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on June 29, 2012).

Sixth Amendment to the Second Amended and Restated Credit Agreement, dated as of October 11, 2012 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 16, 2012).


Purchase and Sale Agreement, dated December 11, 2012, between Lynden USA Inc. and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on December 12, 2012).

Form of First Amendment to BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Director Form) (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on December 14, 2012).
<table>
<thead>
<tr>
<th>NUMBER</th>
<th>DOCUMENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.46†</td>
<td>Form of Fourth Amendment to BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreement (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on December 14, 2012).</td>
</tr>
<tr>
<td>10.48*†</td>
<td>Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Employment Agreement Form) for 2014 grants.</td>
</tr>
<tr>
<td>10.49*†</td>
<td>Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (For Directors) for 2014 grants.</td>
</tr>
<tr>
<td>10.50*†</td>
<td>Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Deferred Payment Award) for 2014 grants.</td>
</tr>
<tr>
<td>10.51</td>
<td>Purchase and Sale Agreement dated June 22, 2013, by and between Whiting Oil and Gas Corporation and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on June 25, 2013).</td>
</tr>
<tr>
<td>10.53</td>
<td>Seventh Amendment to the Second Amended and Restated Credit Agreement dated February 26, 2013 (incorporated herein by reference to Exhibit 10.1 to the Annual Report on Form 10-K (File No. 001-33055) filed on February 28, 2013).</td>
</tr>
<tr>
<td>21.1*</td>
<td>List of subsidiaries of BreitBurn Energy Partners L.P.</td>
</tr>
<tr>
<td>23.1*</td>
<td>Consent of PricewaterhouseCoopers LLP.</td>
</tr>
<tr>
<td>23.2*</td>
<td>Consent of Netherland, Sewell &amp; Associates, Inc.</td>
</tr>
<tr>
<td>23.3*</td>
<td>Consent of Schlumberger PetroTechnical Services.</td>
</tr>
<tr>
<td>23.4*</td>
<td>Consent of Cawley, Gillespie &amp; Associates, Inc.</td>
</tr>
<tr>
<td>32.1**</td>
<td>Certification of Registrant’s Chief Executive Officer pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002.</td>
</tr>
<tr>
<td>32.2**</td>
<td>Certification of Registrant’s Chief Financial Officer pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002.</td>
</tr>
<tr>
<td>99.2*</td>
<td>Schlumberger PetroTechnical Services reserve report.</td>
</tr>
<tr>
<td>99.3*</td>
<td>Cawley, Gillespie &amp; Associates, Inc. reserve report.</td>
</tr>
<tr>
<td>101.INS*</td>
<td>XBRL Instance Document.</td>
</tr>
<tr>
<td>101.CAL*</td>
<td>XBRL Taxonomy Extension Calculation Linkbase Document.</td>
</tr>
<tr>
<td>101.DEF*</td>
<td>XBRL Taxonomy Extension Definition Linkbase Document.</td>
</tr>
<tr>
<td>101.LAB*</td>
<td>XBRL Taxonomy Extension Label Linkbase Document.</td>
</tr>
<tr>
<td>101.PRE*</td>
<td>XBRL Taxonomy Extension Presentation Linkbase Document.</td>
</tr>
</tbody>
</table>
* Filed herewith.
** Furnished herewith.
† Management contract or compensatory plan or arrangement.
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BREITBURN ENERGY PARTNERS L.P.

By: BREITBURN GP, LLC, its General Partner

Dated: February 28, 2014

By: /s/ Halbert S. Washburn

Halbert S. Washburn
Chief Executive Officer

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

<table>
<thead>
<tr>
<th>Name</th>
<th>Title</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>/s/ Halbert S. Washburn</td>
<td>Chief Executive Officer and Director of BreitBurn GP, LLC (Principal Executive Officer)</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>Halbert S. Washburn</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ James G. Jackson</td>
<td>Chief Financial Officer of BreitBurn GP, LLC (Principal Financial Officer)</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>James G. Jackson</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ Lawrence C. Smith</td>
<td>Vice President and Controller of BreitBurn GP, LLC (Principal Accounting Officer)</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>Lawrence C. Smith</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ John R. Butler, Jr.</td>
<td>Chairman of the Board of BreitBurn GP, LLC</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>John R. Butler, Jr.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ Randall H. Breitenbach</td>
<td>Vice Chairman of the Board BreitBurn GP, LLC</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>Randall H. Breitenbach</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ David B. Kilpatrick</td>
<td>Director of BreitBurn GP, LLC</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>David B. Kilpatrick</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ Gregory J. Moroney</td>
<td>Director of BreitBurn GP, LLC</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>Gregory J. Moroney</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ Charles S. Weiss</td>
<td>Director of BreitBurn GP, LLC</td>
<td>February 28, 2014</td>
</tr>
<tr>
<td>Charles S. Weiss</td>
<td></td>
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<tr>
<td>---------------------------------------------------------------</td>
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<tr>
<td>Report of Independent Registered Public Accounting Firm</td>
<td>F-3</td>
<td></td>
</tr>
<tr>
<td>Consolidated Balance Sheets</td>
<td>F-4</td>
<td></td>
</tr>
<tr>
<td>Consolidated Statements of Operations</td>
<td>F-5</td>
<td></td>
</tr>
<tr>
<td>Consolidated Statements of Cash Flows</td>
<td>F-6</td>
<td></td>
</tr>
<tr>
<td>Consolidated Statements of Partners’ Equity</td>
<td>F-7</td>
<td></td>
</tr>
<tr>
<td>Notes to Consolidated Financial Statements</td>
<td>F-8</td>
<td></td>
</tr>
<tr>
<td>Supplemental Information</td>
<td>F-37</td>
<td></td>
</tr>
<tr>
<td>Exhibit Index</td>
<td>F-44</td>
<td></td>
</tr>
</tbody>
</table>

F-1
Management’s Report on Internal Control Over Financial Reporting

The management of BreitBurn Energy Partners, L.P. (the “Partnership”) is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. The term “internal control over financial reporting” is defined as a process designed by, or under the supervision of, the Partnership’s principal executive and principal financial officers, or persons performing similar functions, and effected by the Partnership’s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Partnership; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership’s assets that could have a material effect on the financial statements.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

As required by Rule 13a-15(c) under the Exchange Act, the Partnership’s management, with the participation of the General Partner’s principal executive officers and principal financial officer, assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2013. In making this assessment, the Partnership’s management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control Integrated Framework (1992). Based on this assessment, the Partnership’s management, including the general partner’s principal executive officers and principal financial officer, concluded that, as of December 31, 2013, the Partnership’s internal control over financial reporting was effective based on those criteria.

Management excluded from its assessment of the effectiveness of the Partnership’s internal control over financial reporting the properties acquired in the Oklahoma Panhandle and Permian Basin acquisitions because they were acquired in purchase business combinations during July and December of 2013, respectively. The Oklahoma Panhandle acquisition total assets and total revenues represented approximately 20% and 17%, respectively, of the related consolidated statement amounts as of and the year ended December 31, 2013. The Permian Basin acquisition total assets represented approximately 7% of the related consolidated balance sheet amount as December 31, 2013.

PricewaterhouseCoopers LLP, the independent registered public accounting firm who audited the consolidated financial statements included in this Annual Report on Form 10-K, has also audited and issued a report on the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2013, which appears on page F-3.

/s/ Halbert S. Washburn  
Halbert S. Washburn  
Chief Executive Officer of BreitBurn GP, LLC

/s/ James G. Jackson  
James G. Jackson  
Chief Financial Officer of BreitBurn GP, LLC
In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, partners' equity and cash flows present fairly, in all material respects, the financial position of BreitBurn Energy Partners L.P. and its subsidiaries (the Partnership) at December 31, 2013 and 2012 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership’s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership’s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management’s Report on Internal Control Over Financial Reporting, management has excluded the properties acquired in the Oklahoma Panhandle and Permian Basin acquisitions during 2013 (together, the Acquired Properties) from its assessment of internal control over financial reporting as of December 31, 2013 because they were acquired by the Partnership in purchase business combinations in July and December 2013, respectively. We have also excluded the Acquired Properties from our audit of internal control over financial reporting. The Oklahoma Panhandle acquisition total assets and total revenues represent approximately 20% and 17%, respectively, of the related consolidated statement amounts as of and the year ended December 31, 2013. The Permian Basin acquisition total assets represent approximately 7% of the related consolidated balance sheet amount as of December 31, 2013.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 28, 2014
BreitBurn Energy Partners L.P. and Subsidiaries  
Consolidated Balance Sheets  

<table>
<thead>
<tr>
<th>Thousands</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current assets</td>
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<td></td>
</tr>
<tr>
<td>Cash</td>
<td>$2,458</td>
<td>$4,507</td>
</tr>
<tr>
<td>Accounts and other receivables, net (note 2)</td>
<td>96,862</td>
<td>67,862</td>
</tr>
<tr>
<td>Derivative instruments (note 4)</td>
<td>7,914</td>
<td>34,018</td>
</tr>
<tr>
<td>Related party receivables (note 4)</td>
<td>2,604</td>
<td>1,413</td>
</tr>
<tr>
<td>Inventory (note 6)</td>
<td>3,890</td>
<td>3,086</td>
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<tr>
<td>Prepaid expenses</td>
<td>3,334</td>
<td>2,779</td>
</tr>
<tr>
<td><strong>Total current assets</strong></td>
<td>117,062</td>
<td>113,665</td>
</tr>
<tr>
<td>Equity investments (note 7)</td>
<td>6,641</td>
<td>7,004</td>
</tr>
<tr>
<td><strong>Property, plant and equipment</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and gas properties (note 3)</td>
<td>4,818,639</td>
<td>3,363,946</td>
</tr>
<tr>
<td>Other properties</td>
<td>21,338</td>
<td>14,367</td>
</tr>
<tr>
<td><strong>Total property, plant and equipment</strong></td>
<td>4,839,977</td>
<td>3,378,313</td>
</tr>
<tr>
<td>Accumulated depletion and depreciation (note 8)</td>
<td>(924,601)</td>
<td>(666,420)</td>
</tr>
<tr>
<td><strong>Net property, plant and equipment</strong></td>
<td>3,915,376</td>
<td>2,711,893</td>
</tr>
<tr>
<td>Other long-term assets</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intangibles, net (note 9)</td>
<td>11,679</td>
<td>—</td>
</tr>
<tr>
<td>Derivative instruments (note 4)</td>
<td>71,319</td>
<td>55,210</td>
</tr>
<tr>
<td>Other long-term assets (note 9)</td>
<td>74,205</td>
<td>27,722</td>
</tr>
<tr>
<td><strong>Total other long-term assets</strong></td>
<td>157,203</td>
<td>82,932</td>
</tr>
<tr>
<td><strong>Total assets</strong></td>
<td>$4,196,282</td>
<td>$2,915,494</td>
</tr>
<tr>
<td><strong>LIABILITIES AND EQUITY</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current liabilities:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts payable</td>
<td>$69,809</td>
<td>$42,497</td>
</tr>
<tr>
<td>Derivative instruments (note 4)</td>
<td>24,876</td>
<td>5,625</td>
</tr>
<tr>
<td>Revenue and royalties payable</td>
<td>26,233</td>
<td>22,262</td>
</tr>
<tr>
<td>Wages and salaries payable</td>
<td>15,359</td>
<td>10,857</td>
</tr>
<tr>
<td>Accrued interest payable</td>
<td>19,690</td>
<td>13,002</td>
</tr>
<tr>
<td>Accrued liabilities</td>
<td>26,922</td>
<td>20,997</td>
</tr>
<tr>
<td><strong>Total current liabilities</strong></td>
<td>182,889</td>
<td>115,240</td>
</tr>
<tr>
<td>Credit facility (note 10)</td>
<td>733,000</td>
<td>345,000</td>
</tr>
<tr>
<td>Senior notes, net (note 10)</td>
<td>1,156,675</td>
<td>755,696</td>
</tr>
<tr>
<td>Deferred income taxes (note 12)</td>
<td>2,749</td>
<td>2,487</td>
</tr>
<tr>
<td>Asset retirement obligation (note 13)</td>
<td>123,769</td>
<td>98,480</td>
</tr>
<tr>
<td>Derivative instruments (note 4)</td>
<td>2,560</td>
<td>4,393</td>
</tr>
<tr>
<td>Other long-term liabilities</td>
<td>4,820</td>
<td>4,662</td>
</tr>
<tr>
<td><strong>Total liabilities</strong></td>
<td>2,206,462</td>
<td>1,325,958</td>
</tr>
<tr>
<td>Commitments and contingencies (note 14)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Equity</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Partners' equity (note 15)</td>
<td>1,989,820</td>
<td>1,589,536</td>
</tr>
<tr>
<td><strong>Total liabilities and equity</strong></td>
<td>$4,196,282</td>
<td>$2,915,494</td>
</tr>
</tbody>
</table>
The accompanying notes are an integral part of these consolidated financial statements.

F-4
BreitBurn Energy Partners L.P. and Subsidiaries  
Consolidated Statements of Operations

The accompanying notes are an integral part of these consolidated financial statements.

### Revenues and other income items:

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil, NGL and natural gas sales</td>
<td>$660,665</td>
<td>$413,867</td>
<td>$394,393</td>
</tr>
<tr>
<td>Gain (loss) on commodity derivative instruments, net (note 4)</td>
<td>$(29,182)</td>
<td>5,580</td>
<td>81,667</td>
</tr>
<tr>
<td>Other revenue, net (note 7)</td>
<td>3,175</td>
<td>3,548</td>
<td>4,310</td>
</tr>
<tr>
<td>Total revenues and other income items</td>
<td>634,658</td>
<td>422,995</td>
<td>480,370</td>
</tr>
</tbody>
</table>

### Operating costs and expenses:

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating costs</td>
<td>262,822</td>
<td>195,779</td>
<td>165,969</td>
</tr>
<tr>
<td>Depletion, depreciation and amortization</td>
<td>216,495</td>
<td>137,252</td>
<td>106,855</td>
</tr>
<tr>
<td>Impairments (note 8)</td>
<td>54,373</td>
<td>12,313</td>
<td>648</td>
</tr>
<tr>
<td>General and administrative expenses</td>
<td>58,707</td>
<td>55,465</td>
<td>53,200</td>
</tr>
<tr>
<td>(Gain) loss on sale of assets</td>
<td>(2,015)</td>
<td>486</td>
<td>(111)</td>
</tr>
<tr>
<td>Total operating costs and expenses</td>
<td>590,382</td>
<td>401,295</td>
<td>326,561</td>
</tr>
</tbody>
</table>

### Operating income

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating income</td>
<td>44,276</td>
<td>21,700</td>
<td>153,809</td>
</tr>
</tbody>
</table>

### Interest expense, net of capitalized interest (note 10)

- **2013**: $87,067
- **2012**: $61,206
- **2011**: $39,165

### Loss on interest rate swaps (note 4)

- **2013**: $—
- **2012**: $1,101
- **2011**: $2,777

### Other expense (income), net

- **2013**: $(25)
- **2012**: $48
- **2011**: $(19)

### Income (loss) before taxes

- **2013**: $(42,766)
- **2012**: $(40,655)
- **2011**: $111,886

### Income tax expense (note 12)

- **2013**: $905
- **2012**: $84
- **2011**: $1,188

### Net income (loss)

- **2013**: $(43,671)
- **2012**: $(40,739)
- **2011**: $110,698

Less: Net income attributable to noncontrolling interest (note 16)

- **2013**: $—
- **2012**: $(62)
- **2011**: $(201)

### Net income (loss) attributable to the partnership

- **2013**: $(43,671)
- **2012**: $(40,801)
- **2011**: $110,497

### Basic net income (loss) per unit (note 15)

- **2013**: $(0.43)
- **2012**: $(0.56)
- **2011**: $1.80

### Diluted net income (loss) per unit (note 15)

- **2013**: $(0.43)
- **2012**: $(0.56)
- **2011**: $1.79

The accompanying notes are an integral part of these consolidated financial statements.
## BreitBurn Energy Partners L.P. and Subsidiaries
### Consolidated Statements of Cash Flows

#### Year Ended December 31,

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cash flows from operating activities</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net income (loss)</td>
<td>$(43,671)</td>
<td>$(40,739)</td>
<td>$110,698</td>
</tr>
<tr>
<td>Adjustments to reconcile to cash flow from operating activities:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depletion, depreciation and amortization</td>
<td>216,495</td>
<td>137,252</td>
<td>106,855</td>
</tr>
<tr>
<td>Impairments</td>
<td>54,373</td>
<td>12,313</td>
<td>648</td>
</tr>
<tr>
<td>Unit-based compensation expense</td>
<td>19,955</td>
<td>22,266</td>
<td>22,043</td>
</tr>
<tr>
<td>(Gain) loss on derivative instruments</td>
<td>29,182</td>
<td>(4,479)</td>
<td>(78,890)</td>
</tr>
<tr>
<td>Derivative instrument settlements</td>
<td>8,083</td>
<td>84,615</td>
<td>17,455</td>
</tr>
<tr>
<td>Prepaid premiums on derivative instruments</td>
<td>—</td>
<td>(30,043)</td>
<td>—</td>
</tr>
<tr>
<td>Settlement payments on terminated derivative instruments</td>
<td>—</td>
<td>(2,479)</td>
<td>(36,779)</td>
</tr>
<tr>
<td>Income from equity affiliates, net</td>
<td>(55)</td>
<td>487</td>
<td>210</td>
</tr>
<tr>
<td>(Gain) loss on sale of assets</td>
<td>262</td>
<td>(316)</td>
<td>714</td>
</tr>
<tr>
<td>Other</td>
<td>5,163</td>
<td>4,472</td>
<td>(312)</td>
</tr>
<tr>
<td><strong>Net cash provided by operating activities</strong></td>
<td>257,166</td>
<td>191,782</td>
<td>128,543</td>
</tr>
</tbody>
</table>

#### Cash flows from investing activities (a)

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property acquisitions</td>
<td>(1,175,817)</td>
<td>(562,356)</td>
<td>(338,805)</td>
</tr>
<tr>
<td>Capital expenditures</td>
<td>(266,308)</td>
<td>(135,932)</td>
<td>(78,107)</td>
</tr>
<tr>
<td>Other</td>
<td>(26,661)</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Proceeds from sale of assets</td>
<td>2,981</td>
<td>1,129</td>
<td>2,339</td>
</tr>
<tr>
<td><strong>Net cash used in investing activities</strong></td>
<td>(1,465,805)</td>
<td>(697,159)</td>
<td>(414,573)</td>
</tr>
</tbody>
</table>

#### Cash flows from financing activities

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Issuance of common units, net</td>
<td>618,013</td>
<td>370,234</td>
<td>99,443</td>
</tr>
<tr>
<td>Distributions</td>
<td>(186,868)</td>
<td>(132,420)</td>
<td>(102,686)</td>
</tr>
<tr>
<td>Proceeds from issuance of long-term debt, net</td>
<td>2,276,000</td>
<td>1,502,885</td>
<td>661,500</td>
</tr>
<tr>
<td>Repayments of long-term debt</td>
<td>(1,487,000)</td>
<td>(1,223,000)</td>
<td>(369,500)</td>
</tr>
<tr>
<td>Change in bank overdraft</td>
<td>2,013</td>
<td>(3,176)</td>
<td>2,636</td>
</tr>
<tr>
<td>Debt issuance costs</td>
<td>(15,568)</td>
<td>(9,967)</td>
<td>(3,665)</td>
</tr>
<tr>
<td><strong>Net cash provided by financing activities</strong></td>
<td>1,206,590</td>
<td>504,556</td>
<td>287,728</td>
</tr>
</tbody>
</table>

#### Increase (decrease) in cash

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>(2,049)</td>
<td>(821)</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Cash end of period</strong></td>
<td>$2,458</td>
<td>$4,507</td>
<td>$5,328</td>
</tr>
</tbody>
</table>

(a) Non-cash investing activities in 2012 were $56 million, reflecting the issuance of approximately 3.01 million Common Units for the AEO Acquisition.

The accompanying notes are an integral part of these consolidated financial statements.
### BreitBurn Energy Partners L.P. and Subsidiaries
#### Consolidated Statements of Partners’ Equity

<table>
<thead>
<tr>
<th></th>
<th>Common Units</th>
<th>Partners’ Equity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Balance, December 31, 2010</strong></td>
<td>53,957</td>
<td>$1,208,803</td>
</tr>
<tr>
<td>Distributions on common units</td>
<td>—</td>
<td>(97,590)</td>
</tr>
<tr>
<td>Distributions paid on unissued units under incentive plans</td>
<td>—</td>
<td>(5,096)</td>
</tr>
<tr>
<td>Issuance of common units</td>
<td>4,945</td>
<td>99,443</td>
</tr>
<tr>
<td>Units issued under incentive plans</td>
<td>962</td>
<td>11,840</td>
</tr>
<tr>
<td>Unit-based compensation</td>
<td>—</td>
<td>(1,133)</td>
</tr>
<tr>
<td>Net income attributable to the partnership</td>
<td>—</td>
<td>110,497</td>
</tr>
<tr>
<td><strong>Balance, December 31, 2011</strong></td>
<td>59,864</td>
<td>$1,326,764</td>
</tr>
<tr>
<td>Distributions on common units</td>
<td>—</td>
<td>(127,748)</td>
</tr>
<tr>
<td>Distributions paid on unissued units under incentive plans</td>
<td>—</td>
<td>(4,672)</td>
</tr>
<tr>
<td>Sale of common units</td>
<td>20,699</td>
<td>370,177</td>
</tr>
<tr>
<td>Common units issued in acquisition</td>
<td>3,014</td>
<td>55,691</td>
</tr>
<tr>
<td>Units issued under incentive plans</td>
<td>1,091</td>
<td>24,381</td>
</tr>
<tr>
<td>Unit-based compensation</td>
<td>—</td>
<td>(14,314)</td>
</tr>
<tr>
<td>Net loss attributable to the partnership</td>
<td>—</td>
<td>(40,801)</td>
</tr>
<tr>
<td>Other</td>
<td>—</td>
<td>58</td>
</tr>
<tr>
<td><strong>Balance, December 31, 2012</strong></td>
<td>84,668</td>
<td>$1,589,536</td>
</tr>
<tr>
<td>Distributions on common units</td>
<td>—</td>
<td>(183,594)</td>
</tr>
<tr>
<td>Distributions paid on unissued units under incentive plans</td>
<td>—</td>
<td>(3,274)</td>
</tr>
<tr>
<td>Sales of common units</td>
<td>33,925</td>
<td>617,752</td>
</tr>
<tr>
<td>Units issued under incentive plans</td>
<td>577</td>
<td>12,421</td>
</tr>
<tr>
<td>Unit-based compensation</td>
<td>—</td>
<td>650</td>
</tr>
<tr>
<td>Net loss attributable to the partnership</td>
<td>—</td>
<td>(43,671)</td>
</tr>
<tr>
<td><strong>Balance, December 31, 2013</strong></td>
<td>119,170</td>
<td>$1,989,820</td>
</tr>
</tbody>
</table>

*The accompanying notes are an integral part of these consolidated financial statements.*
Notes to Consolidated Financial Statements

Note 1. Organization

We are a Delaware limited partnership formed on March 23, 2006. Our initial public offering was in October 2006. Pacific Coast Energy Company LP (“PCEC”), formerly BreitBurn Energy Company L.P., was our Predecessor.

Our general partner is BreitBurn GP, LLC, a Delaware limited liability company (the “General Partner”), also formed on March 23, 2006. The board of directors of our General Partner has sole responsibility for conducting our business and managing our operations. We conduct our operations through a wholly-owned subsidiary, BreitBurn Operating L.P., (“BOLP”) and BOLP’s general partner BreitBurn Operating GP, LLC (“BOGP”). We own all of the ownership interests in BOLP and BOGP.

Our wholly owned subsidiary, BreitBurn Management, manages our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. See Note 5 for information regarding our relationship with BreitBurn Management. Our wholly-owned subsidiary, BreitBurn Finance Corporation, was incorporated on June 1, 2009 under the laws of the State of Delaware. BreitBurn Finance Corporation has no assets or liabilities, and its activities are limited to co-issuing debt securities and engaging in other activities incidental thereto. Our wholly-owned subsidiary, BreitBurn Collingwood Utica LLC (“Utica”) holds certain non-producing oil and gas zones in the Collingwood-Utica shale play in Michigan and is classified as an unrestricted subsidiary under our credit facility.

We own 100% of the General Partner, BreitBurn Management, BOLP, BreitBurn Finance Corporation and Utica.

As of December 31, 2013, public unitholders owned 99.42% of our Common Units and the Strand Energy Company owned 0.7 million Common Units, representing a 0.58% limited partner interest.

2. Summary of Significant Accounting Policies

Principles of consolidation and basis of presentation

The consolidated financial statements include our accounts and the accounts of our wholly owned subsidiaries. Investments in affiliated companies with a 20% or greater ownership interest, and in which we have significant influence but do not have control, are accounted for on an equity basis. Investments in affiliated companies with less than a 20% ownership interest, and in which we do not have control, are accounted for on the cost basis. Investments in which we own greater than a 50% interest and in which we have control are consolidated. Investments in which we own less than a 50% interest but are deemed to have control, or where we have a variable interest in an entity in which we will absorb a majority of the entity’s expected losses or receive a majority of the entity’s expected residual returns or both, however, are consolidated. The effects of all intercompany transactions have been eliminated.

Certain reclassifications have been made to our 2012 and 2011 consolidated financial statements in order to conform them to the 2013 presentation. These reclassifications were not material to the financial statements.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The financial statements are based on a number of significant estimates including acquisition purchase price allocations, fair value of derivative instruments, unit-based compensation and oil and gas reserve quantities, which are the basis for the calculation of depletion, depreciation and amortization (“DD&A”), asset retirement obligations and impairment of oil and gas properties.
Business segment information

We report our operations in one segment because our oil and gas operating areas have similar economic characteristics. We acquire, exploit, develop and produce oil and natural gas in the United States. Corporate management administers all properties as a whole rather than as discrete operating segments. Operational data is tracked by area; however, financial performance is measured as a single enterprise and not on an area-by-area basis. Allocation of capital resources is employed on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas.

Revenue recognition

We recognize revenue when it is realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred, (iii) the seller's price to the buyer is fixed or determinable and (iv) collectability is reasonably assured.

Revenues from properties in which we have an interest with other partners are recognized on the basis of our working interest (“entitlement” method of accounting). We generally market most of our natural gas production from our operated properties and pay our partners for their working interest shares of natural gas production sold. As a result, we have no material natural gas producer imbalance positions.

Accounts receivable

Our accounts receivable are primarily from purchasers of oil and natural gas and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2013 and 2012, we had an allowance for doubtful accounts receivable of $0.6 million and $0.6 million, respectively.

Inventory

Our inventory consists of oil held in storage tanks related to our Florida operations pending shipment by barge to the point of sale. Oil inventories are carried at the lower of cost to produce or market price. We match production expenses with oil sales. Production expenses associated with unsold oil inventory are recorded as inventory.

Investments in equity affiliates

Income from equity affiliates is included as a component of operating income, as the operations of these affiliates are associated with the processing and transportation of our natural gas production.

Property, plant and equipment

Oil and gas properties

We follow the successful efforts method of accounting. Lease acquisition and development costs (tangible and intangible) incurred relating to proved oil and gas properties are capitalized. Delay and surface rentals are charged to expense as incurred. Dry hole costs incurred on exploratory wells are expensed. Dry hole costs associated with developing proved fields are capitalized. Geological and geophysical costs related to exploratory operations are expensed as incurred.

The Partnership carries out tertiary recovery methods on certain of its oil and gas properties in Oklahoma in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Acquisition costs of tertiary injectants, such as purchased CO₂, for enhanced oil recovery (“EOR”) activities that are used prior to the recognition of proved tertiary recovery reserves are expensed as incurred. After a project has been determined to be technically feasible and economically viable, all acquisition costs of tertiary injectants are capitalized as development.
costs and depleted, as they are incurred solely for obtaining access to reserves not otherwise recoverable and have future economic benefits over the life of the project. As CO$_2$ is recovered together with oil and gas production, it is extracted and re-injected, and all the associated CO$_2$ recycling costs are expensed as incurred. Likewise, other costs incurred to maintain reservoir pressure are also expensed.

Upon sale or retirement of proved properties, the cost thereof and the DD&A are removed from the accounts and any gain or loss is recognized in the statement of operations. Maintenance and repairs are charged to operating expenses. DD&A of proved oil and gas properties, including the estimated cost of future abandonment and restoration of well sites and associated facilities, is generally computed on a field-by-field basis where applicable and recognized using the units of production method net of any anticipated proceeds from equipment salvage and sale of surface rights. Other gathering and processing facilities are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, generally over 20 years.

We capitalize interest costs to oil and gas properties on expenditures made in connection with major projects and the drilling and completion of new oil and natural gas wells. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the units of production method. During 2013, 2012 and 2011, interest of $0.1 million, $0.1 million and $0.1 million, respectively, was capitalized and included in our capital expenditures.

**Non-oil and gas assets**

Buildings and non-oil and gas assets are recorded at cost and depreciated using the straight-line method over their estimated useful lives, which range from three to ten years.

**Oil and natural gas reserve quantities**

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion are made concurrently with changes to reserve estimates. We disclose reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with the Securities and Exchange Commission (the “SEC”) guidelines. The independent engineering firms adhere to the SEC definitions when preparing their reserve reports.

**Asset retirement obligations**

We have significant obligations to plug and abandon oil and natural gas wells and related equipment at the end of oil and natural gas production operations. The fair value of a liability for an asset retirement obligation (“ARO”) is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Over time, changes in the present value of the liability are accreted and recorded as part of DD&A on the consolidated statements of operations. The capitalized asset costs are depreciated over the useful lives of the corresponding asset. Recognized liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as: (1) expected economic recoveries of oil and natural gas, (2) time to abandonment, (3) future inflation rates and (4) the risk free rate of interest adjusted for our credit costs. Future revisions to ARO estimates will impact the present value of existing ARO liabilities and corresponding adjustments will be made to the capitalized asset retirement costs balance.

**Impairment of assets**

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value. A long-lived asset is tested for impairment periodically and when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. For purposes of performing an impairment test, the undiscounted future cash flows are
based on total proved and risk-adjusted probable and possible reserves, and are forecast using five-year NYMEX forward strip prices at the end of the period and escalated along with expenses and capital starting year six and thereafter at 2.5% per year. For impairment charges, the associated property’s expected future net cash flows are discounted using a weighted average cost of capital which approximated 10% at December 31, 2013. Reserves are calculated based upon reports from third party engineers adjusted for acquisitions or other changes occurring during the year as determined to be appropriate in the good faith judgment of management. Unproved properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred.

We assess our long-lived assets for impairment generally on a field-by-field basis where applicable. See Note 8 for a discussion of our impairments.

**Debt issuance costs**

The costs incurred to obtain financing have been capitalized. Debt issuance costs are amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the effective interest method of amortization.

**Equity-based compensation**

BreitBurn Management has various forms of equity-based compensation outstanding under employee compensation plans that are described more fully in Note 17. Awards classified as equity are valued on the grant date and are recognized as compensation expense over the vesting period, which is part of the general and administrative ("G&A") expenses line on the Consolidated Statements of Operations. We recognize equity-based compensation costs on a straight line basis over the annual vesting periods.

**Fair market value of financial instruments**

The carrying amount of our cash, accounts receivable, accounts payable, related party receivables and payables and accrued expenses approximate their respective fair value due to the relatively short term of the related instruments. The carrying amount of long-term debt under our credit facility approximates fair value; however, changes in the credit markets may impact our ability to enter into future credit facilities at similar terms. See Note 10 for the fair value of our Senior Notes under long-term debt.

**Accounting for business combinations**

We account for all business combinations using the acquisition method. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, equity or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if material, is recognized as a gain at the time of acquisition. Similarly, the deficit of the fair value of assets acquired and liabilities assumed under the cost of an acquired entity, if material, is recognized as goodwill at the time of acquisition. All purchase price allocations are finalized within one year from the acquisition date.

**Concentration of credit risk**

We maintain our cash accounts primarily with a single bank and invest cash in money market accounts, which we believe to have minimal risk. At times, such balances may be in excess of the Federal Insurance Corporation insurance limit. As operator of jointly owned oil and gas properties, we sell oil and gas production to U.S. oil and gas purchasers and pay vendors on behalf of joint owners for oil and gas services. We periodically monitor our major purchasers’ credit ratings. We enter into commodity and interest rate derivative instruments. Our derivative counterparties are all lenders under our credit facility, and we periodically monitor their credit ratings.
Derivatives

Financial Accounting Standards Board (“FASB”) Accounting Standards establish accounting and reporting requirements for derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities. These standards require recognition of all derivative instruments as assets or liabilities on our balance sheet and measurement of those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge and if so, the type of hedge. We currently do not designate any of our derivatives as hedges for financial accounting purposes. Gains and losses on derivative instruments not designated as hedges are currently included in earnings. The resulting cash flows are reported as cash from operating activities.

Fair value measurement is based upon a hypothetical transaction to sell an asset or transfer a liability at the measurement date. The objective of fair value measurement is to determine the price that would be received in selling the asset or transferring the liability in an orderly transaction between market participants at the measurement date. If we have a principal market for the asset or liability, the fair value measurement shall represent the price in that market, otherwise the price will be determined based on the most advantageous market.

Income taxes

Our subsidiaries are mostly partnerships or limited liability companies treated as partnerships for federal tax purposes with essentially all taxable income or loss being passed through to the members. As such, no federal income tax for these entities has been provided.

We have three wholly-owned subsidiaries that are subject to corporate income taxes. Deferred income taxes are recorded under the asset and liability method. Where material, deferred income tax assets and liabilities are computed for differences between the financial statement and income tax bases of assets and liabilities that will result in taxable or deductible amounts in the future. Such deferred income tax asset and liability computations are based on enacted tax laws and rates applicable to periods in which the differences are expected to affect taxable income. Income tax expense is the tax payable or refundable for the period plus or minus the change during the period in deferred income tax assets and liabilities.

FASB Accounting Standards clarify the accounting for uncertainty in income taxes recognized in a company’s financial statements. A company can only recognize an uncertain tax position in the financial statements if the position is more-likely-than-not to be upheld on audit based only on the technical merits of the tax position. This accounting standard also provides guidance on thresholds, measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition that is intended to provide better financial-statement comparability among different companies.

We performed analysis as of December 31, 2013 and 2012 and concluded that there were no uncertain tax positions requiring recognition in our financial statements.

Net Income or loss per unit

FASB Accounting Standards require use of the “two-class” method of computing earnings per unit for all periods presented. The “two-class” method is an earnings allocation formula that determines earnings per unit for each class of Common Unit and participating security as if all earnings for the period had been distributed. Unvested restricted unit awards that earn non-forfeitable dividend rights qualify as participating securities and, accordingly, are included in the basic computation. Our unvested restricted phantom units (“RPUs”) and convertible phantom units (“CPUs”) participate in dividends on an equal basis with Common Units; therefore, there is no difference in undistributed earnings allocated to each participating security. Accordingly, our calculation is prepared on a combined basis and is presented as net income (loss) per Common Unit. See Note 15 for our earnings per Common Unit calculation.
Environmental expenditures

We review, on an annual basis, our estimates of the cleanup costs of various sites. When it is probable that obligations have been incurred and where a reasonable estimate of the cost of compliance or remediation can be determined, the applicable amount is accrued. At December 31, 2013, we had a $2.2 million undiscounted environmental liability accrued that included cost estimates related to the maintenance of groundwater monitoring wells associated with certain former well sites in Michigan that are no longer producing. At December 31, 2012, we had a $1.9 million undiscounted environmental liability accrued.

Accounting Standards

There were no new accounting standards issued but not yet effective that are expected to have a material impact on our financial position, results of operations or cash flows.

3. Acquisitions

We account for all business combinations using the acquisition method of accounting. The initial accounting applied to our acquisitions at the time of the purchase may not be complete and adjustment to provisional accounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition date prior to concluding on the final purchase price of an acquisition.

Our purchase price allocations are based on discounted cash flows, quoted market prices and estimates made by management, and the most significant assumptions are those related to the estimated fair values assigned to oil and natural gas properties with proved and unproved reserves. To estimate the fair values of acquired properties, estimates of oil and natural gas reserves are prepared by management in consultation with independent engineers. We apply estimated future prices to the estimated reserve quantities acquired, and estimate future operating and development costs to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital. We also periodically employ third-party valuation firms to assist in the valuation of complex facilities, including pipelines, gathering lines and processing facilities.

We conducted assessments of net assets acquired and recognized certain amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values. Transaction and integration costs associated with our acquisitions are expensed as incurred.

The fair value measurements of oil and natural gas properties, other assets and ARO are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties, other assets and ARO were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and a market-based weighted average cost of capital rate. ARO assumptions include inputs such as expected economic recoveries of oil and natural gas, time to abandonment. These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

2013 Acquisitions

Oklahoma Panhandle Acquisitions

On July 15, 2013, we completed the acquisition of certain oil and natural gas and midstream assets located in Oklahoma, New Mexico and Texas, certain carbon dioxide (“CO₂”) supply contracts, certain oil swaps and interests in certain entities from Whiting Oil and Gas Corporation (“Whiting”) for approximately $845 million in cash (the “Whiting
Acquisition”), including post-closing adjustments. We used borrowings under our credit facility to fund this acquisition. The purchase price for this acquisition was allocated to the assets acquired and liabilities assumed as follows:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas properties - proved</td>
</tr>
<tr>
<td>Oil and gas properties - unproved</td>
</tr>
<tr>
<td>Pipeline and processing facilities</td>
</tr>
<tr>
<td>Derivative assets - current</td>
</tr>
<tr>
<td>Intangibles</td>
</tr>
<tr>
<td>Derivative assets - long-term</td>
</tr>
<tr>
<td>Other long-term assets</td>
</tr>
<tr>
<td>Derivative liabilities - current</td>
</tr>
<tr>
<td>Accrued liabilities</td>
</tr>
<tr>
<td>Asset retirement obligation</td>
</tr>
<tr>
<td>$</td>
</tr>
</tbody>
</table>

Whiting novated to us derivative contracts, with a counterparty that is a participant in our current credit facility, consisting of NYMEX West Texas Intermediate (“WTI”) fixed price oil swaps covering a total of approximately 5.4 million barrels of future production in 2013 and extending through 2016 at a weighted average hedge price of $95.44 per Bbl, which were valued as a net asset of $9.9 million at the acquisition date. The purchase price allocation also included finite-lived intangibles valued at $14.7 million relating to two CO₂ purchase contracts that we received in the acquisition. An intangible asset was established to value the portion of the CO2 contracts that were above market at closing in the purchase price allocation. We amortize the CO₂ contracts based on the amount of CO₂ purchases made in each period over the contracts’ respective lives. We were also novated a $10.9 million long-term advance balances relating to future CO₂ supply contract arrangements. The $10.9 million long-term advance was reflected on the initial purchase price of $835.4 million, included in our third quarter 2013 10-Q, as $1.0 million. See Note 9 for further details on the intangibles and other long-term assets acquired.

We also completed the acquisition of additional interests in certain of the acquired assets in the Oklahoma Panhandle from other sellers than Whiting for an additional $30 million in July 2013 (together with the Whiting Acquisition, the “Oklahoma Panhandle Acquisitions”). The additional interests were allocated $17.8 million to oil and gas properties and $12.4 million to pipeline facilities.

Acquisition-related costs for the Oklahoma Panhandle Acquisitions were $3.2 million for the year ended December 31, 2013 and are reflected in G&A expenses on the consolidated statements of operations. For the year ended December 31, 2013, we recorded $104.9 million in sales revenue and $29.9 million in lease operating expenses, including production and property taxes, from our Oklahoma Panhandle Acquisitions.

**Permian Basin Acquisitions**

On December 30, 2013, we completed acquisitions of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P. for approximately $282 million in cash (the “CrownRock III Acquisition”). We also completed the acquisition of additional interests in certain of the acquired assets in the Permian Basin from other sellers for an additional $20 million in December 2013 (together with the CrownRock III Acquisition, the “2013 Permian Basin Acquisitions”). The preliminary purchase price for 2013 Permian Acquisitions was allocated to the assets acquired and liabilities assumed as follows:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas properties - proved</td>
</tr>
<tr>
<td>Oil and gas properties - unproved</td>
</tr>
<tr>
<td>Asset retirement obligation</td>
</tr>
<tr>
<td>$</td>
</tr>
</tbody>
</table>
Acquisition-related costs for the 2013 Permian Basin Acquisitions were $0.1 million for the year ended December 31, 2013 and are reflected in G&A expenses on the consolidated statements of operations. For the year ended December 31, 2013, we recorded two days of sales revenue less lease operating expenses and production and property taxes, which was a net revenue of $0.2 million from our 2013 Permian Basin Acquisitions.

2012 Acquisitions

NiMin Acquisition

In June 2012, we completed the acquisition of oil properties located in Park County in the Bighorn Basin of Wyoming from Legacy Energy, Inc., a wholly-owned subsidiary of NiMin Energy Corp. (the “NiMin Acquisition”). The final purchase price for this acquisition was approximately $95 million in cash, which was primarily allocated to oil and natural gas properties (including $36.2 million in unproved properties) and included $1.7 million of ARO. Acquisition-related costs for the NiMin Acquisition were $0.4 million and are reflected in G&A expenses on the consolidated statements of operations. Revenues and expenses from the NiMin properties are reflected in our consolidated statements of operations beginning June 28, 2012. For the year ended December 31, 2013 and 2012, we recorded $15.2 million and $6.6 million, respectively, in sales revenue and $6.1 million and $3.2 million, respectively, in lease operating expenses, including production and property taxes, from our NiMin properties.

Permian Basin Acquisitions

On July 2, 2012, we completed acquisitions of oil and natural gas properties located in the Permian Basin in Texas from Element Petroleum, LP and CrownRock, L.P. for approximately $148 million and $70 million, respectively. On December 28, 2012, we completed the acquisition of oil and natural gas properties located in the Permian Basin in Texas from CrownRock, L.P., Lynden USA Inc. and Piedra Energy I, LLC for approximately $164 million, $25 million and $10 million, respectively. The final purchase price for each of the 2012 acquisitions in the Permian Basin was primarily allocated to oil and natural gas properties, including $52.5 million of unproved oil and gas properties, with $44.3 million related to the Element Petroleum, LP acquisition and $8.2 million related to the first CrownRock, L.P., acquisition. Acquisition-related costs for the July 2012 Permian Basin acquisitions were $1.0 million and were recorded in G&A expenses on the consolidated statements of operations. Acquisition-related costs for the December 2012 Permian Basin acquisitions were $0.5 million and were recorded in G&A expenses on the consolidated statements of operations. For the year ended December 31, 2013 and December 31, 2012, we recorded $88.3 million and $19.1 million, respectively, in sales revenue and $19.0 million and $3.8 million, respectively, in lease operating expenses, including production and property taxes, from our Permian Basin properties.

AEO Acquisition

On November 30, 2012, we completed the acquisition of principally oil properties from American Energy Operations, Inc. (“AEO”) located in the Belridge Field in Kern County, California (the “AEO Acquisition”), with an effective date of November 1, 2012, for approximately $38 million in cash and 3.01 million Common Units. Of the final purchase price of $38 million in cash and $56 million in Common Units, $97.8 million was allocated to proved oil properties, and 4.0 million was allocated to ARO as follows:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas properties - proved</td>
<td>$ 97,814</td>
</tr>
<tr>
<td>Asset retirement obligation</td>
<td>(4,014)</td>
</tr>
<tr>
<td>Net assets acquired</td>
<td>$ 93,800</td>
</tr>
</tbody>
</table>

Acquisition-related costs for the AEO Acquisition were $0.4 million and were recorded in G&A expenses on the consolidated statements of operations beginning December 1, 2012. For the year ended December 31, 2013 and December 31, 2012, we recorded $36.8 million and $2.6 million in sales revenue, respectively, and $7.2 million and $0.6 million in lease operating expenses, including production and property taxes, respectively, from the properties acquired in the AEO Acquisition.
2011 Acquisitions

On July 28, 2011, we completed the acquisition of oil properties in the Powder River Basin in eastern Wyoming with an effective date of July 1, 2011 (the “Greasewood Acquisition”). We used borrowings under our credit facility to fund the Greasewood Acquisition. The final purchase price for the acquisition was approximately $57 million in cash, which was primarily allocated to proved oil properties. Acquisition-related costs for the Greasewood Acquisition were $0.1 million and were reflected in G&A expenses on the consolidated statements of operations. In 2011, we recorded $7.4 million in sales revenue and $1.9 million in lease operating expenses, including production and property taxes, from the properties acquired in the Greasewood Acquisition.

On October 6, 2011, we completed the acquisition of oil and gas properties from Cabot Oil & Gas Corporation located primarily in the Evanston and Green River Basins in southwestern Wyoming (the “Cabot Acquisition”), with an effective date of September 1, 2011. We used borrowings under our credit facility to fund the Cabot Acquisition. The assets acquired also include limited acreage and non-operated oil and gas interests in Colorado and Utah. The final purchase price of $281 million was allocated to the assets acquired and liabilities assumed as follows:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accounts receivable</td>
<td>767</td>
</tr>
<tr>
<td>Oil and gas properties</td>
<td>294,500</td>
</tr>
<tr>
<td>Accounts payable</td>
<td>(197 )</td>
</tr>
<tr>
<td>Revenue and royalties payable</td>
<td>(798 )</td>
</tr>
<tr>
<td>Asset retirement obligation</td>
<td>(10,845 )</td>
</tr>
<tr>
<td>Other long-term liabilities</td>
<td>(2,820 )</td>
</tr>
<tr>
<td>Total</td>
<td>280,607</td>
</tr>
</tbody>
</table>

Acquisition-related costs for the Cabot Acquisition were $0.6 million and were recorded in G&A expenses on the consolidated statements of operations. In 2011, we recorded $9.1 million in sales revenue and $3.9 million in lease operating expenses, including production and property taxes, from the properties acquired in the Cabot Acquisition.

**Pro Forma (unaudited)**

The following unaudited pro forma financial information presents a summary of our combined statements of operations for the years ended December 31, 2013, 2012, and 2011 assuming: (i) the Whiting Acquisition and additional acquired assets in the Oklahoma Panhandle acquisitions and the 2013 Permian Basin Acquisitions were completed on January 1, 2012, and (ii) the AEO Acquisition, the NiMin Acquisition, the 2012 acquisitions from Element Petroleum, LP, CrownRock, L.P., Piedra Energy I, LLC and Lynden USA Inc. and the Cabot Acquisition were completed on January 1, 2011. The pro forma results reflect the results of combining our statements of operations with the results of operations from all of our 2012 and 2013 acquisitions, adjusted for (1) the assumption of ARO and accretion expense for the properties acquired, (2) depletion and depreciation expense applied to the adjusted purchase price of the properties acquired, and (3) interest expense on additional borrowings necessary to finance the acquisitions, including the amortization of debt issuance costs. The pro forma financial information is not necessarily indicative of the results of operations if these acquisitions had been effective January 1, 2012 or 2011.

<table>
<thead>
<tr>
<th>Thousands of dollars, except per unit amounts</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenues</td>
<td>$ 828,483</td>
<td>$ 781,342</td>
<td>$ 615,310</td>
</tr>
<tr>
<td>Net income (loss) attributable to the partnership</td>
<td>27,518</td>
<td>85,594</td>
<td>146,992</td>
</tr>
</tbody>
</table>

Net income (loss) per common unit:

<table>
<thead>
<tr>
<th></th>
<th>Basic</th>
<th></th>
<th>Diluted</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$</td>
<td>$ 0.23</td>
<td>$ 0.71</td>
</tr>
<tr>
<td></td>
<td>$</td>
<td>$ 0.23</td>
<td>$ 1.71</td>
</tr>
</tbody>
</table>

F-16
4. Financial Instruments and Fair Value Measurements

Our risk management programs are intended to reduce our exposure to commodity prices and interest rates and to assist with stabilizing cash flows.

Commodity Activities

Due to the historical volatility of oil and natural gas prices, we have entered into various derivative instruments to manage exposure to volatility in the market price of oil and natural gas to achieve more predictable cash flows. We use swaps, collars and options for managing risk relating to commodity prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in us having lower revenues than we would otherwise have if we had not utilized these instruments in times of higher oil and natural gas prices, management believes that the resulting reduced volatility of prices and cash flow is beneficial. While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow and distributions, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected.

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and natural gas prices realized in our operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for cash flow hedges under FASB Accounting Standards. Accordingly, we do not attempt to account for our derivative instruments as cash flow hedges for financial accounting purposes and instead recognize changes in the fair value immediately in earnings.

We had the following oil contracts in place at December 31, 2013:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Price Swaps - NYMEX WTI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Volume (Bbl/d)</strong></td>
<td>13,814</td>
<td>12,689</td>
<td>9,211</td>
<td>7,971</td>
<td>493</td>
</tr>
<tr>
<td><strong>Average Price ($/Bbl)</strong></td>
<td>$92.30</td>
<td>$93.01</td>
<td>$86.73</td>
<td>$84.23</td>
<td>$82.20</td>
</tr>
<tr>
<td>Fixed Price Swaps - ICE Brent</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Volume (Bbl/d)</strong></td>
<td>4,800</td>
<td>3,300</td>
<td>4,300</td>
<td>298</td>
<td>—</td>
</tr>
<tr>
<td><strong>Average Price ($/Bbl)</strong></td>
<td>$98.88</td>
<td>$97.73</td>
<td>$95.17</td>
<td>$97.50</td>
<td>—</td>
</tr>
<tr>
<td>Collars - NYMEX WTI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Volume (Bbl/d)</strong></td>
<td>1,000</td>
<td>1,000</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Average Floor Price ($/Bbl)</strong></td>
<td>$90.00</td>
<td>$90.00</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Average Ceiling Price ($/Bbl)</strong></td>
<td>$112.00</td>
<td>$113.50</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Collars - ICE Brent</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Volume (Bbl/d)</strong></td>
<td>—</td>
<td>500</td>
<td>500</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Average Floor Price ($/Bbl)</strong></td>
<td>—</td>
<td>$90.00</td>
<td>$90.00</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Average Ceiling Price ($/Bbl)</strong></td>
<td>—</td>
<td>$109.50</td>
<td>$101.25</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Puts - NYMEX WTI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Volume (Bbl/d)</strong></td>
<td>500</td>
<td>500</td>
<td>1,000</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td><strong>Average Price ($/Bbl)</strong></td>
<td>$90.00</td>
<td>$90.00</td>
<td>$90.00</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Total:</td>
<td>20,114</td>
<td>17,989</td>
<td>15,011</td>
<td>8,269</td>
<td>493</td>
</tr>
<tr>
<td><strong>Average Price ($/Bbl)</strong></td>
<td>$93.70</td>
<td>$93.54</td>
<td>$89.48</td>
<td>$84.71</td>
<td>$82.20</td>
</tr>
</tbody>
</table>
We had the following natural gas contracts in place at December 31, 2013:

<table>
<thead>
<tr>
<th>Gas Positions:</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Price Swaps - MichCon City-Gate</td>
<td>2014</td>
</tr>
<tr>
<td>Volume (MMBtu/d)</td>
<td>7,500</td>
</tr>
<tr>
<td>Average Price ($/MMBtu)</td>
<td>$ 6.00</td>
</tr>
<tr>
<td>Volume (MMBtu/d)</td>
<td>41,600</td>
</tr>
<tr>
<td>Average Price ($/MMBtu)</td>
<td>$ 4.75</td>
</tr>
<tr>
<td>Volume (MMBtu/d)</td>
<td>6,000</td>
</tr>
<tr>
<td>Average Price ($/MMBtu)</td>
<td>$ 5.00</td>
</tr>
<tr>
<td>Volume (MMBtu/d)</td>
<td>55,100</td>
</tr>
<tr>
<td>Average Price ($/MMBtu)</td>
<td>$ 4.95</td>
</tr>
</tbody>
</table>

During the year ended December 31, 2013, we did not enter into any derivative instruments that required prepaid premiums. During the year ended December 31, 2012, we paid $23.0 million and $7.0 million in premiums on oil and natural gas derivative instruments, respectively, that related to future periods.

During the year ended December 31, 2013 and 2012, $4.9 million and $0.9 million, respectively, of premiums paid in 2012 related to oil and gas derivatives settled. As of December 31, 2013, premiums paid in 2012 related to oil and natural gas derivatives to be settled in 2014 and beyond were as follows:

<table>
<thead>
<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>$ 4,479</td>
<td>$ 4,683</td>
<td>$ 7,438</td>
<td>$ 734</td>
<td>—</td>
</tr>
<tr>
<td>Natural gas</td>
<td>$ 4,015</td>
<td>$ 1,989</td>
<td>$ 952</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

Interest Rate Activities

We are subject to interest rate risk associated with loans under our credit facility that bear interest based on floating rates. As of December 31, 2013 and 2012, we had no interest rate swaps in place. In order to mitigate our interest rate exposure, we had the following interest rate swaps, indexed to 1-month LIBOR, in place at December 31, 2011, to fix a portion of floating LIBOR-base debt under our credit facility. As of December 31, 2011, we had an interest rate swap covering January 1, 2012 to December 20, 2012 for $100 million at a fixed rate of 1.1550% and an interest rate swap covering January 20, 2012 to January 20, 2014 for $100 million at 2.4800%. The first contract expired in December 2012. In the fourth quarter of 2012, we terminated the second contract and realized a loss of $2.5 million. We did not designate these interest rate derivatives as hedges for financial accounting purposes.

Fair Value of Financial Instruments

FASB Accounting Standards require disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedge items are accounted for, and how derivative instruments and related hedged
items affect an entity’s financial position, financial performance, and cash flows. The required disclosures are detailed below.

Fair value of derivative instruments not designated as hedging instruments:

<table>
<thead>
<tr>
<th>Balance sheet location, thousands of dollars</th>
<th>Oil Commodity Derivatives</th>
<th>Natural Gas Commodity Derivatives</th>
<th>Commodity Derivatives Netting (a)</th>
<th>Total Financial Instruments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>As of December 31, 2013</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assets</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current assets - derivative instruments</td>
<td>$4,373</td>
<td>$15,419</td>
<td>$(11,878)</td>
<td>$7,914</td>
</tr>
<tr>
<td>Other long-term assets - derivative instruments</td>
<td>59,412</td>
<td>23,750</td>
<td>(11,843)</td>
<td>71,319</td>
</tr>
<tr>
<td>Total assets</td>
<td>63,785</td>
<td>39,169</td>
<td>(23,721)</td>
<td>79,233</td>
</tr>
<tr>
<td>Liabilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current liabilities - derivative instruments</td>
<td>(35,634)</td>
<td>(1,120)</td>
<td>11,878</td>
<td>(24,876)</td>
</tr>
<tr>
<td>Long-term liabilities - derivative instruments</td>
<td>(13,620)</td>
<td>(783)</td>
<td>11,843</td>
<td>(2,560)</td>
</tr>
<tr>
<td>Total liabilities</td>
<td>(49,254)</td>
<td>(1,903)</td>
<td>23,721</td>
<td>(27,436)</td>
</tr>
<tr>
<td>Net assets (liabilities)</td>
<td>$14,531</td>
<td>$37,266</td>
<td>$—</td>
<td>$51,797</td>
</tr>
<tr>
<td><strong>As of December 31, 2012</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assets</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current assets - derivative instruments</td>
<td>$4,270</td>
<td>$46,724</td>
<td>$(16,976)</td>
<td>$34,018</td>
</tr>
<tr>
<td>Other long-term assets - derivative instruments</td>
<td>38,919</td>
<td>33,443</td>
<td>(17,152)</td>
<td>55,210</td>
</tr>
<tr>
<td>Total assets</td>
<td>43,189</td>
<td>80,167</td>
<td>(34,128)</td>
<td>89,228</td>
</tr>
<tr>
<td>Liabilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current liabilities - derivative instruments</td>
<td>(21,665)</td>
<td>(936)</td>
<td>16,976</td>
<td>(5,625)</td>
</tr>
<tr>
<td>Long-term liabilities - derivative instruments</td>
<td>(18,769)</td>
<td>(2,776)</td>
<td>17,152</td>
<td>(4,393)</td>
</tr>
<tr>
<td>Total liabilities</td>
<td>(40,434)</td>
<td>(3,712)</td>
<td>34,128</td>
<td>(10,018)</td>
</tr>
<tr>
<td>Net assets (liabilities)</td>
<td>$2,755</td>
<td>$76,455</td>
<td>$—</td>
<td>$79,210</td>
</tr>
</tbody>
</table>

(a) Represents counterparty netting under derivative netting agreements - these contracts are reflected net on the balance sheet.
Gains and losses on derivative instruments not designated as hedging instruments:

(a) Included in gain (loss) on commodity derivative instruments, net on the consolidated statements of operations.

(b) Included in loss on interest rate swaps on the consolidated statements of operations included in gain (loss) on commodity derivative instruments, net on the consolidated statements of operations.

In the fourth quarter of 2011, in order to improve the effectiveness of our hedge portfolio, we terminated certain oil fixed price swaps at NYMEX WTI prices for a total termination cost of $36.8 million, included in 2011 realized as a reduction to the overall gain, and entered into new oil fixed price swaps for the same volumes and periods at ICE Brent prices.

FASB Accounting Standards define fair value, establish a framework for measuring fair value and establish required disclosures about fair value measurements. They also establish a fair value hierarchy that prioritizes the inputs to valuation techniques into three broad levels based upon how observable those inputs are. We use valuation techniques that maximize the use of observable inputs and obtain the majority of our inputs from published objective sources or third party market participants. We incorporate the impact of nonperformance risk, including credit risk, into our fair value measurements. The fair value hierarchy gives the highest priority of Level 1 to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority of Level 3 to unobservable inputs. We categorize our fair value financial instruments based upon the objectivity of the inputs and how observable those inputs are. The three levels of inputs are described further as follows:

Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Level 2 – Inputs other than quoted prices that are included in Level 1. Level 2 includes financial instruments that are actively traded but are valued using models or other valuation methodologies. We consider the over the counter (“OTC”) commodity and interest rate swaps in our portfolio to be Level 2. Level 3 – Inputs that are not directly observable for the asset or liability and are significant to the fair value of the asset or liability. Level 3 includes financial instruments that are not actively traded and have little or no observable data for input into industry standard models. Certain OTC derivatives that trade in less liquid markets or contain limited observable model inputs are currently included in Level 3. As of December 31, 2013 and 2012, our Level 3 derivative assets and liabilities consisted entirely of OTC commodity put and call options.

Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data. We had no transfers in or out of Levels 1, 2 or 3 during the years ended December 31, 2013, 2012 and 2011. Our policy is to recognize transfers between levels as of the end of the period.

Our Treasury/Risk Management group calculates the fair value of our commodity and interest rate swaps and options. We compare these fair value amounts to the fair value amounts that we receive from the counterparties on a monthly basis. Any differences are resolved and any required changes are recorded prior to the issuance of our financial statements.
The model we utilize to calculate the fair value of our Level 2 and Level 3 commodity derivative instruments is a standard option pricing model. Level 2 inputs to the option pricing models include fixed monthly commodity strike prices and volumes from each specific contract, commodity prices from commodity forward price curves, volatility and interest rate factors and time to expiry. Model inputs are obtained from our counterparties and third party data providers and are verified to published data where available (e.g., NYMEX). Additional inputs to our Level 3 derivatives include option volatility, forward commodity prices and risk-free interest rates for present value discounting. We use the standard swap contract valuation method to value our interest rate derivatives, and inputs include LIBOR forward interest rates, one-month LIBOR rates and risk-free interest rates for present value discounting.

Assumed credit risk adjustments, based on published credit ratings and credit default swap rates, are applied to our derivative instruments.

Our assessment of the significance of an input to its fair value measurement requires judgment and can affect the valuation of the assets and liabilities as well as the category within which they are classified. Financial assets and liabilities carried at fair value on a recurring basis are presented in the following tables:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>Level 1</th>
<th>Level 2</th>
<th>Level 3</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>As of December 31, 2013</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assets (liabilities)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil swaps</td>
<td>$ —</td>
<td>$ 5,573</td>
<td>$ —</td>
<td>$ 5,573</td>
</tr>
<tr>
<td>Oil collars</td>
<td>—</td>
<td>—</td>
<td>2,683</td>
<td>2,683</td>
</tr>
<tr>
<td>Oil puts</td>
<td>—</td>
<td>—</td>
<td>6,275</td>
<td>6,275</td>
</tr>
<tr>
<td>Natural gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural gas swaps</td>
<td>—</td>
<td>35,419</td>
<td>—</td>
<td>35,419</td>
</tr>
<tr>
<td>Natural gas calls</td>
<td>—</td>
<td>—</td>
<td>(650)</td>
<td>(650)</td>
</tr>
<tr>
<td>Natural gas puts</td>
<td>—</td>
<td>—</td>
<td>2,497</td>
<td>2,497</td>
</tr>
<tr>
<td>Net assets</td>
<td>$ —</td>
<td>$ 40,992</td>
<td>$ 10,805</td>
<td>$ 51,797</td>
</tr>
<tr>
<td>As of December 31, 2012</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assets (liabilities)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil swaps</td>
<td>$ —</td>
<td>$ (12,413)</td>
<td>$ —</td>
<td>$ (12,413)</td>
</tr>
<tr>
<td>Oil collars</td>
<td>—</td>
<td>—</td>
<td>4,024</td>
<td>4,024</td>
</tr>
<tr>
<td>Oil puts</td>
<td>—</td>
<td>—</td>
<td>11,144</td>
<td>11,144</td>
</tr>
<tr>
<td>Natural gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural gas swaps</td>
<td>—</td>
<td>74,782</td>
<td>—</td>
<td>74,782</td>
</tr>
<tr>
<td>Natural gas calls</td>
<td>—</td>
<td>—</td>
<td>(1,489)</td>
<td>(1,489)</td>
</tr>
<tr>
<td>Natural gas puts</td>
<td>—</td>
<td>—</td>
<td>3,162</td>
<td>3,162</td>
</tr>
<tr>
<td>Net assets</td>
<td>$ —</td>
<td>$ 62,369</td>
<td>$ 16,841</td>
<td>$ 79,210</td>
</tr>
</tbody>
</table>

F-21
The following table sets forth a reconciliation of changes in fair value of our derivative instruments classified as Level 3:

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oil</td>
<td>Natural Gas</td>
<td>Oil</td>
</tr>
<tr>
<td>Assets (a):</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beginning balance</td>
<td>$15,169</td>
<td>$1,672</td>
<td>$8,509</td>
</tr>
<tr>
<td>Derivative instrument settlements (b)</td>
<td>(125)</td>
<td>(892)</td>
<td>14,131</td>
</tr>
<tr>
<td>Gain (loss) (b)(c)</td>
<td>(6,087)</td>
<td>1,068</td>
<td>(20,760)</td>
</tr>
<tr>
<td>Purchases (b)(d)</td>
<td>—</td>
<td>—</td>
<td>13,288</td>
</tr>
<tr>
<td>Ending balance</td>
<td>$8,957</td>
<td>$1,848</td>
<td>$15,169</td>
</tr>
</tbody>
</table>

(a) We had no fair value changes for our derivative instruments classified as Level 3 related to sales or issuances.
(b) Included in gain (loss) on commodity derivative instruments, net on the consolidated statements of operations.
(c) Represents gain (loss) on mark-to-market of derivative instruments.
(d) Relates to natural gas put options entered into in June 2012 and oil options entered into in August 2012.

For Level 3 derivatives measured at fair value on a recurring basis as of December 31, 2013, the significant unobservable inputs used in the fair value measurements were as follows:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>Fair Value at December 31, 2013</th>
<th>Valuation Technique</th>
<th>Unobservable Input</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil options</td>
<td>$8,957</td>
<td>Option Pricing Model</td>
<td>Oil forward commodity prices</td>
<td>$81.95/Bbl - $105.14/Bbl</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Oil volatility</td>
<td>15.51% - 17.59%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Own credit risk</td>
<td>5%</td>
</tr>
<tr>
<td>Natural gas options</td>
<td>1,848</td>
<td>Option Pricing Model</td>
<td>Gas forward commodity prices</td>
<td>$4.01/MMBtu - $4.41/MMBtu</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Gas volatility</td>
<td>18.87% - 35.13%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Own credit risk</td>
<td>5%</td>
</tr>
<tr>
<td>Total</td>
<td>$10,805</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

For Level 3 derivatives measured at fair value on a recurring basis as of December 31, 2012, the significant unobservable inputs used in the fair value measurements were as follows:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>Fair Value at December 31, 2012</th>
<th>Valuation Technique</th>
<th>Unobservable Input</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil options</td>
<td>$15,169</td>
<td>Option pricing model</td>
<td>Oil forward commodity prices</td>
<td>$86.78/Bbl - $110.46/Bbl</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Oil volatility</td>
<td>20.56% - 27.53%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Own credit risk</td>
<td>5%</td>
</tr>
<tr>
<td>Natural gas options</td>
<td>1,672</td>
<td>Option pricing model</td>
<td>Gas forward commodity prices</td>
<td>$3.35/MMBtu - $4.87/MMBtu</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Gas volatility</td>
<td>20.55% - 35.88%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Own credit risk</td>
<td>5%</td>
</tr>
<tr>
<td>Total</td>
<td>$16,841</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Credit and Counterparty Risk

Financial instruments, which potentially subject us to concentrations of credit risk consist principally of derivatives and accounts receivable. Our derivatives expose us to credit risk from counterparties. As of December 31, 2013, our derivative counterparties were Barclays Bank PLC, Bank of Montreal, Citibank, N.A, Credit Suisse Energy LLC, Union Bank N.A, Wells Fargo Bank National Association, JP Morgan Chase Bank N.A., The Royal Bank of Scotland plc, The Bank of Nova Scotia, BNP Paribas, U.S Bank National Association, Toronto-Dominion Bank and Royal Bank of Canada. Our counterparties are all lenders under our Amended and Restated Credit Agreement. Our credit agreement is secured by our oil, NGL and natural gas reserves, so we are not required to post any collateral, and we conversely do not receive collateral from our counterparties. On all transactions where we are exposed to counterparty risk, we analyze the counterparty’s financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We periodically obtain credit default swap information on our counterparties. Although we currently do not believe we have a specific counterparty risk with any party, our loss could be substantial if any of these parties were to fail to perform in accordance with the terms of the contract. This risk is managed by diversifying our derivatives portfolio. As of December 31, 2013, each of these financial institutions had an investment grade credit rating. As of December 31, 2013, our largest derivative asset balances were with Wells Fargo Bank National Association, Credit Suisse Energy LLC and Citibank, N.A., which accounted for approximately 30%, 26% and 13% of our derivative asset balances, respectively.

5. Related Party Transactions

BreitBurn Management operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. All of our employees, including our executives, are employees of BreitBurn Management. BreitBurn Management also operates the assets of PCEC, our Predecessor. In addition to a monthly fee for indirect expenses, BreitBurn Management charges PCEC for all direct expenses, including incentive plan costs and direct payroll and administrative costs related to PCEC properties and operations.

On January 6, 2012, Pacific Coast Oil Trust (the “Trust”), which was formed by PCEC, filed a registration statement on Form S-1 with the SEC in connection with an initial public offering by the Trust. On May 8, 2012, the Trust completed its initial public offering (the “Trust IPO”). We have no direct or indirect ownership interest in PCEC or the Trust. As part of the Trust IPO, PCEC conveyed net profits interests in its oil and natural gas production from certain of its properties to the Trust in exchange for Trust units. PCEC’s assets consist primarily of producing and non-producing oil reserves located in Santa Barbara, Los Angeles and Orange Counties in California, including certain interests in the East Coyote and Sawtelle Fields. Prior to the Trust IPO, PCEC operated the East Coyote and Sawtelle Fields for us and for its benefit. PCEC owned an average working interest of approximately 5% in the two fields and held a reversionary interest in both fields that was expected to result in an increase in PCEC’s ownership and accordingly decrease in our ownership in the properties. After the Trust IPO, PCEC’s ownership interest in both properties increased, and our ownership in these properties decreased from approximately 95% to 62%.

On May 8, 2012, BreitBurn Management entered into the Third Amended and Restated Administrative Services Agreement (the “Third Amended and Restated Administrative Services Agreement”) with PCEC, pursuant to which the parties agreed to increase the monthly fee charged by BreitBurn Management to PCEC for indirect costs. For the first three months of 2012, the monthly fee charged by BreitBurn Management to PCEC for indirect costs was set at $571,000, and the two parties agreed to increase that monthly fee to $700,000, effective April 1, 2012. In connection with the PCEC transactions and the Third Amended and Restated Administrative Services Agreement, PCEC also paid us a $250,000 fee.

In connection with the Trust IPO, we, BreitBurn GP, LLC and BreitBurn Management entered into the First Amendment to Omnibus Agreement, dated as of May 8, 2012, with PCEC, Pacific Coast Energy Holdings LLC, formerly known as BreitBurn Energy Holdings, LLC, and PCEC (GP) LLC, formerly known as BEC (GP) LLC (the “First Amendment to Omnibus Agreement”). Pursuant to the First Amendment to Omnibus Agreement, the parties agreed to amend the Omnibus Agreement among the parties, dated as of August 26, 2008 (the “Omnibus Agreement”), to remove Article III of the Omnibus Agreement, which contained our right of first offer with respect to the sale of assets by PCEC and its affiliates.
At December 31, 2013 and 2012, we had net current receivables of $2.5 million and $1.2 million, respectively, due from PCEC related to the applicable administrative services agreement, employee related costs and oil and gas sales made by PCEC on our behalf from certain properties. During 2013, the monthly charges to PCEC for indirect expenses totaled $8.4 million and charges for direct expenses including direct payroll and other direct costs totaled $10.6 million. During 2012, the monthly charges to PCEC for indirect expenses totaled $8.0 million and charges for direct expenses including direct payroll and other direct costs totaled $8.6 million.

At December 31, 2013 and 2012, we had receivables of $0.1 million and $0.2 million, respectively, due from certain of our other affiliates primarily representing investments in natural gas processing facilities for management fees due from them and operational expenses incurred on their behalf.

6. Inventory

As of December 31, 2013 and 2012, our Florida operations had oil inventory of $3.9 million and $3.1 million, respectively. For the year ended December 31, 2013, we sold 784 MBbls of oil and produced 779 MBbls from our Florida operations. For the year ended December 31, 2012, we sold 849 MBbls of oil and produced 830 MBbls from our Florida operations. Oil sales are a function of the number and size of oil shipments in each quarter, and thus, oil sales do not always coincide with volumes produced in a given quarter. We match production expenses with oil sales. Production expenses associated with unsold oil inventory are recorded as inventory.

We carry inventory at the lower of cost or market. When using lower of cost or market to value inventory, market should not exceed the net realizable value or the estimated selling price less costs of completion and disposal. We assessed our oil inventory at December 31, 2013 and December 31, 2012 and determined that its carrying value was below market value and therefore no write-down were necessary.

For our properties in Florida, there are a limited number of alternative methods of transportation for our production. Substantially all of our oil production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of our oil production, which could have a negative impact on our future consolidated financial position, results of operations and cash flows.

7. Equity Investments

We had equity investments at December 31, 2013 and December 31, 2012 totaling $6.6 million and $7.0 million, respectively, which primarily represent investments in natural gas processing facilities and product transportation pipelines. For the years ended December 31, 2013 and 2012, we recorded $0.5 million and $0.7 million, respectively, in earnings from equity investments and $0.5 million and $1.2 million, respectively, in dividends. In 2013, we dissolved one of our partnerships, which reduced the carrying value of our investments by $0.4 million. For the year ended December 31, 2011, we recorded $0.7 million in earnings from equity investments and $0.9 million in dividends. Earnings from equity investments are reported in other revenue, net on the consolidated statements of operations.

At December 31, 2013, our equity investments consisted primarily of a 24.5% limited partner interest and a 25.5% general partner interest in Wilderness Energy Services LP, with a combined carrying value of $6.0 million. The remaining $0.6 million consists of smaller interests in several other investments where we have significant influence.

8. Impairments

We assess our developed and undeveloped oil and gas properties and other long-lived assets for possible impairment periodically and whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include changes in business plans, changes in commodity prices and, for oil and natural gas properties, significant downward revisions of estimated proved reserve quantities. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge is recorded for the excess of carrying value of the asset over its estimated fair value.

F-24
Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for market supply and demand conditions for oil and natural gas. For purposes of performing an impairment test, the undiscounted future cash flows are based on total proved and risk-adjusted probable and possible reserves and are forecast using five-year NYMEX forward strip prices at the end of the period and escalated along with expenses and capital starting year six and thereafter at 2.5% per year. For impairment charges, the associated property’s expected future net cash flows are discounted using a market-based weighted average cost of capital rate that currently approximates 10%. Additional inputs include oil and natural gas reserves, future operating and development costs and future commodity prices. We consider the inputs for our impairment calculations to be Level 3 inputs. The impairment reviews and calculations are based on assumptions that are consistent with our business plans.

During the year ended December 31, 2013, we recorded non-cash impairment charges of approximately $54.4 million, including $28.3 million of impairments to our Michigan non-Antrim oil and gas properties due to negative reserve adjustments due to lower performance and a decrease in expected future commodity prices, and $25.3 million of impairments to an oil property in our Bighorn Basin in Northern Wyoming due to a negative reserve adjustment due to lower performance and a decrease in expected future oil prices. Decreased drilling activity in Michigan was also a factor as the Partnership continues to allocate its capital expenditures more towards liquids-rich areas. During the year ended December 31, 2012, we recorded impairments of approximately $12.3 million primarily related to uneconomic proved properties in Michigan, Indiana and Kentucky due to a decrease in expected future natural gas prices. During the year ended December 31, 2011, we recorded impairments of approximately $0.6 million related to uneconomic proved properties in Michigan primarily due to a decrease in expected natural gas prices.

Given the number of assumptions involved in the estimates, an estimate as to the sensitivity to earnings for these periods if other assumptions had been used in impairment reviews and calculations is not practicable. Favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

9. Other Assets

Intangible Assets

In connection with the Whiting Acquisition (see Note 3), we acquired two CO₂ purchase contracts that were priced below market, which were valued at $14.7 million at the acquisition date. These contracts were recorded as finite-lived intangibles. We amortize intangible assets with finite lives over their estimated useful lives. We are amortizing these contracts based on the amount of CO₂ purchases made in each period over the contracts’ respective lives. The first contract was scheduled to expire in December 2014 when the contract was novated to us as part of the Whiting Acquisition. In December 2013, we have amended the volume and price components of that contract with the seller to extend the term of the contract to December 2015. The second contract expires in September 2023. For the year ended December 31, 2013, we recorded $3.6 million in amortization expense related to these contracts. As of December 31, 2013, we had a remaining unamortized value of $11.1 million.

The table below shows our estimated amortization expense related to our acquired CO₂ contracts for each of the next five years and thereafter:

<table>
<thead>
<tr>
<th>Intangible assets amortization</th>
<th>Year Ended December 31,</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
<td>2015</td>
<td>2016</td>
<td>2017</td>
<td>2018</td>
<td>Thereafter</td>
<td>Total</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$ 5,873</td>
<td>$ 879</td>
<td>$ 793</td>
<td>$ 710</td>
<td>$ 638</td>
<td>$ 2,276</td>
<td>$ 11,169</td>
<td></td>
</tr>
</tbody>
</table>

California’s AB 32 requires the state to reduce statewide GHG emissions to 1990 levels by 2020. To meet this benchmark, the California Air Resources Board (“CARB”) has promulgated a number of regulations, including the Cap-and-Trade Regulation and Mandatory Reporting Rule, which took effect on January 1, 2012. These regulations were further amended by the CARB in 2012. Under the Cap-and-Trade Regulation, the first compliance period for covered entities like our partnership began on January 1, 2013 and runs through the end of 2014. The second and third compliance periods cover 2015 through 2017 and 2018 through 2020, respectively. Covered entities must hold and
surrender compliance instruments, which include allowances and offsets, in an amount equivalent to their emissions from sources of GHG located in California.

In connection with our compliance with the California GHG Cap-and-Trade Regulation, we purchased $0.5 million of GHG allowances in 2013 auctions. We recognized the purchase of these allowances as intangibles until they are surrendered in compliance with regulations promulgated by CARB.

Other long-term assets

As of December 31, 2013, our other long-term assets were $74.2 million which included $35.6 million in debt issuance costs (see Note 10 for further details), $22.6 million in advances made for the purchase of future CO₂ supply for our Oklahoma properties, $15.0 million deposit that we made relating to negotiations undertaken to secure additional future CO₂ supply for our Oklahoma properties and $1.0 million in other long-term assets. The $22.6 million in advances included $10.9 million that was part of the Whiting Acquisition purchase price allocation (see Note 3). The amount in excess of the $10.9 million was incurred after the closing of the acquisition. For the period ended September 30, 2013 in our third quarter Form 10-Q, we reported $14.7 million of this advance as a deduction of our net cash flow provided from operating activities on our consolidated statements of cash flows instead of cash flow used in investing activities. For the year ended December 31, 2013, the consolidated statements of cash flows now reflects this advance as cash flow used in investing activities. We concluded that the impact of this correction was not material to the current year or any prior period.

10. Long-Term Debt

Credit Facility

BOLP, as borrower, and we and our wholly-owned subsidiaries, as guarantors, have a $3.0 billion revolving credit facility with Wells Fargo Bank National Association, as Administrative Agent, Swing Line Lender and Issuing Lender, and a syndicate of banks (the “Second Amended and Restated Credit Agreement”) with a maturity date of May 9, 2016.

Our credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base is redetermined semi-annually. Currently, our borrowing base for our credit facility is $1.5 billion, and the aggregate commitment of all lenders is $1.4 billion with the ability to increase our total commitments up to the $1.5 billion borrowing base upon lender approval. Our next borrowing base redetermination is scheduled for April 2014.

In May 2013, we entered into the Eighth Amendment to the Second Amended and Restated Credit Agreement, which increased our borrowing base to $1.2 billion and the aggregate commitment of all lenders to $1.0 billion, and which added eight lenders to our syndicate.

In July 2013, we entered into the Ninth Amendment to the Second Amended and Restated Credit Agreement, which increased our aggregate maximum credit amount from $1.5 billion to $3.0 billion, increased our borrowing base to $1.5 billion and increased the aggregate commitment of all lenders to $1.4 billion. The amendment also increased flexibility for the Total Leverage Ratio (defined as the ratio of total debt to EBITDAX). Both of these leverage ratios were eliminated from our credit facility in connection with the Eleventh Amendment (the “Eleventh Amendment”) to the Second Amended and Restated Credit Agreement discussed below.

In November 2013, we entered into the Tenth Amendment to the Second Amended and Restated Credit Agreement, which permitted us to declare and pay to our equity owners periodic cash dividends in accordance with our partnership agreement.

In February 2014, we entered into the Eleventh Amendment that eliminated the Maximum Total Leverage Ratio (defined as the ratio of total debt to EBITDAX) and Maximum Senior Secured Leverage Ratio (defined as the ratio of senior secured indebtedness to EBITDAX) requirements and added a provision requiring us to maintain an Interest Coverage Ratio (defined as EBITDAX divided by Consolidated Interest Expense) for the four quarters ending on the last day of each quarter beginning with the fourth quarter of 2013 of no less that 2.50 to 1.00. The amendment also provides that we cannot incur senior unsecured debt in excess of our borrowing base in effect at the time of the issuance of such debt.

EBITDAX is not a defined US GAAP measure. The Second Amended and Restated Credit Agreement defines EBITDAX as consolidated net income plus exploration expense, interest expense, income tax provision, DD&A, unrealized loss or gain on derivative instruments, non-cash charges, including non-cash unit-based compensation expense, loss or gain on sale of assets (excluding gain or loss on monetization of derivative instruments for the following twelve months), pro forma impact of acquisitions and disposition, cumulative effect of changes in accounting principles, cash distributions received from our unrestricted entities (as defined in the Second Amended and Restated Credit Agreement) and excluding income from our unrestricted entities.

As of December 31, 2013 and December 31, 2012, our borrowing base was $1.5 billion and $1.0 billion, respectively, and the aggregate commitment of all lenders was $1.4 billion and $900 million, respectively.
As of December 31, 2013 and December 31, 2012, we had $733.0 million and $345.0 million, respectively, in indebtedness outstanding under the credit facility. At December 31, 2013, the 1-month LIBOR interest rate plus an applicable spread was 2.167% on the 1-month LIBOR portion of $727.0 million and the prime rate plus an applicable spread was 4.25% on the prime portion of $6.0 million. At December 31, 2013, we had $13.7 million of unamortized debt issuance costs related to our credit facility.

Borrowings under the Second Amended and Restated Credit Agreement are secured by first-priority liens on and security interests in substantially all of our and certain of our subsidiaries’ assets, representing not less than 80% of the total value of our oil and gas properties.

The Second Amended and Restated Credit Agreement contains customary covenants, including restrictions on our ability to: incur additional indebtedness; make certain investments, loans or advances; make distributions to our unitholders or repurchase units (including the restriction on our ability to make distributions unless, after giving effect to such distribution, we remain in compliance with all terms and conditions of our credit facility); make dispositions or enter into sales and leasebacks; or enter into a merger or sale of our property or assets, including the sale or transfer of interests in our subsidiaries.

The Second Amended and Restated Credit Agreement also permits us to terminate derivative contracts without obtaining the consent of the lenders in the facility, provided that the net effect of such termination plus the aggregate value of all dispositions of oil and gas properties made during such period, together, does not exceed 5% of the borrowing base; and the borrowing base will be automatically reduced by an amount equal to the net effect of the termination.

The events that constitute an Event of Default (as defined in the Second Amended and Restated Credit Agreement) include: payment defaults; misrepresentations; breaches of covenants; cross-default and cross-acceleration to certain other indebtedness; adverse judgments against us in excess of a specified amount; changes in management or control; loss of permits; certain insolvency events; and assertion of certain environmental claims.

As of December 31, 2013, we were in compliance with our credit facility’s covenants.

**Senior Notes Due 2020**

On October 6, 2010, we and BreitBurn Finance Corporation (the “Issuers”), and certain of our subsidiaries as guarantors (the “Guarantors”), issued $305 million in aggregate principal amount of 8.625% Senior Notes due 2020 (the “2020 Senior Notes”). The 2020 Senior Notes were offered at a discount price of 98.358%, or $300 million. The $5 million discount is being amortized over the life of the 2020 Senior Notes. As of December 31, 2013 and 2012, the 2020 Senior Notes had a carrying value of $301.6 million and $301.1 million, respectively, net of unamortized discount of $3.4 million and $3.9 million, respectively. In connection with the 2020 Senior Notes, we incurred financing fees and expenses of approximately $8.8 million, which are being amortized over the life of the 2020 Senior Notes. Interest on the 2020 Senior Notes is payable twice a year in April and October.
As of December 31, 2013 and 2012, the fair value of the 2020 Senior Notes was estimated to be $327 million and $330 million, respectively. We consider the inputs to the valuation of our 2020 Senior Notes to be Level 2, as fair value was estimated based on prices quoted from third party financial institutions.

**Senior Notes Due 2022**

On January 10, 2012, the Issuers, and certain of our subsidiaries as Guarantors, issued $250 million in aggregate principal amount of 7.875% Senior Notes due 2022 (the “Initial Notes”), which were purchased by the initial purchasers as defined in the purchase agreement (the “Initial Purchasers”) and then resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended (the “Securities Act”). The Initial Notes were issued at a discount of 99.154%, or $247.9 million. The $2.1 million discount is being amortized over the life of the Initial Notes. In connection with the Initial Notes, our financing fees and expenses were approximately $5.6 million, which are being amortized over the life of the Initial Notes.

On September 27, 2012 we issued an additional $200 million aggregate principal amount of our 7.875% Senior Notes due 2022 (the “2012 Additional Notes”), which were purchased by the Initial Purchasers and then resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act. The 2012 Additional Notes have identical terms, other than the issue date and initial interest payment date, and constitute part of the same series as and are fungible with the Initial Notes. The 2012 Additional Notes were issued at a premium of 103.500%, or $207.0 million. The $7.0 million premium is being amortized over the life of the 2012 Additional Notes. In connection with the 2012 Additional Notes, our financing fees and expenses were approximately $4.2 million, which are being amortized over the life of the 2012 Additional Notes.

In connection with the issuance of the Initial Notes and the 2012 Additional Notes, we entered into Registration Rights Agreements (the “Registration Rights Agreements”) with the Guarantors and Initial Purchasers. Under the Registration Rights Agreements, the Issuers and the Guarantors agreed to cause to be filed with the SEC a registration statement with respect to an offer to exchange these notes for substantially identical notes that are registered under the Securities Act. The Issuers and the Guarantors agreed to use their commercially reasonable efforts to cause such exchange offer registration statement to become effective under the Securities Act. In addition, the Issuers and the Guarantors agreed to use their commercially reasonable efforts to cause the exchange offer to be consummated not later than 400 days after January 13, 2012. In December 2012, we filed a registration statement for the exchange offer for the Initial Notes and the 2012 Additional Notes. On December 27, 2012, the exchange registration statement became effective, and we commenced the exchange offer, which was completed on February 7, 2013.

On November 22, 2013, we completed a public offering of $400 million aggregate principal amount of our 7.875% Senior Notes due 2022 (the “2013 Additional Notes” and together with the 2012 Additional Notes and the Initial Notes, as the “2022 Senior Notes”). The 2013 Additional Notes have identical terms, other than the issue date and initial interest payment date, and constitute part of the same series as and are fungible with the Initial Notes. The 2013 Additional Notes were issued at a premium of 100.250%, or $401.0 million. The $1.0 million premium is being amortized over the life of the 2013 Additional Notes. In connection with the 2013 Additional Notes, our financing fees and expenses were approximately $7.7 million, which are being amortized over the life of the 2013 Additional Notes.

As of December 31, 2013, the 2022 Senior Notes had a carrying value of $855.1 million, net of unamortized premium of $5.1 million. Interest on the 2022 Senior Notes is payable twice a year in April and October. As of December 31, 2013, the fair value of the 2022 Senior Notes was estimated to be $890 million. We consider the inputs to the valuation of our 2022 Senior Notes to be Level 2, as fair value was estimated based on prices quoted from third party financial institutions.

The indentures governing both our 2020 Senior Notes and 2022 Senior Notes contain covenants that restrict our ability and the ability of certain of our subsidiaries to: (i) sell assets including equity interests in our subsidiaries; (ii) pay distributions on, redeem or repurchase our units or redeem or repurchase our subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates; (ix) create unrestricted subsidiaries; or (x) engage in certain business activities. If the senior notes achieve an investment grade rating from each
of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no Default (as defined in the indentures) has occurred and is continuing, many of these covenants will terminate.

As of December 31, 2013 and December 31, 2012, we were in compliance with the covenants on our 2020 and 2022 Senior Notes.

Interest Expense

Our interest expense is detailed in the following table:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Credit facility (including commitment fees)</td>
<td>$15,698</td>
<td>$7,114</td>
<td>$8,266</td>
</tr>
<tr>
<td>Senior notes</td>
<td>65,068</td>
<td>49,279</td>
<td>26,233</td>
</tr>
<tr>
<td>Amortization of discount and deferred issuance costs</td>
<td>6,429</td>
<td>4,867</td>
<td>4,743</td>
</tr>
<tr>
<td>Capitalized interest</td>
<td>(128)</td>
<td>(54)</td>
<td>(77)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$87,067</td>
<td>$61,206</td>
<td>$39,165</td>
</tr>
<tr>
<td>Cash paid for interest</td>
<td>$74,078</td>
<td>$55,151</td>
<td>$37,756</td>
</tr>
</tbody>
</table>

11. Condensed Consolidating Financial Statements

We and BreitBurn Finance Corporation as co-issuers, and certain of our subsidiaries as guarantors, issued the 2020 Senior Notes and the 2022 Senior Notes. All but one of our subsidiaries have guaranteed our senior notes. Our only non-guarantor subsidiary, BreitBurn Collingwood Utica LLC, is a minor subsidiary.

In accordance with Rule 3-10 of Regulation S-X, we are not presenting condensed consolidating financial statements as we have no independent assets or operations; BreitBurn Finance Corporation, the subsidiary co-issuer which does not guarantee our senior notes, is a 100% owned finance subsidiary; all of our material subsidiaries are 100% owned, have guaranteed our senior notes, and all of the guarantees are full, unconditional, joint and several.

Each guarantee of each of the 2020 Senior Notes and the 2022 Senior Notes is subject to release in the following customary circumstances:

1. a disposition of all or substantially all the assets of the guarantor subsidiary (including by way or merger or consolidation), to a third person, provided the disposition complies with the applicable indenture,
2. a disposition of the capital stock of the guarantor subsidiary to a third person, if the disposition complies with the applicable indenture and as a result the guarantor subsidiary ceases to be our subsidiary,
3. the designation by us of the guarantor subsidiary as an Unrestricted Subsidiary in accordance with the applicable indenture,
4. legal or covenant defeasance of such series of Senior Notes or satisfaction and discharge of the related indenture,
5. the liquidation or dissolution of the guarantor subsidiary, provided no default under the applicable indenture exists, or
6. the guarantor subsidiary ceases both (a) to guarantee any other indebtedness of ours or any other guarantor subsidiary and (b) to be an obligor under any bank credit facility.

12. Income Taxes

We, and all of our subsidiaries, with the exception of Phoenix Production Company (“Phoenix”), Alamitos Company, BreitBurn Management and BreitBurn Finance Corporation, are partnerships or limited liability companies treated as partnerships for federal and state income tax purposes. Essentially all of our taxable income or loss, which may differ considerably from the net income or loss reported for financial reporting purposes, is passed through to the federal
income tax returns of our partners. As such, we have not recorded any federal income tax expense for those pass-through entities.

The consolidated income tax expense (benefit) attributable to our tax-paying entities consisted of the following:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>Year Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td><strong>Federal income tax expense (benefit)</strong></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>$ 472</td>
</tr>
<tr>
<td>Deferred (a)</td>
<td>262</td>
</tr>
<tr>
<td>State income tax expense (b)</td>
<td>171</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 905</td>
</tr>
</tbody>
</table>

(a) Related to Phoenix, our wholly-owned subsidiary.
(b) Primarily in California, Texas and Michigan.

The following is a reconciliation of federal income taxes at the statutory rates to federal income tax expense (benefit) for Phoenix:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>Year Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td>Income (loss) subject to federal income tax</td>
<td>$ 750</td>
</tr>
<tr>
<td>Federal income tax rate</td>
<td>34%</td>
</tr>
<tr>
<td>Income tax at statutory rate</td>
<td>255</td>
</tr>
<tr>
<td>Statutory depletion from prior year</td>
<td>—</td>
</tr>
<tr>
<td>Other</td>
<td>13</td>
</tr>
<tr>
<td><strong>Income tax expense (benefit)</strong></td>
<td>$ 268</td>
</tr>
</tbody>
</table>

At December 31, 2013 and 2012, net deferred federal income tax liabilities of $2.7 million and $2.5 million, respectively, were reported in our consolidated balance sheet for Phoenix. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting and the amount used for income tax purposes. Significant components of our net deferred tax liabilities are presented in the following table:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td><strong>Deferred tax assets:</strong></td>
<td></td>
</tr>
<tr>
<td>Asset retirement obligation</td>
<td>$ 526</td>
</tr>
<tr>
<td>Unrealized hedge loss</td>
<td>51</td>
</tr>
<tr>
<td>Deferred realized hedge loss</td>
<td>—</td>
</tr>
<tr>
<td>Other</td>
<td>627</td>
</tr>
<tr>
<td><strong>Deferred tax liabilities:</strong></td>
<td></td>
</tr>
<tr>
<td>Depreciation, depletion and intangible drilling costs</td>
<td>(3,953)</td>
</tr>
<tr>
<td><strong>Net deferred tax liability</strong></td>
<td>$ (2,749)</td>
</tr>
</tbody>
</table>

At December 31, 2013, we had unused carryforwards of operating loss and minimum tax credit. We did not provide a valuation allowance against these deferred tax asset as we expect to fully utilize the carryforwards in the future.

On a consolidated basis, cash paid for federal and state income taxes totaled $0.5 million, $0.8 million and $0.3 million in 2013, 2012 and 2011, respectively.
FASB Accounting Standards clarify the accounting for uncertainty in income taxes recognized in a company’s financial statements. A company can only recognize the tax position in the financial statements if the position is more-likely-than-not to be upheld on audit based only on the technical merits of the tax position. FASB Accounting Standards also provide guidance on thresholds, measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition that is intended to provide better financial statement comparability among different companies.

We performed analysis as of December 31, 2013, 2012 and 2011 and concluded that there were no uncertain tax positions requiring recognition in our financial statements.

13. Asset Retirement Obligation

ARO is based on our net ownership in wells and facilities and our estimate of the costs to abandon and remediate those wells and facilities together with our estimate of the future timing of the costs to be incurred. Payments to settle ARO occur over the operating lives of the assets, estimated to range from less than one year to 50 years. Estimated cash flows have been discounted at our credit adjusted risk free rate that approximates 7% and adjusted for inflation using a rate of 2%. Our credit adjusted risk free rate is calculated based on our cost of borrowing adjusted for the effect of our credit standing and specific industry and business risk.

During 2013 and 2012, we added ARO of $9.3 million and $6.3 million, respectively, from acquisitions. During 2013, we added $5.3 million reflecting increases in the number of wells drilled during the year.

Each year we review and, to the extent necessary, revise our ARO estimates. During 2013 and 2012, we obtained new estimates to evaluate the cost of abandoning our properties. As a result, we increased our ARO estimate by $4.3 million in 2013 to reflect primarily increases in cost estimates. Revisions in 2012 of $1.6 million reflect increases in estimated costs for plugging and abandonment, primarily in Wyoming and Florida, partially offset by a decrease in ARO related to the change in working interest ownership in two California fields.

We consider the inputs to our ARO valuation to be Level 3 as fair value is determined using discounted cash flow methodologies based on standardized inputs that are not readily observable in public markets.

Changes in the ARO are presented in the following table:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>Year Ended December 31,</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2012</td>
<td></td>
</tr>
<tr>
<td>Carrying amount, beginning of period</td>
<td>$98,480</td>
<td>$82,397</td>
<td></td>
</tr>
<tr>
<td>Acquisitions</td>
<td>9,287</td>
<td>6,279</td>
<td></td>
</tr>
<tr>
<td>Liabilities incurred</td>
<td>5,313</td>
<td>2,468</td>
<td></td>
</tr>
<tr>
<td>Liabilities settled</td>
<td>(893)</td>
<td>(86)</td>
<td></td>
</tr>
<tr>
<td>Revisions</td>
<td>4,299</td>
<td>1,553</td>
<td></td>
</tr>
<tr>
<td>Accretion expense</td>
<td>7,283</td>
<td>5,869</td>
<td></td>
</tr>
<tr>
<td>Carrying amount, end of period</td>
<td>$123,769</td>
<td>$98,480</td>
<td></td>
</tr>
</tbody>
</table>

14. Commitments and Contingencies

Lease Rental and Purchase Obligations

We have operating leases for office space and other property and equipment having initial or remaining non-cancelable lease terms in excess of one year. Our future minimum rental payments for operating leases at December 31, 2013 are presented below:
Net rental expense under non-cancelable operating leases was $3.9 million, $3.7 million and $3.4 million in 2013, 2012 and 2011, respectively.

**Purchase Contracts**

On July 15, 2013, we completed the Whiting Acquisition. The Whiting Acquisition included the Postle Field, which currently has active CO₂ enhanced recovery projects, and the Northeast Hardesty Unit, both of which are located in Texas County, Oklahoma. We have a contracted supply of CO₂ in the Bravo Dome Field in New Mexico, with step-in rights, for 143 Bcf over the next 10 to 15 years, which we expect to provide volumes in excess of those required to produce our estimated proved reserves when coupled with recycled CO₂. Under the take-or-pay provisions of these purchase agreements, we are committed to buying certain volumes of CO₂ for use in our enhanced recovery project being carried out at the Postle field. We are obligated to purchase a minimum daily volume of CO₂ (as calculated on an annual basis) or otherwise pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. The CO₂ volumes planned for use in our enhanced recovery projects in the Postle Field currently exceed the minimum daily volumes specified in these agreements. Therefore, we expect to avoid any deficiency payments. The table below shows our future minimum commitments under these purchase agreements as of December 31, 2013:

<table>
<thead>
<tr>
<th>Payments Due by Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Thereafter</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating leases</td>
<td>$5,910</td>
<td>$5,530</td>
<td>$4,498</td>
<td>$4,068</td>
<td>$633</td>
<td>$—</td>
<td>$20,639</td>
</tr>
</tbody>
</table>

**Surety Bonds and Letters of Credit**

In the normal course of business, we have performance obligations that are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily relate to abandonments, environmental and other responsibilities where governmental and other organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by us if drawn upon. At December 31, 2013, we had $17.5 million in surety bonds and $0.3 million in letters of credit outstanding. At December 31, 2012, we had $16.2 million in surety bonds and $0.3 million in letters of credit outstanding.

**Legal Proceedings**

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

**15. Partners’ Equity**

At December 31, 2013 and 2012, we had approximately 119.2 million and 84.7 million in Common Units outstanding, respectively.

In February 2013, we sold approximately 14.95 million Common Units at a price to the public of $19.86 per Common Unit, resulting in net proceeds of $285.0 million, after deducting underwriting discounts and expenses. In November 2013, we sold 18.98 million Common Units at a price to the public of $18.22 per Common Unit resulting in net proceeds net of $333.2 million, after deducting underwriting discounts and estimated offering expenses.

In February 2012, we sold 9.20 million Common Units at a price to the public of $18.80 per Common Unit, resulting in net proceeds of $166.0 million after deducting underwriting discounts and offering expenses. In September 2012, we sold 11.50 million of our Common Units at a price to the public of $18.51 per Common Unit, resulting in proceeds, net of underwriting discount and offering expenses, of $204.1 million. In November 2012, we issued 3.01
million Common Units to AEO as partial consideration for the AEO Acquisition. The fair value of the units on the date of the acquisition was $18.48 per unit, or $56 million.

During the years ended December 31, 2013, 2012, and 2011, approximately 1.3 million, 1.0 million and 1.2 million Common Units, respectively, were issued to employees and outside directors pursuant to vested grants under our First Amended and Restated 2006 Long Term Incentive Plan (“LTIP”).

At December 31, 2013 and December 31, 2012, we had 9.7 million and 9.7 million, respectively, of Common Units authorized for issuance under our long-term incentive compensation plans, and there were 0.6 million and 0.9 million, respectively, of Common Units outstanding under grants that are eligible to be paid in Common Units upon vesting.

**Earnings per common unit**

FASB Accounting Standards require use of the “two-class” method of computing earnings per unit for all periods presented. The “two-class” method is an earnings allocation formula that determines earnings per unit for each class of common unit and participating security as if all earnings for the period had been distributed. Unvested restricted unit awards that earn non-forfeitable distribution rights qualify as participating securities and, accordingly, are included in the basic computation. Our unvested Restricted Phantom Units (“RPUs”) and Convertible Phantom Units (“CPUs”) participate in distributions on an equal basis with Common Units. Accordingly, the presentation below is prepared on a combined basis and is presented as net income (loss) per common unit.

The following is a reconciliation of net income (loss) and weighted average units for calculating basic net income (loss) per common unit and diluted net income (loss) per common unit.

<table>
<thead>
<tr>
<th>Thousands, except per unit amounts</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income (loss) attributable to limited partners</td>
<td>$(43,671)</td>
<td>$(40,801)</td>
<td>$110,497</td>
</tr>
<tr>
<td>Distributions on participating units not expected to vest</td>
<td>21</td>
<td>82</td>
<td>29</td>
</tr>
<tr>
<td>Net income (loss) attributable to common unitholders and participating securities</td>
<td>$(43,650)</td>
<td>$(40,719)</td>
<td>$110,526</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Weighted average number of units used to calculate basic and diluted net income (loss) per unit:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Units</td>
</tr>
<tr>
<td>Participating securities (a)</td>
</tr>
<tr>
<td>Denominator for basic earnings per common unit</td>
</tr>
<tr>
<td>Dilutive units (b)</td>
</tr>
<tr>
<td>Denominator for diluted earnings per common unit</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Net income (loss) per common unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic</td>
</tr>
<tr>
<td>Diluted</td>
</tr>
</tbody>
</table>

(a) The year ended December 31, 2013 and 2012 excludes 1,649 and 2,452 of potentially issuable weighted average RPUs and CPUs from participating securities, respectively, as we were in a loss position.
(b) The year ended December 31, 2012 and 2012 excludes 364 and 55 weighted average anti-dilutive units from the calculation of the denominator for diluted earnings per common unit, respectively, as we were in a loss position.

**Cash Distributions**

The partnership agreement requires us to distribute all of our available cash quarterly. Available cash is cash on hand, including cash from borrowings, at the end of a quarter after the payment of expenses and the establishment of reserves for future capital expenditures and operational needs. We may fund a portion of capital expenditures with
additional borrowings or issuances of additional units. We may also borrow to make distributions to unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long term, but short-term factors have caused available cash from operations to be insufficient to pay the distribution at the current level. The partnership agreement does not restrict our ability to borrow to pay distributions. The cash distribution policy reflects a basic judgment that unitholders will be better served by us distributing our available cash, after expenses and reserves, rather than retaining it. Distributions are not cumulative. Consequently, if distributions on Common Units are not paid with respect to any fiscal quarter at the initial distribution rate, our unitholders will not be entitled to receive such payments in the future.

Prior to the fourth quarter of 2013, for the quarters for which we declared a distribution, distributions were paid within 45 days of the end of each fiscal quarter to holders of record on or about the first or second week of each such month. If the distribution date does not fall on a business day, the distribution will be made on the business day immediately preceding the indicated distribution date. On October 30, 2013, we amended our First Amended and Restated Agreement of Limited Partnership by adopting Amendment No. 5, which provided that, at the discretion of our General Partner, for the quarters for which we declare a distribution, we may pay distributions within 45 days following the end of each quarter or in three equal monthly payments within 17, 45 and 75 days following the end of each quarter. The Partnership changed its distribution payment policy from a quarterly payment schedule to a monthly payment schedule beginning with the distributions relating to the fourth quarter of 2013.

We do not have a legal obligation to pay distributions at any rate except as provided in the partnership agreement. Our distribution policy is consistent with the terms of our partnership agreement, which requires that we distribute all of our available cash quarterly. Under the partnership agreement, available cash is defined to generally mean, for each fiscal quarter, cash generated from our business in excess of the amount of reserves the General Partner determines is necessary or appropriate to provide for the conduct of the business, to comply with applicable law, any of its debt instruments or other agreements or to provide for future distributions to its unitholders for any one or more of the upcoming four quarters. The partnership agreement provides that any determination made by the General Partner in its capacity as general partner must be made in good faith and that any such determination will not be subject to any other standard imposed by the partnership agreement, the Delaware limited partnership statute or any other law, rule or regulation or at equity.

During the years ended December 31, 2013, 2012 and 2011, we paid cash distributions of approximately $183.6 million, $127.7 million and $97.6 million, respectively, to our common unitholders. The distributions that were paid to unitholders totaled $1.91, $1.83 and $1.69 per Common Unit, respectively. We also paid cash equivalent to the distribution paid to our unitholders of $3.3 million, $4.7 million and $5.1 million, respectively, to holders of outstanding RPUs and CPUs issued under our LTIP.

16. Noncontrolling interest

FASB Accounting Standards require that noncontrolling interests be classified as a component of equity and establish reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners.

In 2007, we acquired the limited partner interest 99% of BEPI. As such, we were fully consolidating the results of BEPI and were recognizing a noncontrolling interest representing the book value of BEPI’s general partner’s interests. Prior to April 1, 2012, BEPI’s general partner interest was held by PCEC, and PCEC held a 35% reversionary interest under the limited partnership agreement applicable to the East Coyote and Sawtelle Fields, which was expected to result in an increase in PCEC’s ownership and a corresponding decrease in our ownership in the properties during the second quarter of 2012. We and PCEC agreed to dissolve BEPI and liquidate the properties and assets of BEPI as of April 1, 2012. As a result of such agreement, PCEC’s ownership interest in both of these properties increased, and our ownership in the properties decreased from approximately 95% to 62%.

17. Unit Based Compensation Plans

FASB Accounting Standards establish requirements for charging compensation expenses based on fair value provisions. At December 31, 2013, the RPUs and the CPUs granted under LTIP as well as the outstanding Directors
RPUs discussed below were all classified as equity awards. These awards are being recognized as compensation expense on a straight line basis over the annual vesting periods as prescribed in the award agreements.

We recognized $20.0 million, $22.2 million and $22.0 million of compensation expense related to our various plans for the years ended December 31, 2013, 2012 and 2011, respectively.

**Restricted Phantom Units**

RPUs are phantom equity awards that, to the extent vested, represent the right to receive actual partnership units upon specified payment events. Certain of our employees including our executives are eligible to receive RPU awards. We believe that RPUs properly incentivize holders of these awards to grow stable distributions for our common unitholders. RPUs generally vest in three equal annual installments on each anniversary of the vesting commencement date of the award. In addition, each RPU is granted in tandem with a distribution equivalent right that will remain outstanding from the grant of the RPU until the earlier to occur of its forfeiture or the payment of the underlying unit, and which entitles the grantee to receive payment of amounts equal to distributions paid to each holder of an actual partnership unit during such period. RPUs that do not vest for any reason are forfeited upon a grantee’s termination of employment.

The fair value of the RPUs is determined based on the fair market value of our units on the date of grant. RPU awards were granted to BreitBurn Management employees during the years ended December 31, 2013, 2012 and 2011 as shown in the table below. We recorded compensation expense of $17.0 million, $17.4 million and $16.9 million in 2013, 2012 and 2011, respectively, related to the amortization of outstanding RPUs over their related vesting periods. As of December 31, 2013, there was $18.4 million of total unrecognized compensation cost remaining for the unvested RPUs. This amount is expected to be recognized over the next two years. The total fair value of units that vested during the years ended December 31, 2013, 2012 and 2011 was $17.2 million, $17.4 million, and $21.5 million, respectively.

The following table summarizes information about RPUs:

<table>
<thead>
<tr>
<th>Thousands, except per unit amounts</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Number of RPUs</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Outstanding, beginning of period</td>
<td>817</td>
<td>983</td>
<td>1,747</td>
</tr>
<tr>
<td>Granted</td>
<td>919</td>
<td>887</td>
<td>758</td>
</tr>
<tr>
<td>Exercised (a)</td>
<td>(833)</td>
<td>(1,005)</td>
<td>(1,505)</td>
</tr>
<tr>
<td>Canceled</td>
<td>(7)</td>
<td>(48)</td>
<td>(17)</td>
</tr>
<tr>
<td>Outstanding, end of period</td>
<td>896</td>
<td>817</td>
<td>983</td>
</tr>
<tr>
<td>Exercisable, end of period</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

(a) Includes 308, 394 and 521 units canceled at the time of distribution for income tax liability payments the Partnership made on behalf of the restricted unit grantees for years ended December 31, 2013, 2012 and 2011, respectively.

**Convertible Phantom Units**

On January 28, 2013, the Compensation and Governance Committee approved an amendment to the First Amended and Restated Partnership 2006 Long-Term Incentive Plan granting Participants CPU in tandem with a corresponding Performance Distribution Right (“PDR”) which will remain outstanding from the Grant Date until the earlier to occur of a Payment Date or the forfeiture of the CPU to which such PDR corresponds. Each CPU granted under this Agreement will be issued in tandem with a corresponding PDR, which will entitle the Participant to receive an amount determined by reference to Partnership distributions and which will be credited to the Participant in the form of additional CPUs equal to the product of (i) the aggregate per Unit distributions paid by the Partnership in respect of each quarter through which the PDR remains outstanding (provided that the PDR is outstanding as of the record date set by the Board of

F-34
Directors of the Company for such distribution) (including any extraordinary non-recurring distributions paid during a quarter), if any, times (ii) the number of common unit equivalents (“CUEs”) underlying the relevant CPU during such quarter, divided by the closing price of the Unit on the date on which such distribution is paid to Unitholders. All such PDRs will be credited to the Participant in the form of additional CPUs as of the date of payment of any such distribution based on the Fair Market Value of a Unit on such date. Each additional CPU which results from such crediting of PDRs granted hereunder will be subject to the same vesting, forfeiture, payment or distribution, adjustment and other provisions which apply to the underlying CPU to which such additional CPU relates. PDRs will not entitle the Participant to any amounts relating to distributions occurring after the earlier to occur of the applicable Payment Date or the Participant’s forfeiture of the CPU to which such PDR relates in accordance herewith. The CPUs will vest and the number of CUEs underlying such CPUs (if any) on the earliest to occur of (i) an applicable accelerated vesting date, and (ii) December 28, 2015, in each case subject to the Participant’s continued employment with the Partnership through any such date. CPUs that vest will represent the right to receive payment in the form of a number of Units equal to (i) the product of (A) the number of CPUs so vested, times (B) the number of CUEs underlying such CPUs on the applicable Vesting Date, minus (ii) the applicable number of PDR Equalization Units, if any (such number of Units, the “Resultant Units”). Unless and until a CPU vests, the Participant will have no right to payment of Units in respect of any such CPU. Prior to actual payment in respect of any vested CPU, such CPU will represent an unsecured obligation of the Partnership, payable (if at all) only from the general assets of the Partnership.

On January 28, 2013, 0.3 million units of CPUs (“2013 CPUs”) were granted at a price of $20.98 per Common Unit. We recorded compensation expense for the 2013 CPUs of $2.3 million in 2013. As of December 31, 2013, 0.4 million of unvested 2013 CPU units were outstanding and $4.7 million of total unrecognized compensation cost remained for the unvested 2013 CPUs. Such cost is expected to be recognized over the next three years.

In December 2007, seven executives, Halbert Washburn, Randall Breitenbach, Mark Pease, James Jackson, Gregory Brown, Thurmon Andress and Jackson Washburn, received 0.7 million units of CPUs (“2007 CPUs”) at a grant price of $30.29 per Common Unit. Each of the 2007 CPU awards had the vesting commencement date of January 1, 2008 and were to vest on the earliest to occur of (i) January 1, 2013, (ii) the date on which the aggregate amount of distributions paid to common unitholders for any four consecutive quarters during the term of the award is greater than or equal to $3.10 per Common Unit and (iii) upon the occurrence of the death or “disability” of the grantee or his or her termination without “cause” or for “good reason” (as defined in the holder’s employment agreement, if applicable).

On December 13, 2012, certain of our executive officers entered into an amendment with respect to their 2007 CPU grants, that provided that such grants could vest on December 28, 2012 instead of January 1, 2013. On vesting, each 2007 CPU converted into a number of CUEs equal to the number of Common Unit equivalents underlying the 2007 CPUs. The 2007 CPUs were converted to Common Units on a one-to-one basis and in total 0.7 million Common Units were issued. We recorded compensation expense for the 2007 CPUs of $4.1 million in 2012 and $4.1 million in 2011.

**Director Restricted Phantom Units**

Effective with the initial public offering until 2011, we also made grants of Restricted Phantom Units in the Partnership to the non-employee directors of our General Partner. Each phantom unit was accompanied by a distribution equivalent unit right entitling the holder to an additional number of phantom units with a value equal to the amount of distributions paid on each of our Common Units until settlement. Since 2010, the phantom units were paid in Common Units upon vesting, and the unit-settled awards are classified as equity. The estimated fair value associated with these phantom units is expensed in the statement of income over the vesting period. Since 2011, we have made grants of RPUs to the non-employee directors of our General Partner that are substantially similar to the ones granted to employees.

We recorded compensation expense for the director’s phantom units of approximately $0.7 million, $0.6 million and, $1.0 million in 2013, 2012 and 2011, respectively. As of December 31, 2013, there was $0.7 million of total unrecognized compensation cost for the unvested Director Performance Units and such cost is expected to be recognized over the next two years.

The following table summarizes information about the Director Restricted Phantom Units:
18. Retirement Plan

BreitBurn Management operates our assets and performs other administrative services for us such as accounting, corporate development, finance, land administration, legal and engineering. All of our employees, including our executives, are employees of BreitBurn Management. BreitBurn Management has a defined contribution retirement plan, which covers substantially all of its employees commencing on the first day of the month following the month of hire. The plan provides for BreitBurn Management to make regular contributions based on employee contributions as provided for in the plan agreement. Employees fully vest in BreitBurn Management’s contributions after five years of service. PCEC is charged for a portion of the matching contributions made by BreitBurn Management. For the years ended December 31, 2013, 2012 and 2011, we recognized expense related to matching contributions of $2.0 million, $1.3 million and $1.1 million, respectively.

19. Significant Customers

We sell oil, NGLs and natural gas primarily to large, established domestic refiners and utilities. For the years ended December 31, 2013, 2012 and 2011, we sold oil, NGL and natural gas production representing 10% or more of total revenue to the following purchasers:

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phillips 66 (a)</td>
<td>15%</td>
<td>16%</td>
<td>—%</td>
</tr>
<tr>
<td>Shell Trading</td>
<td>15%</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>Marathon Oil Corporation</td>
<td>10%</td>
<td>14%</td>
<td>15%</td>
</tr>
<tr>
<td>Plains Marketing &amp; Transportation LLC</td>
<td>9%</td>
<td>17%</td>
<td>16%</td>
</tr>
<tr>
<td>ConocoPhillips</td>
<td>5%</td>
<td>14%</td>
<td>30%</td>
</tr>
</tbody>
</table>

(a) During 2012, Phillips 66 and ConocoPhillips became two separate entities.

Our sales contracts are sold at market-sensitive or spot prices. Because commodity products are sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. As a result, the loss of any one purchaser would not have a long-term material adverse effect on our ability to sell our production.

20. Subsequent Events

On January 2, 2014, we announced a cash distribution to unitholders for the first monthly payment attributable to the fourth quarter of 2013 at the rate of $0.1642 per Common Unit, which was paid on January 16, 2014 to the record holders of common units at the close of business on January 13, 2014.

On January 30, 2014, we announced a cash distribution to unitholders for the second monthly payment attributable to the fourth quarter of 2013 at the rate of $0.1642 per Common Unit, which was paid on February 14, 2014 to the record holders of common units at the close of business on February 10, 2014.
On February 27, 2014, we announced a cash distribution to unitholders for the third monthly payment attributable to the fourth quarter of 2013 at the rate of $0.1642 per Common Unit, which will be paid on March 14, 2014 to the record holders of Common Units at the close of business on March 10, 2014.

In February 2014, we entered into the Eleventh Amendment to the Second Amended and Restated Credit Agreement that eliminated the Maximum Total Leverage Ratio (defined as the ratio of total debt to EBITDAX) and Maximum Senior Secured Leverage Ratio (defined as the ratio of senior secured indebtedness to EBITDAX) requirements and added a provision requiring us to maintain an Interest Coverage Ratio (defined as EBITDAX divided by Consolidated Interest Expense) for the four quarters ending on the last day of each quarter beginning with the fourth quarter of 2013 of no less than 2.50 to 1.00. The amendment also provides that we cannot incur senior unsecured debt in excess of our borrowing base in effect at the time of the issuance of such debt.

Supplemental Information

A. Oil, NGL and Natural Gas Activities (Unaudited)

Our proved reserves are estimated by third-party reservoir engineers and in accordance with SEC guidelines. We are reasonably certain that the estimated quantities will equal or exceed the estimates. Reserve estimates are expected to change as economic assumptions change and additional engineering and geoscience data becomes available. For reserve reporting purposes, we use unweighted average first-day-of-the-month pricing for the 12 calendar months prior to the end of the reporting period. Costs are held constant throughout the projected reserve life. While SEC guidelines permit a company to establish undeveloped reserves as proved with appropriate degrees of reasonable certainty established absent actual production tests and without artificially limiting such reserves to spacing units adjacent to a producing well, we have elected not to add such undeveloped reserves as proved.

Costs incurred

The following table summarizes our costs incurred for the past three years:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property acquisition costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proved</td>
<td>$971,968</td>
<td>$530,532</td>
<td>$341,602</td>
</tr>
<tr>
<td>Unproved</td>
<td>88,276</td>
<td>89,725</td>
<td>1,073</td>
</tr>
<tr>
<td>Pipelines and processing facilities</td>
<td>72,037</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Asset retirement costs</td>
<td>9,171</td>
<td>6,279</td>
<td>10,980</td>
</tr>
<tr>
<td>Development costs</td>
<td>294,822</td>
<td>152,820</td>
<td>75,635</td>
</tr>
<tr>
<td>Asset retirement costs - development</td>
<td>9,612</td>
<td>4,021</td>
<td>25,706</td>
</tr>
<tr>
<td>Total costs incurred</td>
<td>$1,445,886</td>
<td>$783,377</td>
<td>$454,996</td>
</tr>
</tbody>
</table>

Capitalized costs

The following table presents the aggregate capitalized costs subject to DD&A relating to oil and gas activities, and the aggregate related accumulated allowance:
The average DD&A rate per equivalent unit of production for the year ended December 31, 2013, excluding impairments and non-oil and gas related DD&A, was $19.18 per Boe. The average DD&A rate per equivalent unit of production for the year ended December 31, 2012, excluding impairments and non-oil and gas related DD&A, was $16.20 per Boe.

Results of operations for oil, NGL and natural gas producing activities

The results of operations from oil, NGL and natural gas producing activities below exclude G&A expenses, interest expenses and interest income:

| Thousands of dollars | December 31, |       |       |
|----------------------|-------------------|-------------------|
|                      | 2013       | 2012       | 2011       |
| Proved properties and related producing assets | $ 4,235,944 | $ 3,001,018 |
| Pipelines and processing facilities | 293,056 | 165,320 |
| Unproved properties | 289,640 | 197,608 |
| Accumulated depreciation, depletion and amortization | (911,249) | (655,607) |
| Net capitalized costs | $ 3,907,390 | $ 2,708,339 |

The following information summarizes our estimated proved reserves of oil, NGLs and natural gas and the present values thereof for the years ended December 31, 2013, 2012 and 2011. The following reserve information is based upon reports by Cawley, Gillespie & Associates, Inc. (“CGA”), Netherland, Sewell & Associates, Inc. (“NSAI”) and Schlumberger PetroTechnical Services (“SLB”), independent petroleum engineering firms. CGA provides reserve data for our Oklahoma properties. NSAI provides reserve data for our California, Wyoming and Florida properties, and SLB provides reserve data for our Michigan, Kentucky and Indiana properties. The estimates are prepared in accordance with SEC regulations. We only utilize large, widely known, highly regarded and reputable engineering consulting firms. Not only the firms, but the technical persons that sign and seal the reports are licensed and certify that they meet all professional requirements. Licensing requirements formally require mandatory continuing education and professional qualifications. They are independent petroleum engineers, geologists, geophysicists and petrophysicists.

Our reserve estimation process involves petroleum engineers and geoscientists. As part of this process, all reserves volumes are estimated using a forecast of production rates, current operating costs and projected capital expenditures. Reserves are based upon the unweighted average first-day-of-the-month prices for each year. Price differentials are then applied to adjust these prices to the expected realized field price. Specifics of each operating agreement are then used to estimate the net reserves. Production rate forecasts are derived by a number of methods, including decline curve analyses, volumetrics, material balance or computer simulation of the reservoir performance. Operating costs and capital costs are forecast using current costs combined with expectations of future costs for specific reservoirs. In many cases, activity-based cost models for a reservoir are utilized to project operating costs as production rates and the number of wells for production and injection vary.

Supplemental reserve information

(a) Excludes (gain) loss on sale of assets.
The technical person, employed by our General Partner, primarily responsible for overseeing preparation of the reserves estimates and the third party reserve reports is Mark L. Pease, the President and Chief Operating Officer of our General Partner. Mr. Pease received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines in 1979. Prior to joining our General Partner, Mr. Pease was Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation. Mr. Pease has over 30 years of experience working in various capacities in the energy industry, including acquisition analysis, reserve estimation, reservoir engineering and operations engineering. Mr. Pease consults with CGA, NSAI, and SLB during the reserve estimation process to review properties, assumptions and relevant data.

Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report included in this report as exhibits 99.1 are Mr. J. Carter Henson, Jr. and Mr. Mike K. Norton. Mr. Henson has been practicing consulting petroleum engineering at NSAI since 1989. Carter is a Licensed Professional Engineer in the State of Texas (License No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 22 years’ experience in the estimation and evaluation of reserves. Mr. Henson graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Norton has been practicing consulting petroleum geology at NSAI since 1989. Mr. Norton is a Licensed Petroleum Geologist in the State of Texas (License No. 441) and has over 34 years of practical experience in petroleum geosciences, with over 29 years’ experience in the estimation and evaluation of reserves. Mr. Norton graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Within SLB, the technical person primarily responsible for preparing the reserves estimates set forth in the SLB reserves report including in this report as exhibit 99.2 is Mr. Charles M. Boyer II, who has been with PetroTechnical Services (PTS) Division of SLB since 1998. Mr. Boyer attended The Pennsylvania State University and graduated with a Bachelor of Science Degree in Geological Sciences in 1976; Mr. Boyer is a Certified Petroleum Geologist of the American Association of Petroleum Geologists (Reg. No. 5733); Mr. Boyer is a Registered Professional Geologist in the Commonwealth of Pennsylvania (Reg. No. PG004509) and has in excess of 20 years’ experience in the conduct of evaluation and engineering studies relating to oil and gas interests.

Within CGA, the technical persons primarily responsible for preparing the estimates set forth in the CGA reserves report included in this report as exhibit 99.3 is Mr. Robert Ravnaas, who has been a Petroleum Consultant for CGA since 1983, and became President in 2011. Mr. Ravnaas has completed numerous field studies, reserve evaluations and reservoir simulation, waterflood design and monitoring, unit equity determinations and producing rate studies. He has testified before the Texas Railroad Commission in unification and field rules hearings. Prior to CGA Mr. Ravnaas worked as a Production Engineer for Amoco Production Company. Mr. Ravnaas received a B.S. with special honors in Chemical Engineering from the University of Colorado at Boulder, and a M.S. in Petroleum Engineering from the University of Texas at Austin. Mr. Ravnaas is a registered professional engineer in Texas, No. 61304, and a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, the American Association of Petroleum Geologists and the Society of Professional Well Log Analysts.

Management believes the reserve estimates presented herein, in accordance with generally accepted engineering and evaluation methods and procedures consistently applied, are reasonable. However, there are numerous uncertainties inherent in estimating quantities and values of the estimated proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and gas that cannot be measured in an exact manner and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of oil, NGLs and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil, NGL and natural gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the standardized measure of discounted net future cash flows shown below represents estimates only and should not be construed as the current market value of the estimated oil, NGL and
natural gas reserves attributable to our properties. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties included in the preceding year’s estimates. Such revisions reflect additional information from subsequent exploitation and development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Decreases in the prices of oil, NGLs, and natural gas and increases in operating expenses have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and revenues, profitability and cash flow.

The following table sets forth certain data pertaining to our estimated proved reserves, all of which are located within the United States, for the years ended December 31, 2013, 2012 and 2011.

<table>
<thead>
<tr>
<th>Net proved reserves</th>
<th>Total (MMBoe)</th>
<th>Oil (in MBbls)</th>
<th>NGLs (in MBbls)</th>
<th>Natural Gas (in MMcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>December 31, 2010</td>
<td>118,908</td>
<td>40,550</td>
<td>1,109</td>
<td>463,491</td>
</tr>
<tr>
<td>Revision of previous estimates</td>
<td>4,160</td>
<td>7,634</td>
<td>(47)</td>
<td>(20,563)</td>
</tr>
<tr>
<td>Purchase of previous reserves in-place</td>
<td>32,199</td>
<td>4,204</td>
<td>—</td>
<td>167,971</td>
</tr>
<tr>
<td>Extensions, discoveries and other</td>
<td>2,877</td>
<td>2,425</td>
<td>61</td>
<td>2,341</td>
</tr>
<tr>
<td>Production</td>
<td>(7,037)</td>
<td>(3,079)</td>
<td>(175)</td>
<td>(22,697)</td>
</tr>
<tr>
<td>December 31, 2011</td>
<td>151,106</td>
<td>51,735</td>
<td>948</td>
<td>590,543</td>
</tr>
<tr>
<td>Revision of previous estimates</td>
<td>(33,973)</td>
<td>(5,160)</td>
<td>794</td>
<td>(177,645)</td>
</tr>
<tr>
<td>Purchase of previous reserves in-place</td>
<td>33,696</td>
<td>23,861</td>
<td>3,716</td>
<td>36,712</td>
</tr>
<tr>
<td>Extensions, discoveries and other</td>
<td>6,887</td>
<td>6,671</td>
<td>61</td>
<td>932</td>
</tr>
<tr>
<td>Production</td>
<td>(8,318)</td>
<td>(3,514)</td>
<td>(138)</td>
<td>(27,997)</td>
</tr>
<tr>
<td>December 31, 2012</td>
<td>149,398</td>
<td>73,593</td>
<td>5,381</td>
<td>422,545</td>
</tr>
<tr>
<td>Revision of previous estimates</td>
<td>13,696</td>
<td>(3,312)</td>
<td>2,678</td>
<td>85,985</td>
</tr>
<tr>
<td>Purchase of previous reserves in-place</td>
<td>60,933</td>
<td>47,655</td>
<td>8,223</td>
<td>30,331</td>
</tr>
<tr>
<td>Sale of reserves in-place</td>
<td>(91)</td>
<td>(91)</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Extensions, discoveries and other</td>
<td>1,317</td>
<td>1,014</td>
<td>48</td>
<td>1,527</td>
</tr>
<tr>
<td>Production</td>
<td>(10,983)</td>
<td>(5,651)</td>
<td>(640)</td>
<td>(28,156)</td>
</tr>
<tr>
<td>December 31, 2013</td>
<td>214,271</td>
<td>113,208</td>
<td>15,690</td>
<td>512,233</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Proved developed reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>December 31, 2011</td>
</tr>
<tr>
<td>December 31, 2012</td>
</tr>
<tr>
<td>December 31, 2013</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Proved undeveloped reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>December 31, 2011</td>
</tr>
<tr>
<td>December 31, 2012</td>
</tr>
<tr>
<td>December 31, 2013</td>
</tr>
</tbody>
</table>

Revisions of Previous Estimates

In 2013, we had positive revisions of 13.7 MMBoe, primarily related to an increase in oil and natural gas prices and 1.3 MMBoe of extensions and discoveries. Unweighted average first-day-of-the-month oil and natural gas prices used to determine our total estimated proved reserves as of December 31, 2013 were $96.94 per Bbl of oil and $3.67 per MMbtu.
of gas, compared to $94.71 per Bbl of oil and $2.76 per MMBtu of gas in 2012. In 2012, we had negative revisions of 34.0 MMBoe, primarily related to a decrease in natural gas prices offset by 6.9 MMBoe of extensions and discoveries.

Unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2011 were $95.97 per Bbl of oil, and $4.12 per MMBtu of gas. In 2011, we had positive revisions of 4.1 MMBoe, primarily related to an increase in oil and NGL prices offset by a decrease in natural gas prices and 2.9 MMBoe of extensions and discoveries.

Conversion of Proved Undeveloped Reserves

During the years ended December 31, 2013, 2012 and 2011, we incurred $160.1 million, $21.6 million and $15.4 million in capital expenditures, respectively, and drilled 122 wells, 20 wells and 28 wells, respectively, related to the conversion of proved undeveloped to proved developed reserves. During the years ended December 31, 2013, 2012 and 2011, we converted 9.7 MMBoe, 2.3 MMBoe and 1.0 MMBoe, respectively, from proved undeveloped to proved developed reserves. As of December 31, 2013, we had no proved undeveloped reserves that have remained undeveloped for more than five years. The increase in proved undeveloped reserves during the year ended December 31, 2013 was primarily due to the Oklahoma Panhandle Acquisitions and the 2013 Permian Basin Acquisitions, which added 13.7 MMBoe and 9.5 MMBoe of proved undeveloped reserves, respectively, partially offset by economic revisions and the conversion of proved undeveloped to proved developed reserves. The increase in proved undeveloped reserves during the year ended December 31, 2012 was primarily due to the Permian Basin Acquisitions, the NiMin Acquisition and the AEO Acquisition, which added 12.9 MMBoe, 2.4 MMBoe and 1.4 MMBoe of proved undeveloped reserves, respectively, partially offset by economic revisions and the conversion of proved undeveloped to proved developed reserves. The increase in proved undeveloped reserves during the year ended December 31, 2011 was primarily due to the acquisition of 10.3 MMBoe and 1.9 MMBoe of proved undeveloped reserves in the Cabot Acquisition and the Greasewood Acquisition, respectively.

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves as of December 31, 2013, 2012 and 2011 is presented below:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td>Future cash inflows</td>
<td>$13,187,507</td>
</tr>
<tr>
<td>Future development costs</td>
<td>(962,517)</td>
</tr>
<tr>
<td>Future production expense</td>
<td>(5,703,997)</td>
</tr>
<tr>
<td>Future net cash flows</td>
<td>6,520,993</td>
</tr>
<tr>
<td>Discounted at 10% per year</td>
<td>(3,295,145)</td>
</tr>
<tr>
<td>Standardized measure of discounted future net cash flows</td>
<td>$3,225,848</td>
</tr>
</tbody>
</table>

The standardized measure of discounted future net cash flows discounted at 10% from production of proved reserves was developed as follows:

1. An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.
2. In accordance with SEC guidelines, the reserve engineers’ estimates of future net revenues from our estimated proved properties and the present value thereof are made using unweighted average first-day-of-the-month oil and gas sales prices and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. We have entered into various derivative instruments to fix or limit the prices relating to a portion of our oil and gas production. Derivative instruments in effect at December 31, 2013 and 2012 are discussed in Note 4. Such derivative instruments are not reflected in the reserve reports. Representative unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2013 were $96.94 per Bbl of
oil and $3.67 per MMBtu of gas, compared to $94.71 per Bbl of oil and $2.76 per MMBtu of gas in 2012. Unweighted average first-
day-of-the-month market prices for the reserve reports for the year ended December 31, 2011 were $95.97 per Bbl of oil and $4.12 per
MMBtu of gas.
3. The future gross revenue streams were reduced by estimated future operating costs (including production and ad valorem taxes) and
future development and abandonment costs, all of which were based on current costs. Future net cash flows assume no future income
tax expense as we are essentially a non-taxable entity except for four tax-paying corporations whose future income tax liabilities on a
discounted basis are insignificant.

The principal sources of changes in the standardized measure of the future net cash flows for the years ended December 31, 2013, 2012 and
2011 are presented below:

<table>
<thead>
<tr>
<th>Thousands of dollars</th>
<th>Year Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td>Beginning balance</td>
<td>$ 1,989,895</td>
</tr>
<tr>
<td>Sales, net of production expense</td>
<td>(397,843)</td>
</tr>
<tr>
<td>Net change in sales and transfer prices, net of production expense</td>
<td>259,186</td>
</tr>
<tr>
<td>Previously estimated development costs incurred during year</td>
<td>176,253</td>
</tr>
<tr>
<td>Changes in estimated future development costs</td>
<td>(140,105)</td>
</tr>
<tr>
<td>Extensions, discoveries and improved recovery, net of costs</td>
<td>28,445</td>
</tr>
<tr>
<td>Purchase of reserves in place</td>
<td>1,044,004</td>
</tr>
<tr>
<td>Sale of reserves in-place</td>
<td>(2,694)</td>
</tr>
<tr>
<td>Revision of quantity estimates and timing of estimated production</td>
<td>69,718</td>
</tr>
<tr>
<td>Accretion of discount</td>
<td>198,989</td>
</tr>
<tr>
<td>Ending balance</td>
<td>$ 3,225,848</td>
</tr>
</tbody>
</table>

F-42
### B. Quarterly Financial Data (Unaudited)

#### Year ended December 31, 2013

<table>
<thead>
<tr>
<th></th>
<th>First Quarter</th>
<th>Second Quarter</th>
<th>Third Quarter</th>
<th>Fourth Quarter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil, NGL and natural gas sales</td>
<td>$120,362</td>
<td>$149,286</td>
<td>$197,413</td>
<td>$193,604</td>
</tr>
<tr>
<td>Gain (loss) on derivative instruments, net</td>
<td>(24,176)</td>
<td>66,993</td>
<td>(54,765)</td>
<td>(17,234)</td>
</tr>
<tr>
<td>Other revenue, net</td>
<td>758</td>
<td>702</td>
<td>737</td>
<td>978</td>
</tr>
<tr>
<td>Total revenue</td>
<td>96,944</td>
<td>216,981</td>
<td>143,385</td>
<td>177,348</td>
</tr>
<tr>
<td>Operating income (loss)</td>
<td>(17,853)</td>
<td>95,419</td>
<td>(1,435)</td>
<td>(31,855)</td>
</tr>
<tr>
<td>Net income (loss) (a)</td>
<td>$ (36,300)</td>
<td>$ 76,432</td>
<td>$ (25,011)</td>
<td>$ (58,792)</td>
</tr>
<tr>
<td>Basic net income (loss) per limited partner unit (b)</td>
<td>$ (0.38)</td>
<td>$ 0.75</td>
<td>$ (0.25)</td>
<td>$ (0.52)</td>
</tr>
<tr>
<td>Diluted net income (loss) per limited partner unit (b)</td>
<td>$ (0.38)</td>
<td>$ 0.75</td>
<td>$ (0.25)</td>
<td>$ (0.52)</td>
</tr>
</tbody>
</table>

(a) Fourth quarter 2013, we recognized and recorded an impairment charge of $54.4 million due to reserve adjustments due to lower performance and a decrease in expected future commodity prices. See Note 8 for details on impairments.

(b) Due to changes in the number of weighted average common units outstanding that may occur each quarter, the sum of the earnings per unit amounts for the quarters may not be additive to the full year earnings per unit amount.

#### Year ended December 31, 2012

<table>
<thead>
<tr>
<th></th>
<th>First Quarter</th>
<th>Second Quarter</th>
<th>Third Quarter</th>
<th>Fourth Quarter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil, NGL and natural gas sales</td>
<td>$94,007</td>
<td>$94,981</td>
<td>$111,700</td>
<td>$113,179</td>
</tr>
<tr>
<td>Gain (loss) on derivative instruments, net</td>
<td>(36,005)</td>
<td>107,288</td>
<td>(69,418)</td>
<td>3,715</td>
</tr>
<tr>
<td>Other revenue, net</td>
<td>1,145</td>
<td>907</td>
<td>796</td>
<td>700</td>
</tr>
<tr>
<td>Total revenue</td>
<td>59,147</td>
<td>203,176</td>
<td>43,078</td>
<td>117,594</td>
</tr>
<tr>
<td>Operating income (loss)</td>
<td>(36,194)</td>
<td>107,810</td>
<td>(58,029)</td>
<td>8,113</td>
</tr>
<tr>
<td>Net income (loss) (a)</td>
<td>$ (49,925)</td>
<td>$ 92,523</td>
<td>$ (73,003)</td>
<td>$ (10,334)</td>
</tr>
<tr>
<td>Basic net income (loss) per limited partner unit (b)</td>
<td>$ (0.76)</td>
<td>$ 1.29</td>
<td>$ (1.00)</td>
<td>$ (0.13)</td>
</tr>
<tr>
<td>Diluted net income (loss) per limited partner unit (b)</td>
<td>$ (0.76)</td>
<td>$ 1.29</td>
<td>$ (1.00)</td>
<td>$ (0.13)</td>
</tr>
</tbody>
</table>

(a) First quarter and Second quarter 2012, we recognized and recorded impairment charges of $9.0 million and $3.3 million, respectively, due to a decrease in future natural gas prices and reserve adjustments due to lower performance. See Note 8 for details on impairments.

(b) Due to changes in the number of weighted average common units outstanding that may occur each quarter, the sum of the earnings per unit amounts for the quarters may not be additive to the full year earnings per unit amount.
<table>
<thead>
<tr>
<th>NUMBER</th>
<th>DOCUMENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.1</td>
<td>Certificate of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to Amendment No. 1 to Form S-1 (File No. 333-134049) filed on July 13, 2006).</td>
</tr>
<tr>
<td>3.2</td>
<td>First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 16, 2006).</td>
</tr>
<tr>
<td>3.3</td>
<td>Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).</td>
</tr>
<tr>
<td>3.4</td>
<td>Amendment No. 2 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed April 9, 2009).</td>
</tr>
<tr>
<td>3.5</td>
<td>Amendment No. 3 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed September 1, 2009).</td>
</tr>
<tr>
<td>3.6</td>
<td>Amendment No. 4 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on April 9, 2010).</td>
</tr>
<tr>
<td>3.7</td>
<td>Amendment No. 5 to the First Amended and Restated Agreement of Limited Partnership of BreitBurn Energy Partners L.P. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on April 9, 2010).</td>
</tr>
<tr>
<td>3.8</td>
<td>Fourth Amended and Restated Limited Liability Company Agreement of BreitBurn GP, LLC dated as of April 5, 2010 (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K (File No. 001-33055) filed on April 9, 2011).</td>
</tr>
<tr>
<td>3.9</td>
<td>Amendment No. 1 to the Fourth Amended and Restated Limited Liability Company Agreement of BreitBurn GP, LLC dated as of December 30, 2010 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-33055) filed on January 6, 2011).</td>
</tr>
<tr>
<td>4.1</td>
<td>Indenture, dated as of October 6, 2010, by and among BreitBurn Energy Partners L.P., BreitBurn Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 7, 2010).</td>
</tr>
<tr>
<td>4.4</td>
<td>Registration Rights Agreement, dated as of September 27, 2012, by and among BreitBurn Energy Partners L.P., BreitBurn Finance Corporation, the Guarantors named therein and Wells Fargo Securities, LLC, as representative of the Initial Purchasers named therein (incorporated herein by reference to Exhibit 4.2 to the Current Report on Form 8-K (File No. 001-33055) filed on September 28, 2012).</td>
</tr>
<tr>
<td>4.5</td>
<td>First Supplemental Indenture, dated as of August 8, 2013, by and among BreitBurn Energy Partners L.P., BreitBurn Finance Corporation, the Guarantors named therein and U.S. Bank National Association, to the Indenture, dated as of October 6, 2010 (incorporated herein by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-33055) filed on November 22, 2013).</td>
</tr>
</tbody>
</table>

10.2 Amendment No. 1 to the Operations and Proceeds Agreement, relating to the Dominguez Field and dated October 10, 2006 entered into on June 17, 2008 by and between BreitBurn Energy Company L.P. and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.6 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).

10.3 Amendment No. 1 to the Surface Operating Agreement dated October 10, 2006 entered into on June 17, 2008 by and between BreitBurn Energy Company L.P. and its predecessor BreitBurn Energy Corporation and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.7 to the Current Report on Form 8-K (File No. 001-33055) filed on June 23, 2008).

10.4† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreement (Employment Agreement Form) (incorporated herein by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the period ended June 30, 2008 (File No. 001-33055) and filed on August 11, 2008).

10.5† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreement (Non-Employment Agreement Form) (incorporated herein by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the period ended June 30, 2008 and (File No. 001-33055) filed on August 11, 2008).


10.7 Indemnity Agreement between BreitBurn Energy Partners L.P., BreitBurn GP, LLC and Halbert S. Washburn, together with a schedule identifying other substantially identical agreements between BreitBurn Energy Partners L.P., BreitBurn GP, LLC and each of its executive officers and non-employee directors identified on the schedule (incorporated herein by reference to Exhibit 10.1 to the Current Report on form 8-K (File No. 001-33055) filed on November 4, 2009).

10.8† First Amendment to the BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreements (incorporated herein by reference to Exhibit 10.2 to the Current Report on form 8-K (File No. 001-33055) filed on November 4, 2009).

10.9† First Amended and Restated BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan effective as of October 29, 2009 (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the period ended September 30, 2009 (File No. 001-33055) filed on November 6, 2009).

10.10† First Amendment to the First Amended and Restated BreitBurn Energy Partners L.P. 2006 Long Term Incentive Plan (incorporated herein by reference to Exhibit 10.2 to the Form S-8 Registration Statement (File No. 333-181526) filed on May 18, 2012).

10.11† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Executive Form) (incorporated herein by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).


10.13† Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Director Form) (incorporated herein by reference to Exhibit 10.23 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).

10.14† Form of Second Amendment to the BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreements (incorporated herein by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).

10.15† Form of Third Amendment to the BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreements (incorporated herein by reference to Exhibit 10.25 to the Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0001-33055) filed on March 9, 2011).


First Amendment dated September 17, 2010 to the Second Amended and Restated Credit Agreement dated May 7, 2010, by and among BreitBurn Operating L.P., as borrower, BreitBurn Energy Partners L.P., as parent guarantor, and Wells Fargo Bank, N.A., as administrative agent (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on September 23, 2010).

Second Amendment to the Second Amended and Restated Credit Agreement dated May 9, 2011 (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-33055) filed on May 10, 2011).

Third Amendment to the Second Amended and Restated Credit Agreement dated August 3, 2011 (incorporated herein by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (File No. 001-33055) filed on August 8, 2011).

Fourth Amendment to the Second Amended and Restated Credit Agreement dated October 5, 2011 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 7, 2011).

Eighth Amendment to the Second Amended and Restated Credit Agreement dated May 22, 2013 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on July 18, 2013).

Ninth Amendment to the Second Amended and Restated Credit Agreement dated July 15, 2013 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on July 18, 2013).

Tenth Amendment to the Second Amended and Restated Credit Agreement dated November 6, 2013.

Eleventh Amendment to the Second Amended and Restated Credit Agreement dated February 21, 2014.

<table>
<thead>
<tr>
<th>NUMBER</th>
<th>DOCUMENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.37</td>
<td>Fifth Amendment to the Second Amended and Restated Credit Agreement, dated as of May 25, 2012 (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on June 29, 2012).</td>
</tr>
<tr>
<td>10.38</td>
<td>Sixth Amendment to the Second Amended and Restated Credit Agreement, dated as of October 11, 2012 (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on October 16, 2012).</td>
</tr>
<tr>
<td>10.44</td>
<td>Purchase and Sale Agreement, dated December 11, 2012, between Lynden USA Inc. and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on December 12, 2012).</td>
</tr>
<tr>
<td>10.45†</td>
<td>Form of First Amendment to BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Director Form) (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on December 14, 2012).</td>
</tr>
<tr>
<td>NUMBER</td>
<td>DOCUMENT</td>
</tr>
<tr>
<td>--------</td>
<td>----------</td>
</tr>
<tr>
<td>10.46†</td>
<td>Form of Fourth Amendment to BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Convertible Phantom Unit Agreement (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33055) filed on December 14, 2012).</td>
</tr>
<tr>
<td>10.48*†</td>
<td>Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Employment Agreement Form) for 2014 grants.</td>
</tr>
<tr>
<td>10.49*†</td>
<td>Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (For Directors) for 2014 grants.</td>
</tr>
<tr>
<td>10.50*†</td>
<td>Form of BreitBurn Energy Partners L.P. 2006 Long-Term Incentive Plan Restricted Phantom Unit Agreement (Deferred Payment Award) for 2014 grants.</td>
</tr>
<tr>
<td>10.51</td>
<td>Purchase and Sale Agreement dated June 22, 2013, by and between Whiting Oil and Gas Corporation and BreitBurn Operating L.P. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-33055) filed on June 25, 2013).</td>
</tr>
<tr>
<td>10.53</td>
<td>Seventh Amendment to the Second Amended and Restated Credit Agreement dated February 26, 2013 (incorporated herein by reference to Exhibit 10.1 to the Annual Report on Form 10-K (File No. 001-33055) filed on February 28, 2013).</td>
</tr>
<tr>
<td>21.1*</td>
<td>List of subsidiaries of BreitBurn Energy Partners L.P.</td>
</tr>
<tr>
<td>23.1*</td>
<td>Consent of PricewaterhouseCoopers LLP.</td>
</tr>
<tr>
<td>23.2*</td>
<td>Consent of Netherland, Sewell &amp; Associates, Inc.</td>
</tr>
<tr>
<td>23.3*</td>
<td>Consent of Schlumberger PetroTechnical Services.</td>
</tr>
<tr>
<td>23.4*</td>
<td>Consent of Cawley, Gillespie &amp; Associates, Inc.</td>
</tr>
<tr>
<td>32.1**</td>
<td>Certification of Registrant’s Chief Executive Officer pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002.</td>
</tr>
<tr>
<td>32.2**</td>
<td>Certification of Registrant’s Chief Financial Officer pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002.</td>
</tr>
<tr>
<td>99.2*</td>
<td>Schlumberger PetroTechnical Services reserve report.</td>
</tr>
<tr>
<td>99.3*</td>
<td>Cawley, Gillespie &amp; Associates, Inc. reserve report.</td>
</tr>
<tr>
<td>101.INS*</td>
<td>XBRL Instance Document.</td>
</tr>
<tr>
<td>101.CAL*</td>
<td>XBRL Taxonomy Extension Calculation Linkbase Document.</td>
</tr>
<tr>
<td>101.DEF*</td>
<td>XBRL Taxonomy Extension Definition Linkbase Document.</td>
</tr>
<tr>
<td>101.LAB*</td>
<td>XBRL Taxonomy Extension Label Linkbase Document.</td>
</tr>
<tr>
<td>101.PRE*</td>
<td>XBRL Taxonomy Extension Presentation Linkbase Document.</td>
</tr>
</tbody>
</table>
* Filed herewith.
** Furnished herewith.
† Management contract or compensatory plan or arrangement.
TENTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT

THIS TENTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT (hereinafter called this “Amendment”) is dated effective as of November 6, 2013, by and among BREITBURN OPERATING L.P., a Delaware limited partnership (the “Company”), BREITBURN ENERGY PARTNERS L.P., as Parent Guarantor (the “Parent”), BreitBurn GP, LLC (the “Parent GP”), BreitBurn Operating GP, LLC (the “General Partner”), the Subsidiaries of the Parent and/or the Company, as guarantors (the “Subsidiary Guarantors”), and together with the Parent, the Parent GP, and the General Partner, the “Guarantors”), EACH LENDER SIGNATORY HERETO, and WELLS FARGO BANK, NATIONALASSOCIATION, as administrative agent for the Lenders (in such capacity, together with its successors in such capacity “Administrative Agent”). Capitalized terms used in this Amendment, and not otherwise defined in this Amendment, have the meanings assigned thereto in the Credit Agreement defined below.

WITNESSETH:

WHEREAS, the Company, the Guarantors, Administrative Agent, Issuing Lender and the lenders from time to time party thereto (the “Lenders”) are parties to that certain Second Amended and Restated Credit Agreement dated as of May 7, 2010, as amended by the following: that certain First Amendment to Second Amended and Restated Credit Agreement and Consent and First Amendment to Security Agreement dated as of September 17, 2010, Second Amendment dated as of May 9, 2011, Third Amendment dated as of August 3, 2011, Fourth Amendment dated as of October 5, 2011, Fifth Amendment dated as of May 25, 2012, Sixth Amendment dated as of October 11, 2012, Seventh Amendment dated as of February 26, 2013, Eighth Amendment to Second Amended and Restated Credit Agreement dated as of May 22, 2013 and Ninth Amendment to Second Amended and Restated Credit Agreement dated as of July 15, 2013 (as further amended, modified or restated from time to time, the “Credit Agreement”), whereby upon the terms and conditions therein stated the Lenders have agreed to make certain loans to the Company upon the terms and conditions set forth therein;

WHEREAS, the Company has requested that the Lenders amend the Credit Agreement as set forth below; and

WHEREAS, subject to the terms hereof, the undersigned Lenders are willing to agree to the amendments to the Credit Agreement as set forth herein.

NOW, THEREFORE, for and in consideration of the mutual covenants and agreements herein contained, the parties to this Amendment hereby agree as follows:

SECTION 1. Amendments to Credit Agreement. Effective as of the Amendment Effective Date, Section 8.09 of the Credit Agreement is hereby amended and restated in its entirety as follows:

“8.09 Restricted Payments. No Loan Party shall, or permit any of its Subsidiaries to, purchase, redeem or otherwise acquire for value any membership interests, partnership interests, capital accounts, shares of its capital stock or any warrants, rights or options to acquire such membership interest, partnership interest or shares, now or hereafter outstanding from its members, partners or stockholders or declare or pay any distribution, dividend or return capital to its members, partners or stockholders, or make any distribution of assets in cash or in kind to its members, partners or stockholders (collectively “Restricted Payments”); except (a) Parent may declare and pay dividends with respect to its Equity payable solely in additional shares of its Equity, (b) Subsidiaries of the Company may declare and pay dividends ratably with respect to their Equity, (c) the Company may declare and pay dividends to Parent, and (d) Parent may declare and pay to its Equity owners periodic cash dividends of Available Cash or otherwise purchase, redeem or acquire for value any membership interests, partnership interests, capital accounts, shares of its capital stock or any warrants, rights or options to acquire such membership interest, partnership interest or shares from its members, partners or stockholders in accordance with its partnership agreement, so long as no Event of Default exists or would result therefrom, and after giving effect to such Restricted Payment, the Loan Parties exhibit pro-forma compliance with all terms and conditions of this Agreement. By making a Restricted Payment pursuant to clause (d) above, Parent represents and warrants to Administrative Agent and the Lenders that the conditions for making such Restricted Payment have been satisfied.”

SECTION 2. Guarantor Confirmation.

(a) The Guarantors hereby consent and agree to this Amendment and each of the transactions contemplated hereby.
The Company and each Guarantor ratifies and confirms the debts, duties, obligations, liabilities, rights, titles, pledges, grants of security interests, liens, powers, and privileges existing by virtue of the Loan Documents to which it is a party.

The Company and each Guarantor agrees that the guarantees, pledges, grants of security interests and other obligations, and the terms of each of the Security Agreements and Guaranties to which it is a party, are not impaired, released, diminished or reduced in any manner whatsoever and shall continue to be in full force and effect and shall continue to secure all Obligations.

The Company and each Guarantor acknowledges and agrees that all terms, provisions, and conditions of the Loan Documents to which it is a party (as amended by this Amendment) shall continue in full force and effect and shall remain enforceable and binding in accordance with their respective terms.

SECTION 3. Conditions of Effectiveness. This Amendment and the amendments hereunder shall become effective as of the date first set forth above (the “Amendment Effective Date”), provided that the following conditions shall have been satisfied:

(a) Amendment. The Administrative Agent shall have received a counterpart of this Amendment which shall have been executed by the Administrative Agent, the Issuing Lender, each of the Lenders, the Company, and the Guarantors (which may be by telecopy or PDF transmission).

(b) No Default; Representations and Warranties. As of the Amendment Effective Date:

(i) the representations and warranties of the Company and the Guarantors in Article VI of the Credit Agreement and in the other Loan Documents as amended hereby shall be true and correct in all material respects (except to the extent such representations and warranties expressly refer to an earlier date, in which case they shall be true and correct as of such earlier date, and except that the representations and warranties contained in clauses (a) and (b) of Section 6.14 of the Credit Agreement shall be deemed to refer to the most recent statements furnished pursuant to clauses (a) and (b), respectively, of Section 7.01 of the Credit Agreement);

(ii) no Default or Event of Default shall exist; and

(iii) since December 31, 2012, there shall have been no event, development or circumstance that has had or could reasonably be expected to have a Material Adverse Effect.

(c) Payment of Fees. The Company shall have paid all accrued and unpaid fees, costs and expenses owed pursuant to this Amendment to the extent then due and payable on the Amendment Effective Date.

(d) Additional Documents. Such other documents, in form and substance satisfactory to Administrative Agent, as the Administrative Agent may reasonably request.

SECTION 4. Representations and Warranties. Each of the Company and the Parent represents and warrants to Administrative Agent and the Lenders, with full knowledge that such Persons are relying on the following representations and warranties in executing this Amendment, as follows:

(a) It has the organizational power and authority to execute, deliver and perform this Amendment, and all organizational action on the part of it requisite for the due execution, delivery and performance of this Amendment has been duly and effectively taken.

(b) The Credit Agreement, as amended by this Amendment, the Loan Documents and each and every other document executed and delivered to the Administrative Agent and the Lenders in connection with this Amendment to which it is a party constitute the legal, valid and binding obligations of it, to the extent it is a party thereto, enforceable against such Person in accordance with their respective terms except as enforceability may be limited by applicable bankruptcy, insolvency, or similar laws affecting the enforcement of creditors’ rights generally or by equitable principles relating to enforceability.

(c) This Amendment does not and will not violate any provisions of any of the Organization Documents of the Company.

(d) No approval, consent, exemption, authorization, or other action by, or notice to, or filing with, any Governmental Authority is necessary or required in connection with the execution, delivery or performance by, or enforcement against, any Loan
(e) After giving effect to this Amendment, no Default or Event of Default will exist, and all of the representations and warranties contained in the Credit Agreement and in the other Loan Documents are true and correct in all material respects on and as of this date (except to the extent such representations and warranties expressly refer to an earlier date, in which case they shall be true and correct as of such earlier date).

SECTION 5. Reference to and Effect on the Credit Agreement.

(a) Upon the effectiveness hereof, on and after the date hereof, each reference in the Credit Agreement to “this Agreement,” “hereunder,” “hereof,” “herein,” or words of like import, shall mean and be a reference to the Credit Agreement as amended hereby.

(b) Except as specifically amended by this Amendment, the Credit Agreement shall remain in full force and effect and is hereby ratified and confirmed.

SECTION 6. Extent of Amendments. Except as otherwise expressly provided herein, the Credit Agreement and the other Loan Documents are not amended, modified or affected by this Amendment. Each of the Company and the Parent hereby ratifies and confirms that (i) except as expressly amended hereby, all of the terms, conditions, covenants, representations, warranties and all other provisions of the Credit Agreement remain in full force and effect, (ii) each of the other Loan Documents are and remain in full force and effect in accordance with their respective terms, and (iii) the Collateral and the Liens on the Collateral securing the Obligations are unimpaired by this Amendment and remain in full force and effect.

SECTION 7. Loan Documents. The Loan Documents, as such may be amended in accordance herewith, are and remain legal, valid and binding obligations of the parties thereto, enforceable in accordance with their respective terms. This Amendment is a Loan Document.

SECTION 8. Claims. As additional consideration to the execution, delivery, and performance of this Amendment by the parties hereto and to induce Administrative Agent and Lenders to enter into this Amendment, each of the Company and the Parent represents and warrants that, as of the date hereof, it does not know of any defenses, counterclaims or rights of setoff to the payment of any Indebtedness of the Company or the Parent to Administrative Agent, Issuing Lender or any Lender.

SECTION 9. Execution and Counterparts. This Amendment may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of this Amendment by facsimile or pdf shall be equally as effective as delivery of a manually executed counterpart.

SECTION 10. Governing Law. This Amendment shall be governed by and construed in accordance with the laws of the State of New York and applicable federal laws of the United States of America.

SECTION 11. Headings. Section headings in this Amendment are included herein for convenience and reference only and shall not constitute a part of this Amendment for any other purpose.

SECTION 12. NO ORAL AGREEMENTS. THE RIGHTS AND OBLIGATIONS OF EACH OF THE PARTIES TO THE LOAN DOCUMENTS SHALL BE DETERMINED SOLELY FROM WRITTEN AGREEMENTS, DOCUMENTS, AND INSTRUMENTS, AND ANY PRIOR ORAL AGREEMENTS BETWEEN SUCH PARTIES ARE SUPERSEDED BY AND MERGED INTO SUCH WRITINGS. THIS AMENDMENT AND THE OTHER WRITTEN LOAN DOCUMENTS EXECUTED BY THE COMPANY, THE GUARANTORS, ADMINISTRATIVE AGENT, ISSUING LENDER AND/OR LENDERS REPRESENT THE FINAL AGREEMENT BETWEEN SUCH PARTIES, AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS BY SUCH PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN SUCH PARTIES.

SECTION 13. No Waiver. Each of the Company and the Parent hereby agrees that no Event of Default and no Default has been waived or remedied by the execution of this Amendment by the Administrative Agent or any Lender. Nothing contained in this Amendment nor any past indulgence by the Administrative Agent, Issuing Lender or any Lender, nor any other action or inaction on behalf of the Administrative Agent, Issuing Lender or any Lender, (i) shall constitute or be deemed to constitute a waiver of any Defaults or Events of Default which may exist under the Credit Agreement or the other Loan Documents, or (ii) shall constitute or be deemed to constitute an election of remedies by the Administrative Agent, Issuing Lender or any Lender, or a waiver of any of the rights or remedies of the Administrative Agent, Issuing Lender or any Lender provided in the Credit
IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered by their proper and duly authorized officers as of the day and year first above written.

**LOAN PARTIES:**

BREITBURN OPERATING L.P., a Delaware limited partnership
   By: BreitBurn Operating GP, LLC, its general partner
BREITBURN ENERGY PARTNERS L.P., a Delaware limited partnership
   By: BreitBurn GP, LLC, its general partner
BREITBURN OPERATING GP, LLC, a Delaware limited partnership
BREITBURN FINANCE CORPORATION, a Delaware corporation
BREITBURN MANAGEMENT COMPANY, LLC, a Delaware limited liability company
ALAMITOS COMPANY, a California corporation
BREITBURN FLORIDA LLC, a Delaware limited liability company
   By: BreitBurn Operating L.P., its sole member
   By: BreitBurn Operating GP, LLC, its general partner
BREITBURN FULTON LLC, a Delaware limited liability company
BEAVER CREEK PIPELINE, L.L.C., a Michigan limited liability company
GTG PIPELINE LLC, a Virginia limited liability company
MERCURY MICHIGAN COMPANY, LLC, a Michigan limited liability company
TERRA ENERGY COMPANY LLC, a Michigan limited liability company
TERRA PIPELINE COMPANY LLC, a Michigan limited liability company
PHOENIX PRODUCTION COMPANY, a Wyoming corporation
PREVENTIVE MAINTENANCE SERVICES LLC, a Colorado limited liability company
BREITBURN TRANSPETCO GP LLC, a Delaware limited liability company
   By: BreitBurn Operating L.P., its sole member
   By: BreitBurn Operating GP, LLC, its general partner
BREITBURN TRANSPETCO LP LLC, a Delaware limited liability company
   By: BreitBurn Operating L.P., its sole member
   By: BreitBurn Operating GP, LLC, its general partner
TRANSPETCO PIPELINE COMPANY, L.P., a Delaware limited partnership
   By: BreitBurn Operating L.P., on behalf of itself and as the sole member of BreitBurn Transpetco GP LLC, each a general partner
   By: BreitBurn Operating GP, LLC, its general partner
BREITBURN OKLAHOMA LLC, a Delaware limited liability company
   By: BreitBurn Operating L.P., its sole member
   By: BreitBurn Operating GP, LLC, its general partner

By: /s/ James G. Jackson
James G. Jackson
Chief Financial Officer
PARENT GP:

BREITBURN GP, LLC, 
a Delaware limited partnership

By: /s/ James G. Jackson
James G. Jackson
Chief Financial Officer

WELLS FARGO BANK, NATIONAL ASSOCIATION as Administrative Agent, Issuing Lender, Swing Line Lender and a Lender

By: /s/ Matt Turner
Matt Turner
Vice President

THE BANK OF NOVA SCOTIA, as a Lender

By: /s/ Mark Sparrow
Name: Mark Sparrow
Title: Director

BANK OF MONTREAL, as a Lender

By: /s/ Gumaro Tijerina
Name: Gumaro Tijerina
Title: Director

UNION BANK, N.A., as a Lender

By: /s/ Lara Sorokolit
Name: Lara Sorokolit
Title: Vice President

CITIBANK, N.A., as a Lender

By: /s/ Eamon Baqui
Name: Eamon Baqui
Title: Vice President

JPMORGAN CHASE BANK, N.A., as a Lender

By: /s/ Mark E. Olson
ROYAL BANK OF CANADA, as a Lender
By:  /s/ Mark Lumpkin, Jr.
Name: Mark Lumpkin, Jr.
Title: Authorized Signatory

THE ROYAL BANK OF SCOTLAND plc, as a Lender
By:  /s/ Sanjay Remond
Name: Sanjay Remond
Title: Authorised Signatory

SANTANDER BANK, N.A., as a Lender
By:  /s/ Aidan Lanigan
Name: Aidan Lanigan
Title: Senior Vice President

U.S. BANK NATIONAL ASSOCIATION, as a Lender
By:  /s/ Jonathan H. Lee
Name: Jonathan H. Lee
Title: Vice President

COMPASS BANK, as a Lender
By:  /s/ Umar Hassan
Name: Umar Hassan
Title: Vice President

COMERICA BANK, as a Lender
By:  /s/ Caroline M. McClurg
Name: Caroline M.
McClurg
Title: Assistant Vice President

CREDIT SUISSE AG, Cayman Islands Branch, as a Lender

By: /s/ Nupur Kumar
Name: Nupur Kumar
Title: Authorized Signatory

By: /s/ Michael Spaight
Name: Michael Spaight
Title: Authorized Signatory

TORONTO DOMINION (TEXAS) LLC, as a Lender

By: /s/ Masood Fikree
Name: Masood Fikree
Title: Authorized Signatory

CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK, as a Lender

By: /s/ Mark Roche
Name: Mark Roche
Title: Managing Director

By: /s/ Michael D. Willis
Name: Michael D. Willis
Title: Managing Director

FIFTH THIRD BANK, as a Lender

By: /s/ Byron Cooley
Name: Byron Cooley
Title: Executive Director

MIZUHO BANK LTD., as a Lender

By: /s/ Raymond Ventura
Name: Raymond Ventura
Title: Deputy General Manager
ONEWEST BANK, FSB,  
as a Lender  

By: /s/ Sean Murphy  
Name: Sean Murphy  
Title: Executive Vice President  

SUNTRUST BANK,  
as a Lender  

By: /s/ Chulley Bogle  
Name: Chulley Bogle  
Title: Vice President  

_ Tenth Amendment_
ELEVENTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT

THIS ELEVENTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT (hereinafter called this “Amendment”) is dated effective as of February 21, 2014, by and among BREITBURN OPERATING L.P., a Delaware limited partnership (the “Company”), BREITBURN ENERGY PARTNERS L.P., as Parent Guarantor (the “Parent”), BreitBurn GP, LLC (the “Parent GP”), BreitBurn Operating GP, LLC (the “General Partner”), the Subsidiaries of the Parent and/or the Company, as guarantors (the “Subsidiary Guarantors”), and together with the Parent, the Parent GP, and the General Partner, the “Guarantors”), EACH LENDER SIGNATORY HERETO, and WELLS FARGO BANK, NATIONAL ASSOCIATION, as administrative agent for the Lenders (in such capacity, together with its successors in such capacity “Administrative Agent”). Capitalized terms used in this Amendment, and not otherwise defined in this Amendment, have the meanings assigned thereto in the Credit Agreement defined below.

WITNESSETH:

WHEREAS, the Company, the Guarantors, Administrative Agent, Issuing Lender and the lenders from time to time party thereto (the “Lenders”) are parties to that certain Second Amended and Restated Credit Agreement dated as of May 7, 2010, as amended by the following: that certain First Amendment to Second Amended and Restated Credit Agreement and Consent and First Amendment to Security Agreement dated as of September 17, 2010, Second Amendment dated as of May 9, 2011, Third Amendment dated as of August 3, 2011, Fourth Amendment dated as of October 5, 2011, Fifth Amendment dated as of May 25, 2012, Sixth Amendment dated as of October 11, 2012, Seventh Amendment dated as of February 26, 2013, Eighth Amendment to Second Amended and Restated Credit Agreement dated as of May 22, 2013, Ninth Amendment to Second Amended and Restated Credit Agreement dated as of July 15, 2013 and Tenth Amendment to Second Amended and Restated Credit Agreement dated as of November 6, 2013 (as further amended, modified or restated from time to time, the “Credit Agreement”), whereby upon the terms and conditions therein stated the Lenders have agreed to make certain loans to the Company upon the terms and conditions set forth therein;

WHEREAS, the Company has requested that the Lenders amend the Credit Agreement as set forth below; and

WHEREAS, subject to the terms hereof, the undersigned Lenders are willing to agree to the amendments to the Credit Agreement as set forth herein.

NOW, THEREFORE, for and in consideration of the mutual covenants and agreements herein contained, the parties to this Amendment hereby agree as follows:

SECTION 1. Amendments to Credit Agreement. Effective as of the Amendment Effective Date, the Credit Agreement is hereby amended as follows:

(a) Section 1.01 of the Credit Agreement is amended by deleting the definition of “Triggering Event”.

(b) Section 8.05(e) of the Credit Agreement is amended and restated in its entirety as follows:

“(e) Senior Unsecured Notes and guaranties given by the Company, the Parent or any Subsidiary that is a guarantor hereunder with respect thereto; provided that the principal amount of such Senior Unsecured Notes shall not exceed the Borrowing Base in effect at the time of issuance (before giving pro forma effect to the attendant automatic reduction in the Borrowing Base required by the second proviso of this clause (e)), further provided that, the Borrowing Base shall automatically reduce on the date of such issuance of Senior Unsecured Notes by an amount equal to 25% of the stated principal amount of such Senior Unsecured Notes, except to the extent that the proceeds from the issuance of such Senior Unsecured Notes are used to refinance all or a portion of the principal amount of Senior Unsecured Notes existing at such time;”

(c) Section 8.14 of the Credit Agreement is amended and restated in its entirety as follows:

“Section 8.14 Interest Coverage Ratio .”
Parent shall not permit the ratio of EBITDAX to Consolidated Interest Expense for the four fiscal quarters ending on the last day of each fiscal quarter beginning with the fiscal quarter ended December 31, 2013, to be less than 2.50 to 1.00.”

(d) Section 8.15 of the Credit Agreement is amended and restated in its entirety as follows:

“8.15 Reserved.”

SECTION 2. Guarantor Confirmation.

(a) The Guarantors hereby consent and agree to this Amendment and each of the transactions contemplated hereby.

(b) The Company and each Guarantor ratifies and confirms the debts, duties, obligations, liabilities, rights, titles, pledges, grants of security interests, liens, powers, and privileges existing by virtue of the Loan Documents to which it is a party.

(c) The Company and each Guarantor agrees that the guarantees, pledges, grants of security interests and other obligations, and the terms of each of the Security Agreements and Guaranties to which it is a party, are not impaired, released, diminished or reduced in any manner whatsoever and shall continue to be in full force and effect and shall continue to secure all Obligations.

(d) The Company and each Guarantor acknowledges and agrees that all terms, provisions, and conditions of the Loan Documents to which it is a party (as amended by this Amendment) shall continue in full force and effect and shall remain enforceable and binding in accordance with their respective terms.

SECTION 3. Conditions of Effectiveness. This Amendment and the amendments hereunder shall become effective as of the date first set forth above (the “Amendment Effective Date”), provided that the following conditions shall have been satisfied:

(a) Amendment. The Administrative Agent shall have received a counterpart of this Amendment which shall have been executed by the Administrative Agent, the Issuing Lender, each of the Lenders, the Company, and the Guarantors (which may be by telecopy or PDF transmission).

(b) No Default; Representations and Warranties. As of the Amendment Effective Date:

(i) the representations and warranties of the Company and the Guarantors in Article VI of the Credit Agreement and in the other Loan Documents as amended hereby shall be true and correct in all material respects (except to the extent such representations and warranties expressly refer to an earlier date, in which case they shall be true and correct as of such earlier date, and except that the representations and warranties contained in clauses (a) and (b) of Section 6.14 of the Credit Agreement shall be deemed to refer to the most recent statements furnished pursuant to clauses (a) and (b) of Section 7.01 of the Credit Agreement);

(ii) no Default or Event of Default shall exist; and

(iii) since December 31, 2012, there shall have been no event, development or circumstance that has had or could reasonably be expected to have a Material Adverse Effect.

(c) Payment of Fees. The Company shall have paid all accrued and unpaid fees, costs and expenses owed pursuant to this Amendment to the extent then due and payable on the Amendment Effective Date.

(d) Additional Documents. Such other documents, in form and substance satisfactory to Administrative Agent, as the Administrative Agent may reasonably request.

SECTION 4. Representations and Warranties. Each of the Company and the Parent represents and warrants to Administrative Agent and the Lenders, with full knowledge that such Persons are relying on the following representations and warranties in executing this Amendment, as follows:

(a) It has the organizational power and authority to execute, deliver and perform this Amendment, and all organizational action on the part of it requisite for the due execution, delivery and performance of this Amendment has been duly and effectively taken.

(b) The Credit Agreement, as amended by this Amendment, the Loan Documents and each and every document
executed and delivered to the Administrative Agent and the Lenders in connection with this Amendment to which it is a party constitute the legal, valid and binding obligations of it, to the extent it is a party thereto, enforceable against such Person in accordance with their respective terms except as enforceability may be limited by applicable bankruptcy, insolvency, or similar laws affecting the enforcement of creditors’ rights generally or by equitable principles relating to enforceability.

(c) This Amendment does not and will not violate any provisions of any of the Organization Documents of the Company.

(d) No approval, consent, exemption, authorization, or other action by, or notice to, or filing with, any Governmental Authority is necessary or required in connection with the execution, delivery or performance by, or enforcement against, any Loan Party of this Amendment.

(e) After giving effect to this Amendment, no Default or Event of Default will exist, and all of the representations and warranties contained in the Credit Agreement and in the other Loan Documents are true and correct in all material respects on and as of this date (except to the extent such representations and warranties expressly refer to an earlier date, in which case they shall be true and correct as of such earlier date).

SECTION 5. Reference to and Effect on the Credit Agreement.

(a) Upon the effectiveness hereof, on and after the date hereof, each reference in the Credit Agreement to “this Agreement,” “hereunder,” “hereof,” “herein,” or words of like import, shall mean and be a reference to the Credit Agreement as amended hereby.

(b) Except as specifically amended by this Amendment, the Credit Agreement shall remain in full force and effect and is hereby ratified and confirmed.

SECTION 6. Extent of Amendments. Except as otherwise expressly provided herein, the Credit Agreement and the other Loan Documents are not amended, modified or affected by this Amendment. Each of the Company and the Parent hereby ratifies and confirms that (i) except as expressly amended hereby, all of the terms, conditions, covenants, representations, warranties and all other provisions of the Credit Agreement remain in full force and effect, (ii) each of the other Loan Documents are and remain in full force and effect in accordance with their respective terms, and (iii) the Collateral and the Liens on the Collateral securing the Obligations are unimpaired by this Amendment and remain in full force and effect.

SECTION 7. Loan Documents. The Loan Documents, as such may be amended in accordance herewith, are and remain legal, valid and binding obligations of the parties thereto, enforceable in accordance with their respective terms. This Amendment is a Loan Document.

SECTION 8. Claims. As additional consideration to the execution, delivery, and performance of this Amendment by the parties hereto and to induce Administrative Agent and Lenders to enter into this Amendment, each of the Company and the Parent represents and warrants that, as of the date hereof, it does not know of any defenses, counterclaims or rights of setoff to the payment of any Indebtedness of the Company or the Parent to Administrative Agent, Issuing Lender or any Lender.

SECTION 9. Execution and Counterparts. This Amendment may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of this Amendment by facsimile or pdf shall be equally as effective as delivery of a manually executed counterpart.

SECTION 10. Governing Law. This Amendment shall be governed by and construed in accordance with the laws of the State of New York and applicable federal laws of the United States of America.

SECTION 11. Headings. Section headings in this Amendment are included herein for convenience and reference only and shall not constitute a part of this Amendment for any other purpose.

LENDER AND/OR LENDERS REPRESENT THE FINAL AGREEMENT BETWEEN SUCH PARTIES, AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS BY SUCH PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN SUCH PARTIES.

SECTION 13. **No Waiver.** Each of the Company and the Parent hereby agrees that no Event of Default and no Default has been waived or remedied by the execution of this Amendment by the Administrative Agent or any Lender. Nothing contained in this Amendment nor any past indulgence by the Administrative Agent, Issuing Lender or any Lender, nor any other action or inaction on behalf of the Administrative Agent, Issuing Lender or any Lender, (i) shall constitute or be deemed to constitute a waiver of any Defaults or Events of Default which may exist under the Credit Agreement or the other Loan Documents, or (ii) shall constitute or be deemed to constitute an election of remedies by the Administrative Agent, Issuing Lender or any Lender, or a waiver of any of the rights or remedies of the Administrative Agent, Issuing Lender or any Lender provided in the Credit Agreement, the other Loan Documents, or otherwise afforded at law or in equity.

[Signature Pages Follow]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered by their proper and duly authorized officers as of the day and year first above written.

**LOAN PARTIES:**

**BREITBURN OPERATING L.P.,** a Delaware limited partnership
  
  By: **BreitBurn Operating GP, LLC,** its general partner

**BREITBURN ENERGY PARTNERS L.P.,** a Delaware limited partnership
  
  By: **BreitBurn GP, LLC,** its general partner

**BREITBURN OPERATING GP, LLC,** a Delaware limited partnership

**BREITBURN FINANCE CORPORATION,** a Delaware corporation

**BREITBURN MANAGEMENT COMPANY, LLC,** a Delaware limited liability company

**ALAMITOS COMPANY,** a California corporation

**BREITBURN FLORIDA LLC,** a Delaware limited liability company
  
  By: **BreitBurn Operating L.P.,** its sole member
  
  By: **BreitBurn Operating GP, LLC,** its general partner

**BREITBURN FULTON LLC,** a Delaware limited liability company

**BEAVER CREEK PIPELINE, L.L.C.,** a Michigan limited liability company

**GTG PIPELINE LLC,** a Virginia limited liability company

**MERCURY MICHIGAN COMPANY, LLC,** a Michigan limited liability company

**TERRA ENERGY COMPANY LLC,** a Michigan limited liability company

**TERRA PIPELINE COMPANY LLC,** a Michigan limited liability company

**PHOENIX PRODUCTION COMPANY,** a Wyoming corporation

**BREITBURN TRANSPETCO GP LLC,** a Delaware limited liability company
  
  By: **BreitBurn Operating L.P.,** its sole member
  
  By: **BreitBurn Operating GP, LLC,** its general partner

**BREITBURN TRANSPETCO LP LLC,** a Delaware limited liability company
  
  By: **BreitBurn Operating L.P.,** its sole member
  
  By: **BreitBurn Operating GP, LLC,** its general partner

**TRANSPETCO PIPELINE COMPANY, L.P.,** a Delaware limited partnership
  
  By: **BreitBurn Operating L.P.,** on behalf of itself and as the sole member of **BreitBurn Transpetco GP LLC,** each a general partner
  
  By: **BreitBurn Operating GP, LLC,** its general partner
BREITBURN OKLAHOMA LLC, a Delaware limited liability company
By: BreitBurn Operating L.P., its sole member
By: BreitBurn Operating GP, LLC, its general partner

By: /s/ James G. Jackson
James G. Jackson
Chief Financial Officer

PARENT GP:

BREITBURN GP, LLC, a Delaware limited partnership

By: /s/ James G. Jackson
James G. Jackson
Chief Financial Officer

WELLS FARGO BANK, NATIONAL ASSOCIATION as Administrative Agent, Issuing Lender, Swing Line Lender and a Lender

By: /s/ Matt Turner
Matt Turner
Vice President

THE BANK OF NOVA SCOTIA, as a Lender

By: /s/ Terry Donovan
Name: Terry Donovan
Title: Managing Director

BANK OF MONTREAL, as a Lender

By: /s/ Gumaro Tijerina
Name: Gumaro Tijerina
Title: Managing Director

UNION BANK, N.A., as a Lender

By: /s/ Lara Sorokolit
Name: Lara Sorokolit
Title: Vice President

BARCLAYS BANK PLC, as a Lender
By: /s/ Vanessa A. Kurbatskiy

Name: Vanessa A.
Title: Vice President

By: /s/ David Morris
Name: David Morris
Title: Authorized Officer

By: /s/ Mark Lumpkin, Jr.
Name: Mark Lumpkin,
Title: Authorized
Signatory

By: /s/ Sanjay Remond
Name: Sanjay Remond
Title: Director

By: /s/ Aidan Lanigan
Name: Aidan Lanigan
Title: Senior Vice
President

By: /s/ Puiki Lok
Name: Puiki Lok
Title: Vice President

By: /s/ Umar Hassan
Name: Umar Hassan
Title: Vice President

JPMORGAN CHASE BANK, N.A.,
as a Lender

ROYAL BANK OF CANADA,
as a Lender

THE ROYAL BANK OF SCOTLAND plc,
as a Lender

SANTANDER BANK, N.A.,
as a Lender

COMPASS BANK,
as a Lender

COMERICA BANK,
as a Lender
By: /s/ Mark Fuqua
Name: Mark Fuqua
Title: Senior Vice President

CREDIT SUISSE AG, Cayman Islands Branch,
as a Lender

By: /s/ Michael Spaight
Name: Michael Spaight
Title: Authorized Signatory

By: /s/ Samuel Miller
Name: Samuel Miller
Title: Authorized Signatory

TORONTO DOMINION (TEXAS) LLC,
as a Lender

By: /s/ Masood Fikree
Name: Masood Fikree
Title: Authorized Signatory

CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK,
as a Lender

By: /s/ Mark Roche
Name: Mark Roche
Title: Managing Director

By: /s/ Michael D. Willis
Name: Michael D. Willis
Title: Managing Director

FIFTH THIRD BANK,
as a Lender

By: /s/ Byron Cooley
Name: Byron Cooley
Title: Executive Director

MIZUHO BANK LTD.,
as a Lender

By: /s/ Raymond Ventura
Name: Raymond Ventura
Title: Deputy General Manager
ONEWEST BANK, FSB,  
as a Lender  

By: /s/ Sean Murphy  

Name: Sean Murphy  
Title: Executive Vice President

SUNTRUST BANK,  
as a Lender  

By: /s/ Chulley Bogle  

Name: Chulley Bogle  
Title: Vice President

BRANCH BANKING AND TRUST COMPANY,  
as a Lender  

By: /s/ Parul June  

Name: Parul June  
Title: Vice President

Eleventh Amendment
Pursuant to this Convertible Phantom Unit Agreement, (the “Agreement”), BreitBurn GP, LLC (the “Company”), as the general partner of BreitBurn Energy Partners L.P., a Delaware limited partnership (the “Partnership”), hereby grants to [_____________] (the “Participant”) the following award of Convertible Phantom Units (“CPUs”), pursuant and subject to the terms and conditions of this Agreement and the Partnership’s First Amended and Restated 2006 Long-Term Incentive Plan (the “Plan”), the terms and conditions of which are hereby incorporated into this Agreement by reference. Each CPU is hereby granted in tandem with a corresponding Performance Distribution Right (“PDR”), as further detailed in Section 3 below. Each CPU and PDR shall constitute an “Other Unit-Based Award” under the terms of the Plan. Except as otherwise expressly provided herein (including on Exhibit A hereto), all capitalized terms used in this Agreement, but not otherwise defined, shall have the meanings provided in the Plan.

GRANT NOTICE

Subject to the terms and conditions of this Agreement, the principal features of this Award are as follows:

Number of CPUs : [_____]

Grant Date : January 29, 2014

Vesting of CPUs : The CPUs shall vest and the number of CUEs underlying such CPUs shall be determined in accordance with Section 3 below (if any) on the earliest to occur of (i) an applicable accelerated vesting date set forth in Section 4 below, and (ii) December 28, 2016, in each case subject to the Participant’s continued employment with the Employer through any such date (any such date, a “Vesting Date”). For vesting purposes, any per Unit distribution that is announced after an applicable Vesting Date, but prior to the payment of Units underlying the vesting CPU, shall be disregarded for purposes of determining the Unit conversion level applicable to such CPU.

Separation from Service : In the event of the Participant’s Separation from Service prior to December 28, 2016, the vesting and termination of the CPUs shall be governed in accordance with the provisions of Section 4 below.

Payment of CPUs : Vested CPUs shall be paid to the Participant in the form of Units as set forth in Section 5 below, subject to Section 17 below.

PDRs : Each CPU granted under this Agreement shall be issued in tandem with a corresponding PDR, which shall entitle the Participant to receive an amount determined by reference to Partnership distributions and which shall be credited to the Participant in the form of additional CPUs in accordance with Section 2 of this Agreement.
TERMS AND CONDITIONS OF CONVERTIBLE PHANTOM UNITS

1. **Grant of CPUs**. The Partnership hereby grants to the Participant, as of the Grant Date, an award of [_______] CPUs, subject to all of the terms and conditions contained in this Agreement and the Plan.

2. **Grant of Tandem PDR**.
   
a. **General**. Each CPU granted or credited hereunder shall be issued in tandem with a corresponding PDR, which PDR shall remain outstanding from the Grant Date until the earlier to occur of a Payment Date (as defined below) or the forfeiture of the CPU to which such PDR corresponds. Pursuant to each PDR, the Participant shall be entitled to receive an amount, credited in the form of additional CPUs as set forth in the following sentence, equal to the product of (i) the aggregate per Unit distributions paid by the Partnership in respect of each month, through which the PDR remains outstanding, beginning with the distribution paid in January 2014, (provided that the PDR is outstanding as of the record date set by the Board of Directors of the Company for such distribution, except with respect to the distribution paid in January 2014) (including any extraordinary non-recurring distributions paid during a month), if any, times (ii) the number of common unit equivalents (“CUEs”) underlying the relevant CPU during such month (as determined in accordance with Section 2(b) below), divided by the closing price of the Unit on the date on which such distribution is paid to Unitholders. All such PDRs shall be credited to the Participant in the form of additional CPUs as of the date of payment of any such distribution based on the Fair Market Value of a Unit on such date. Each additional CPU which results from such crediting of PDRs granted hereunder shall be subject to the same vesting, forfeiture, payment or distribution, adjustment and other provisions which apply to the underlying CPU to which such additional CPU relates. PDRs shall not entitle the Participant to any amounts relating to distributions occurring after the earlier to occur of the applicable Payment Date or the Participant’s forfeiture of the CPU to which such PDR relates in accordance herewith.

b. **Determination of CUEs Underlying CPUs for PDR Purposes**. For purposes of determining the payments, if any, in respect of PDRs for a given calendar month under Section 2(a) above, the number of CUEs underlying a CPU shall equal the number of CUEs listed on the CUE Conversion Table for the corresponding dollar value (in the column entitled “Target Annual Distribution Level”) attained by multiplying the applicable Monthly Distribution by twelve.

c. **Separate Payments**. The PDRs and any amounts that may become payable in respect thereof shall be treated separately from the CPUs and the rights arising in connection therewith for purposes of the designation of time and form of payments required by Code Section 409A.

3. **Conversion of Vested CPUs to Units**.
   
a. **General**. CPUs that vest in accordance with this Agreement shall represent the right to receive payment, in accordance with Section 5 below, in the form of a number of Units equal to (i) the product of (A) the number of CPUs so vested, times (B) the number of CUEs
underlying such CPUs on the applicable Vesting Date (as determined in accordance with Section 3(b) below), minus (ii) the applicable number of PDR Equalization Units (as defined below), if any (such number of Units, the “Resultant Units”). Unless and until a CPU vests, the Participant will have no right to payment of Units in respect of any such CPU. Prior to actual payment in respect of any vested CPU, such CPU will represent an unsecured obligation of the Partnership, payable (if at all) only from the general assets of the Partnership.

b. Determination of CUEs Underlying CPUs at Vesting. The number of CUEs underlying each CPU at vesting shall equal:

i. In the case of any CPU that vests on December 28, 2016, a number of CUEs determined by matching the dollar value (in the column entitled “Target Annual Distribution Level”) of the product of (x) twelve, and (y) the Monthly Distribution paid in November 2016, with the corresponding number of CUEs listed on the CUE Conversion Table; and

ii. In the case of any CPU that vests upon a Separation from Service in accordance with Section 4(a), 4(b), or 4(c) below, in any case, prior to December 28, 2016, a number of CUEs determined by (A) matching the dollar value (in the column entitled “Target Annual Distribution Level”) of the product of (x) twelve, multiplied by (y) the higher of (i) the per Unit Monthly Distribution paid or payable by the Partnership for the full calendar month ended immediately prior to such Separation from Service (for purposes of clarification, if the Monthly Distribution was zero, the Monthly Distribution in this clause (i) shall be zero), or (ii) the per Unit Monthly Distribution publicly announced by the Partnership prior to such Separation from Service for the calendar month in which the Separation from Service occurs, in any case, with the corresponding number of CUEs listed on the CUE Conversion Table, and (B) multiplying such number of CUEs by the applicable CPU Acceleration Percentage (as determined in accordance with the CPU Acceleration Percentage Table attached hereto as Exhibit C, based on the date of such Separation from Service).

Under no circumstances shall any Monthly Distribution that is announced after the applicable Vesting Date be taken into consideration in determining the number of CUEs underlying any CPUs at vesting.

c. PDR Equalization Units. For purposes of this Agreement, “PDR Equalization Units” means a number of Units equal to the difference between (A) the actual aggregate number of CPUs credited to the Participant as a result of PDRs from the Grant Date through the Payment Date (the “Actual PDRs”), and (B) the aggregate number of CPUs that would have been credited to the Participant as a result of PDRs during the period from the Grant Date through the Payment Date had the PDRs originally been granted in tandem with that number of CPUs equal to the aggregate number of CUEs underlying the CPUs as of the applicable Vesting Date (the “Notional PDRs”). If the number of Actual PDRs does not exceed the number of Notional PDRs with respect to any vesting CPU, then the PDR Equalization Units shall equal zero with respect to such CPU.
4. **Separation from Service**. If the Participant experiences a Separation from Service from the Employer prior to the vesting or termination of the CPUs, the following provisions shall control the vesting and forfeiture of the CPUs in connection with and following such Separation from Service:

   a. **Good Reason; Other than for Cause, Death or Disability**. If, during the Employment Period, the Participant incurs a Separation from Service by reason of a termination by the Employer without Cause (other than as a consequence of the Participant’s death or Disability), or by reason of a termination by the Participant for Good Reason, then, to the extent not previously vested or forfeited, the CPUs shall vest and the number of CUEs underlying such CPUs shall be determined as of the date of such Separation from Service on a pro rata basis in accordance with Sections 3(a) and 3(b)(ii) above, and any CPUs that do not so vest and convert into Units shall automatically be cancelled and forfeited as of the date of such Separation from Service.

   b. **Death or Disability**. If, during the Employment Period, the Participant incurs a Separation from Service due to the Participant’s death or Disability, then, to the extent not previously vested or forfeited, the CPUs shall vest and the number of CUEs underlying such CPUs shall be determined as of the date of such Separation from Service on a pro rata basis in accordance with Sections 3(a) and 3(b)(ii) above (and, in the case of the Participant’s death, paid to Participant’s estate), and any CPUs that do not so vest and convert into Units shall be cancelled and forfeited as of the date of such Separation from Service.

   c. **Employer Non-renewal**. If the Participant incurs a Separation from Service because the Employer elects not to renew the Employment Period in accordance with Section 2 of the Employment Agreement and, at the time of such non-renewal, the Participant was willing and able to continue providing services in accordance with the terms and conditions of the Employment Agreement (in any case, a “Non-Renewal”), then, to the extent not previously vested or forfeited, the CPUs shall vest and the number of CUEs underlying such CPUs shall be determined as of the date of such Separation from Service on a pro rata basis in accordance with Sections 3(a) and 3(b)(ii) above, provided, that the vesting and conversion described in this Section 4(c) shall only occur if, following notice of such Non-Renewal, the Participant does not voluntarily terminate his employment (other than upon death or Disability) before the end of the Employment Period, as determined without regard to any extension of the Employment Period that might otherwise occur following the date of such Separation from Service in accordance with the second sentence of Section 2 of the Employment Agreement. Any CPUs that do not vest and convert into Units in accordance with this Section 4(c) upon a Non-Renewal shall automatically be cancelled and forfeited as of the date of such Separation from Service.

   d. **Cause; Resignation Other than for Good Reason**. If the Participant’s employment with the Employer is terminated by the Employer for Cause or by the Participant without Good Reason (and other than due to the Participant’s death or Disability), then, to the extent not previously vested, all CPUs subject to this Agreement shall be forfeited as of the date of such Separation from Service.

5. **Payment of CPUs; Issuance of Units**. CPUs that vest shall be paid to the Participant in the form of Units in a lump-sum amount determined in accordance with Section 3 above during the sixty-day period following the applicable Vesting Date, with the exact date of
payment determined by the Company in its sole discretion (the date on which Units are transferred to the Participant, the “Payment Date”). All CPUs shall be canceled and terminated upon such payment, and the Participant shall have no further right or interest in respect thereof.

6. Forfeiture and Termination of CPUs.

   a. Termination of Employment. Without limiting the foregoing, in the event of the Participant’s termination of employment for any reason, (i) the CPUs, to the extent not vested as of the date of such termination of employment, and any corresponding PDRs, shall thereupon automatically and without further action be cancelled and forfeited by the Participant, and the Participant shall have no further right or interest in or with respect to such unvested CPUs and corresponding PDRs, and (ii) no portion of the CPUs which are unvested as of the date of such termination of employment shall thereafter become vested.

   b. Failure to Achieve Minimum Performance. In the event that, as of December 28, 2016 or any earlier Vesting Date, the number of Resultant Units is less than or equal to zero, the CPUs and any corresponding PDRs shall thereupon automatically and without further action be cancelled and forfeited by the Participant, and the Participant shall have no further right or interest in such CPUs or any corresponding PDRs or with respect to either of the foregoing.

7. Tax Withholding. The Company and/or its Affiliates shall have the authority and the right to deduct or withhold, or to require the Participant to remit to the Company and/or its Affiliates, an amount sufficient to satisfy all applicable federal, state and local taxes (including the Participant’s employment tax obligations) required by law to be withheld with respect to any taxable event arising in connection with the CPUs and/or the PDRs. To the extent that such obligation arises at the time that the CPUs vest or are paid to the Participant in Units, the Company and/or its Affiliates may withhold Units otherwise issuable in respect of such CPUs having a Fair Market Value equal to the sums required to be withheld in satisfaction of the foregoing requirements. Notwithstanding any other provision of the Plan or this Agreement, the number of Units which may be so withheld in order to satisfy the Participant’s income and payroll tax liabilities with respect to the issuance, vesting or payment of the CPUs shall be limited to the number of Units which have a Fair Market Value on the date of withholding equal to the aggregate amount of such liabilities based on the minimum statutory withholding rates for income and payroll tax purposes that are applicable to such supplemental taxable income.

8. Rights as Unit Holder. Neither the Participant nor any person claiming under or through the Participant shall have any of the rights or privileges of a holder of Units in respect of any Units that may become deliverable hereunder unless and until certificates representing such Units shall have been issued or recorded in book entry form on the records of the Partnership or its transfer agents or registrars, and delivered in certificate or book entry form to the Participant or any person claiming under or through the Participant.

9. Non-Transferability. Except as otherwise provided in this Section 9, (i) neither the CPUs nor the PDRs may be sold, pledged, assigned or transferred in any manner other than by will or the laws of descent and distribution, and (ii) neither the CPUs, PDRs nor any interest or right therein shall be liable for the debts, contracts or engagements of the Participant or his or her successors in interest or shall be subject to disposition by transfer, alienation, anticipation,
pledge, encumbrance, assignment or any other means whether such disposition be voluntary or involuntary or by operation of law by judgment, levy, attachment, garnishment or any other legal or equitable proceedings (including bankruptcy), and any attempted disposition thereof shall be null and void and of no effect, except to the extent that such disposition is permitted by the preceding sentence. Notwithstanding the foregoing, subject to applicable law, the CPUs and PDRs may be transferred to an estate planning trust that constitutes a “family member” of the Participant within the meaning of the instructions to Form S-8 under the Securities Act, subject to the following terms and conditions: (i) any CPUs or PDRs so transferred shall not be further assignable or transferable by the transferee other than by will or the laws of descent and distribution; (ii) any CPUs or PDRs so transferred shall continue to be subject to all the terms and conditions of the CPUs and PDRs as applicable to the original Participant (other than the ability to further transfer the CPUs and PDRs); and (iii) the Participant and the transferee shall execute any and all documents requested by the Committee, including, without limitation documents to (A) confirm the status of the transferee as a permitted transferee, (B) satisfy any requirements for an exemption for the transfer under applicable federal, state and foreign securities laws, and (C) evidence the transfer.

10. Distribution of Units. The Units issued pursuant to this Agreement shall be held in book entry form and no certificates shall be issued therefor; provided, that certificates may be issued representing such Units at the request of the Participant and in accordance with the Partnership’s governing documents, as amended and supplemented from time to time. Notwithstanding anything herein to the contrary, (a) no payment shall be made under this Agreement in the form of Units unless such Units issuable upon such payment are then registered under the Securities Act of 1933, as amended (the “Securities Act”) or, if such Units are not then so registered, the Company has determined that such payment and issuance would be exempt from the registration requirements of the Securities Act, and (b) the Partnership shall not be required to issue or deliver any Units (whether in certificated or book-entry form) pursuant to this Agreement unless (i) such issuance and delivery are in compliance with all applicable laws and regulations and, if applicable, the requirements of any exchange on which the Units are listed or traded, and (ii) any consent or approval of any governmental or regulatory authority necessary as a condition to such issuance and delivery to the Participant (or his or her estate) has been obtained. Any certificates delivered pursuant to this Agreement shall be subject to any stop-transfer orders and other restrictions as the Company deems necessary or advisable to comply with federal, state, or local securities or other laws, rules and regulations and the rules of any national securities exchange or automated quotation system on which the Units are listed, quoted, or traded. The Company may place legends on any certificate to reference restrictions applicable to the Units. In addition to the terms and conditions provided herein, the Company may require that the Participant make such covenants, agreements, and representations as the Company, in its sole discretion, deems necessary or advisable to comply with federal, state, or local securities or other laws, rules and regulations and any generally applicable timing or other restrictions with respect to the settlement of any CPUs pursuant to this Agreement, including a window-period limitation, as may be imposed in its discretion. No fractional Units shall be issued or delivered pursuant to the CPUs.

11. Partnership Agreement. Units issued upon payment of the CPUs shall be subject to the terms of the Plan and the terms of the Partnership Agreement. Upon the issuance
of Units to the Participant, the Participant shall, automatically and without further action on his or her part, be deemed to be a party to, signatory of and bound by the Partnership Agreement.

12. **No Effect on Employment**. Nothing in this Agreement or in the Plan shall confer upon the Participant any right to serve or continue to serve as an Employee, Director or Consultant.

13. **Severability**. If any provision in this Agreement is held invalid or unenforceable, such provision will be severable from, and such invalidity or unenforceability will not be construed to have any effect on, the remaining provisions of this Agreement, which shall remain in full force and effect.

14. **Tax Consultation**. None of the Partnership, the Company or any of their Affiliates has made any warranty or representation to Participant with respect to the income tax consequences of the issuance of the CPUs, the PDRs, the Units or the transactions contemplated by this Agreement, and Participant is in no manner relying on such entities or their representatives for an assessment of such tax consequences. The Participant understands that the Participant may suffer adverse tax consequences in connection with the CPUs and PDRs granted pursuant to this Agreement. The Participant represents that the Participant has consulted with any tax consultants that the Participant deems advisable in connection with the CPUs and the PDRs and that the Participant is not relying on the Company, the Partnership or their Affiliates for tax advice.

15. **Amendments, Suspension and Termination**. Except as provided in the Section 17 hereof, this Agreement cannot be modified, altered or amended, except by an agreement, in writing, signed by both the Partnership and the Participant.

16. **Conformity to Securities Laws**. The Participant acknowledges that the Plan and this Agreement are intended to conform to the extent necessary with all provisions of the Securities Act and the Exchange Act and all regulations and rules promulgated by the Securities and Exchange Commission thereunder, and all applicable state securities laws and regulations. Notwithstanding anything herein to the contrary, the Plan shall be administered, and the CPUs and PDRs are granted, only in such a manner as to conform to such laws, rules and regulations. To the extent permitted by applicable law, the Plan and this Agreement shall be deemed amended to the extent necessary to conform to such laws, rules and regulations, but in a manner which is intended to preserve the economic value of the grant to the Participant.

17. **Code Section 409A**.

a. **General**. To the extent that the Committee determines that the CPUs, the PDRs or any amounts payable under this Agreement may not be compliant with or exempt from Code Section 409A, the Committee and the Participant shall cooperate and work together in good faith to timely amend this Agreement to the extent necessary to comply with the requirements of Code Section 409A or an exemption therefrom (including amendments with retroactive effect), or take any other actions as they deem necessary or appropriate to (a) exempt the CPUs and PDRs from Code Section 409A and/or preserve the intended tax treatment of the benefits provided with respect to the CPUs and PDRs, or (b) comply with the requirements of Code Section 409A, in any case, in a manner which is intended to preserve the economic value of the
Award to the Participant. To the extent applicable, this Agreement shall be interpreted in accordance with the provisions of Code Section 409A.

b. Potential Six-Month Delay. Notwithstanding anything to the contrary in this Agreement, no amounts shall be paid to the Participant under this Agreement prior to the expiration of the 6-month period following his Separation from Service to the extent that the Employer reasonably determines that paying such amounts at the time or times indicated in this Agreement would result in a prohibited distribution under Section 409A(a)(2)(B)(i) of the Code. If the payment of any such amounts is delayed as a result of the previous sentence, then on the first business day following the end of such 6-month period (or such earlier date upon which such amount can be paid under Code Section 409A without resulting in a prohibited distribution, including as a result of the Participant’s death), the Company shall pay to the Participant a lump-sum amount equal to the cumulative amount that would have otherwise been payable to the Participant during such 6-month period, plus interest thereon from the date of the Participant’s Separation from Service through the payment date at a rate equal to the then-current “applicable Federal rate” determined under Section 7872(f) (2)(A) of the Code.

18. Adjustments. The Participant acknowledges that the CPUs and PDRs are subject to modification and termination in certain events as provided in this Agreement and Section 7 of the Plan, provided, however, that notwithstanding anything contained in the Plan, any action taken with respect to the CPUs or PDRs under Section 7(c) (C) or Section 7(c)(E) of the Plan shall be made in a manner that is intended to preserve for the Participant the benefits or potential benefits intended to be made available under the CPUs and PDRs (including the then current value and economic terms thereof).

19. Successors and Assigns. The Company or the Partnership may assign any of their rights under this Agreement to any affiliate or successor to all or substantially all of the business or assets of the Company or the Partnership, and this Agreement shall inure to the benefit of, and be binding upon, such successors and assigns. Subject to the restrictions on transfer contained herein, this Agreement shall be binding upon the Participant and his or her heirs, executors, administrators, successors and assigns. In the event of the Participant’s death, his estate shall be entitled to any payments otherwise due to the Participant hereunder.

20. No Offset. Neither the Company nor the Partnership shall be permitted to reduce or offset the amount of any payment due to the Participant hereunder on account of any claim that the Company, the Partnership or any of their Affiliates may have against the Participant.

21. Governing Law. The laws of the State of Delaware shall govern the interpretation, validity, administration, enforcement and performance of the terms of this Agreement regardless of the law that might be applied under principles of conflicts of laws.

22. Entire Agreement. This Agreement, together with the Plan, constitutes the final, complete and exclusive agreement between the Company, the Partnership and the Participant with respect to the subject matter hereof and replaces and supersedes any and all other agreements, offers or promises, whether oral or written, made to the Participant by the Company, the Partnership or any representative or agent thereof, including, without limitation, the Employment Agreement. Without limiting the generality of the foregoing, to the extent that
this Agreement is inconsistent with the Employment Agreement regarding the terms and conditions of the CPUs or the PDRs, this Agreement shall control.

23. Captions. Captions provided herein are for convenience only and are not to serve as a basis for interpretation or construction of this Agreement.

[ Signature page follows ]
The Participant’s signature below indicates the Participant’s agreement with and understanding that this award is subject to all of the terms and conditions contained in the Plan and in this Agreement, and that, except as expressly provided in this Agreement (including, without limitation, Section 18 hereof), in the event that there are any inconsistencies between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall control. The Participant further acknowledges that the Participant has read and understands the Plan and this Agreement, which contains the specific terms and conditions of this grant of CPUs and PDRs. If the Participant is married, his or her spouse has signed the Consent of Spouse attached to this Agreement as Exhibit D. The Participant hereby agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee made in good faith upon any questions arising under the Plan or this Agreement.

PARTICIPANT:   

[Name]

BREITBURN GP, LLC

By: ______________________________

Name: Halbert S. Washburn
Title: Chief Executive Officer
EXHIBIT A
TO CONVERTIBLE PHANTOM UNIT AGREEMENT
CERTAIN DEFINITIONS

“Cause” means the following:

i. the willful and continued failure of the Participant to perform substantially the Participant’s duties for the Employer or any BreitBurn Entity (as described in Section 3(a) of the Employment Agreement) (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Participant by the Employer (after a vote to this effect by a majority of the Board (as defined in the Employment Agreement)) which specifically identifies the manner in which the Board believes that the Participant has not substantially performed the Participant’s duties and the Participant is given a reasonable opportunity of not more than twenty (20) business days to cure any such failure to substantially perform;

ii. the willful engaging by the Participant in illegal conduct or gross misconduct, in each case which is materially and demonstrably injurious to the Employer or any BreitBurn Entity; or

iii. (A) any act of fraud, or material embezzlement or material theft by the Participant, in each case, in connection with the Participant’s duties hereunder or in the course of the Participant’s employment hereunder or (B) the Participant’s admission in any court, or conviction, or plea of nolo contendere, of a felony involving moral turpitude, fraud, or material embezzlement, material theft or material misrepresentation, in each case, against or affecting the Employer or any BreitBurn Entity.

For purposes of this provision, no act or failure to act, on the part of the Participant, shall be considered “willful” unless it is done, or omitted to be done, by the Participant in bad faith or without reasonable belief that the Participant’s action or omission was in the best interests of the Employer or any BreitBurn Entity. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Employer or the Company, including, without limitation, the Board, or based upon the advice of counsel for the Employer or the Company shall be conclusively presumed to be done, or omitted to be done, by the Participant in good faith and in the best interests of the Employer and the BreitBurn Entities. Notwithstanding the foregoing, termination of the Participant’s employment shall not be deemed to be for Cause unless and until there shall have been delivered to the Participant a copy of a resolution of the Board duly adopted by an affirmative vote of the Board at a meeting of the Board held for such purpose (after reasonable notice is provided to the Participant and the Participant is given an opportunity, together with counsel for the Participant, to be heard before the Board), finding that, in the good faith opinion of the Board, the Participant is guilty of the conduct described in clauses (i), (ii) or (iii) above, and specifying the particulars thereof in detail;
provided, that if the Participant is a member of the Board, the Participant shall not vote on such resolution nor shall the Participant be counted.

“CUE Conversion Table” means the CUE Conversion Table attached as Exhibit B hereto. “Disability” means a “disability” within the meaning of Code Section 409A.

“Employer” means BreitBurn Management Company, LLC and/or BreitBurn GP, LLC, as the context requires.


“Employment Period” means the period beginning on December 30, 2010 and ending on January 1, 2014 or such earlier date upon which the Participant’s employment with the Employer is terminated, subject to extension in accordance with Section 2 of the Employment Agreement.

“Good Reason” means the occurrence of any of the following without the Participant’s written consent:

i. a material diminution in the Participant’s Base Salary (as defined in the Employment Agreement);

ii. a material diminution in the Participant’s authority, duties, or responsibilities;

iii. a material diminution in the authority, duties, or responsibilities of the supervisor to whom the Participant is required to report;

iv. a material diminution in the budget over which the Participant retains authority;

v. a material change in the geographic location at which the Participant must perform services under the Employment Agreement; or

vi. any other action or inaction that constitutes a material breach by the Employer of the Employment Agreement, including without limitation, a breach of Section 3(a)(iv) thereof;

provided, that the Participant’s resignation shall only constitute a resignation for “Good Reason” if (a) the Participant provides the Employer with written notice setting forth the specific facts or circumstances constituting Good Reason within thirty days after the initial existence of such facts or circumstances, (b) the Employer has failed to cure such facts or circumstances within thirty days after receipt of such written notice, and (c) the date of the Participant’s Separation from Service occurs no later than seventy-five days after the initial occurrence of the event constituting Good Reason.

“Monthly Distribution” means the monthly per Unit distribution paid by the Partnership, excluding any extraordinary non-recurring distribution.

“Separation from Service” means the Participant’s “separation from service” from the Employer within the meaning of Code Section 409A(a)(2)(A)(i).
## CUE Conversion Table

<table>
<thead>
<tr>
<th>Common Unit Target Distribution Level</th>
<th>Target Annual Distribution Level</th>
<th>CUEs per CPU</th>
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</thead>
<tbody>
<tr>
<td>-7</td>
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<td>0.000</td>
</tr>
<tr>
<td>-6</td>
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### EXHIBIT C

**TO CONVERTIBLE PHANTOM UNIT AGREEMENT**

**CPU ACCELERATION PERCENTAGE TABLE**

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<thead>
<tr>
<th>If a qualifying termination occurs:</th>
<th>Then the CPU Acceleration Percentage Shall Equal:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prior to December 28, 2014</td>
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</tr>
<tr>
<td>On or after December 28, 2014 and before December 28, 2015</td>
<td>33.3%</td>
</tr>
<tr>
<td>On or after December 28, 2015 and before December 28, 2016</td>
<td>66.6%</td>
</tr>
</tbody>
</table>
EXHIBIT D
TO CONVERTIBLE PHANTOM UNIT AGREEMENT

CONSENT OF SPOUSE

I, ____________________, spouse of ____________________, have read and approve the foregoing Convertible Phantom Unit Agreement (the “Agreement”). In consideration of the issuance to my spouse of the Convertible Phantom Units (“CPUs”) set forth in the Agreement, I hereby appoint my spouse as my attorney-in-fact in respect to the exercise of any rights under the Agreement and agree to be bound by the provisions thereof insofar as I may have any rights therein or in or to any CPUs or Units issued pursuant thereto under the community property laws or similar laws relating to marital property in effect in the state of our residence as of the date of the signing of the Agreement.

Dated: ________________, _____

_____________________

Signature of Spouse
Pursuant to this Restricted Phantom Unit Agreement (the “Agreement”), BreitBurn GP, LLC (the “Company”), as the general partner of BreitBurn Energy Partners L.P., a Delaware limited partnership (the “Partnership”), hereby grants to Name (the “Participant”) the following award of Restricted Phantom Units (“RPUs”), pursuant and subject to the terms and conditions of this Agreement and the Partnership’s 2006 Long-Term Incentive Plan (the “Plan”), the terms and conditions of which are hereby incorporated into this Agreement by reference. Each RPU shall constitute a Phantom Unit under the terms of the Plan and is hereby granted in tandem with a corresponding DER, as further detailed in Section 3 below. Except as otherwise expressly provided herein, all capitalized terms used in this Agreement, but not defined, shall have the meanings provided in the Plan. For purposes of this Agreement, the terms “Employer,” “Cause,” “Good Reason” and “Disability” shall have the meanings ascribed to such terms in the Employment Agreement between the Employer and the Participant, dated December 30, 2010 (the “Employment Agreement”).

GRANT NOTICE

Subject to the terms and conditions of this Agreement, the principal features of this Award are as follows:

Number of RPUs: ###

Grant Date: January [ ], 2014

Vesting of RPUs: One-third of the RPUs (rounded down to the next whole number of units, except in the case of the final vesting date) shall vest on each of December 28, 2014, December 28, 2015 and December 28, 2016 (each, a “Vesting Date”), subject to the Participant’s continued service as an Employee, Director or Consultant through each such date. In addition, the RPUs shall be subject to accelerated vesting as set forth in Section 4 below.

Termination of RPUs: In the event of the Participant’s Separation from Service (as defined in the Employment Agreement) for any reason other than those set forth in Section 4 of the “Terms and Conditions of Restricted Phantom Units,” all RPUs that have not vested prior to or in connection with such Separation from Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor.

Payment of RPUs: Vested RPUs shall be paid to the Participant in the form of Units as set forth in Section 5 below.

DERs: Each RPU granted under this Agreement shall be issued in tandem with a corresponding DER, which shall entitle the Participant to receive payments in an amount equal to Partnership distributions in accordance with Section 3 of this Agreement.
1. **Grant.** The Partnership hereby grants to the Participant, as of the Grant Date, an award of ### RPUs, subject to all of the terms and conditions contained in this Agreement and the Plan.

2. **RPUs.** Subject to Section 4 below, each RPU that vests shall represent the right to receive payment, in accordance with Section 5 below, in the form of one Unit. Unless and until an RPU vests, the Participant will have no right to payment in respect of any such RPU. Prior to actual payment in respect of any vested RPU, such RPU will represent an unsecured obligation of the Partnership, payable (if at all) only from the general assets of the Partnership.

3. **Grant of Tandem DER.** Each RPU granted hereunder is hereby granted in tandem with a corresponding DER, which DER shall remain outstanding from the Grant Date until the earlier of the payment or forfeiture of the RPU to which it corresponds. Pursuant to each DER, the Participant shall be entitled to receive payments in an amount equal to any distributions made by the Partnership in respect of the underlying Unit, if any, beginning with the distribution paid in January 2014, payable in the same form and amounts as distributions paid to the holders of Units, so long as such DER is outstanding as of the record date set by the Board of Directors of the Company for such distribution to be paid to the holders of Units, except with respect to the distribution paid in January 2014. Such payments shall be made no later than 15 days after the date of any applicable distribution paid to the holders of Units by the Partnership, except with respect to the payment for the January 2014 distribution which shall be made at the same time as the payment for the February 2014 distribution, but in no event later than the last day of the applicable two and one-half (2-1/2) month “short-term deferral” period with respect to such DER payment, within the meaning of Treasury Regulation Section 1.409A-1(b)(4). DERs shall not entitle the Participant to any payments relating to distributions occurring after the earlier to occur of the applicable RPU payment date or the forfeiture of the RPU underlying such DER. The DERs and any amounts that may become distributable in respect thereof shall be treated separately from the RPUs and the rights arising in connection therewith for purposes of the designation of time and form of payments required by Code Section 409A.

4. **Vesting and Termination.**

   (a) **General.** The RPUs shall vest in such amounts and at such times as are set forth in the Grant Notice above, provided, that the RPUs shall vest in full upon any earlier occurrence of (a) the Participant’s Separation from Service without Cause, for Good Reason or due to the Participant’s death or Disability, or (b) a Change of Control and, in any case, shall be subject to the payment provisions contained in Section 5 below. No portion of the RPUs which has not become vested at the date of the Participant’s Separation from Service shall thereafter become vested. In the event of the Participant’s Separation from Service for any reason other than as set forth in (a) of this Section, all RPUs that have not vested prior to or in connection with such Separation from Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor.

   (b) **Change of Control Definition.** “Change of Control” means, and shall be deemed to have occurred upon one or more of the following events:
(i) any “person” or “group” within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an Affiliate of the Company, shall become the beneficial owner, directly or indirectly, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests or of a controlling interest in BreitBurn Management Company, LLC, the Company or the Partnership;

(ii) the limited partners of the Partnership approve, in one or a series of transactions, a plan of complete liquidation of the Partnership;

(iii) the sale or other disposition by either the Company or the Partnership of all or substantially all of its assets in one or more transactions to any Person other than the Company or an Affiliate of the Company;

(iv) a transaction resulting in a Person other than the Company or an Affiliate of the Company being the general partner of the Partnership; or

(v) any time at which individuals who, as of the Grant Date, constitute the board of directors of the Company (the “Incumbent Board”) cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the Grant Date whose election, or nomination for election by the Partnership’s unitholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board will be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as the result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Incumbent Board.

5. Payment of RPUs; Issuance of Units

(a) General. Unpaid, vested RPUs shall be paid to the Participant in the form of Units in a lump-sum during the sixty-day period commencing with the earliest to occur of the following dates (the “Payment Date”) (with the exact date of payment determined by the Company in its sole discretion): (i) the applicable Vesting Date specified in the Grant Notice; (ii) the date of Participant’s Separation from Service; and (iii) the date of the Participant’s death. Payments of any RPUs that vest in accordance herewith shall be made to the Participant (or in the event of the Participant’s death, to the Participant’s estate) in whole Units in accordance with this Section 5.

(b) Potential Six-Month Delay. Notwithstanding anything to the contrary in this Agreement, no amounts payable under this Agreement shall be paid to the Participant prior to the expiration of the six-month period following his Separation from Service to the extent that the Company reasonably determines that paying such amounts prior to the expiration of such six-month period would result in a prohibited distribution under Section 409A(a)(2)(B)(i) of the Code. If the payment of any such amounts is delayed as a result of the previous sentence, then on the first business day following the end of the applicable six-month period (or such earlier date upon which such amounts can be paid under Code Section 409A without resulting in a prohibited distribution, including as a result of the Participant’s death), such amounts shall be paid to the Participant.
6. **Tax Withholding.** The Company and/or its Affiliates shall have the authority and the right to deduct or withhold, or to require the Participant to remit to the Company and/or its Affiliates, an amount sufficient to satisfy all applicable federal, state and local taxes (including the Participant’s employment tax obligations) required by law to be withheld with respect to any taxable event arising in connection with the RPUs. Without limiting the generality of Section 8(b) of the Plan, to the extent that such obligation arises at the time that the RPUs vest or are paid to the Participant in Units, the Company and/or its Affiliates may withhold Units otherwise issuable in respect of such RPUs having a Fair Market Value equal to the sums required to be withheld in satisfaction of the foregoing requirement. Notwithstanding any other provision of the Plan or this Agreement, the number of Units which may be so withheld in order to satisfy the Participant’s income and payroll tax liabilities with respect to the issuance, vesting or payment of the RPUs shall be limited to the number of Units which have a Fair Market Value on the date of withholding equal to the aggregate amount of such liabilities based on the minimum statutory withholding rates for income and payroll tax purposes that are applicable to such supplemental taxable income.

7. **Rights as Unit Holder.** Neither the Participant nor any person claiming under or through the Participant shall have any of the rights or privileges of a holder of Units in respect of any Units that may become deliverable hereunder unless and until certificates representing such Units shall have been issued or recorded in book entry form on the records of the Partnership or its transfer agents or registrars, and delivered in certificate or book entry form to the Participant or any person claiming under or through the Participant.

8. **Non-Transferability.** Neither the RPUs nor the DERs may be sold, pledged, assigned or transferred in any manner other than by will or the laws of descent and distribution. Neither the RPUs, DERs nor any interest or right therein shall be liable for the debts, contracts or engagements of the Participant or his or her successors in interest or shall be subject to disposition by transfer, alienation, anticipation, pledge, encumbrance, assignment or any other means whether such disposition be voluntary or involuntary or by operation of law by judgment, levy, attachment, garnishment or any other legal or equitable proceedings (including bankruptcy), and any attempted disposition thereof shall be null and void and of no effect, except to the extent that such disposition is permitted by the preceding sentence.

9. **Distribution of Units.** The Units issued pursuant to this Agreement shall be held in book entry form and no certificates shall be issued therefor; provided, that certificates may be issued representing such Units at the request of the Participant and in accordance with the Partnership’s governing documents, as amended and supplemented from time to time. Notwithstanding anything herein to the contrary, (a) no payment shall be made under this Agreement in the form of Units unless such Units issuable upon such payment are then registered under the Securities Act of 1933, as amended (the “Securities Act”) or, if such Units are not then so registered, the Company has determined that such payment and issuance would be exempt from the registration requirements of the Securities Act, and (b) the Partnership shall not be required to issue or deliver any Units (whether in certificated or book-entry form) pursuant to this Agreement unless (i) such issuance and delivery are in compliance with all applicable laws and regulations and, if applicable, the requirements of any exchange on which the Units are listed or traded, and (ii) any consent or approval of any governmental or regulatory authority necessary or desirable as a condition to such issuance and delivery to the Participant (or his or her estate) has been obtained. Any certificates delivered pursuant to this Agreement shall be subject to any stop-transfer orders and other restrictions as the Company deems necessary or advisable to comply with federal, state
or local securities or other laws, rules and regulations and the rules of any national securities exchange or automated quotation system on which the Units are listed, quoted or traded. The Company may place legends on any certificate to reference restrictions applicable to the Units. In addition to the terms and conditions provided herein, the Company may require that the Participant make such covenants, agreements, and representations as the Company, in its sole discretion, deems advisable in order to comply with any such laws, regulations or requirements. The Company shall have the right to require the Participant to comply with any timing or other restrictions with respect to the settlement of any RPUs pursuant to this Agreement, including a window-period limitation, as may be imposed in its discretion. No fractional Units shall be issued or delivered pursuant to the RPUs.

10. **Partnership Agreement.** Units issued upon payment of the RPUs shall be subject to the terms of the Plan and the terms of the Partnership Agreement. Upon the issuance of Units to the Participant, the Participant shall, automatically and without further action on his or her part, be deemed to be a party to, signatory of and bound by the Partnership Agreement.

11. **No Effect on Employment.** Nothing in this Agreement or in the Plan shall confer upon the Participant any right to serve or continue to serve as an Employee, Director or Consultant.

12. **Severability.** If any provision in this Agreement is held invalid or unenforceable, such provision will be severable from, and such invalidity or unenforceability will not be construed to have any effect on, the remaining provisions of this Agreement, which shall remain in full force and effect.

13. **Tax Consultation.** None of the Partnership, the Company or any of their Affiliates has made any warranty or representation to Participant with respect to the income tax consequences of the issuance of the RPUs, the Units or the transactions contemplated by this Agreement, and Participant is in no manner relying on such entities or their representatives for an assessment of such tax consequences. The Participant understands that the Participant may suffer adverse tax consequences in connection with the RPUs granted pursuant to this Agreement. The Participant represents that the Participant has consulted with any tax consultants that the Participant deems advisable in connection with the RPUs and that the Participant is not relying on the Partnership for tax advice.

14. **Amendments, Suspension and Termination.** To the extent permitted by the Plan, this Agreement may be wholly or partially amended or otherwise modified, suspended or terminated at any time or from time to time by the Committee. Except as provided in the preceding sentence, this Agreement cannot be modified, altered or amended, except by an agreement, in writing, signed by both the Partnership and the Participant.

15. **Conformity to Securities Laws.** The Participant acknowledges that the Plan and this Agreement are intended to conform to the extent necessary with all provisions of the Securities Act and the Exchange Act and any and all regulations and rules promulgated by the Securities and Exchange Commission thereunder, and all applicable state securities laws and regulations. Notwithstanding anything herein to the contrary, the Plan shall be administered, and the RPUs are granted, only in such a manner as to conform to such laws, rules and regulations. To the extent permitted by applicable law, the Plan and this Agreement shall be deemed amended to the extent necessary to conform to such laws, rules and regulations.
16. **Code Section 409A.** The RPUs and the amounts payable under this Agreement may constitute or provide for “nonqualified deferred compensation” which is intended to comply with the requirements of Code Section 409A. To the extent that the Committee determines that any RPUs or any amounts payable under this Agreement may not be compliant with Code Section 409A, the Committee and the Participant shall cooperate and work together in good faith to timely amend this Agreement in a manner intended to comply with the requirements of Code Section 409A or an exemption therefrom (including amendments with retroactive effect), or take any other actions as they deem necessary or appropriate to (a) exempt the RPUs from Code Section 409A and/or preserve the intended tax treatment of the benefits provided with respect to the RPUs, or (b) comply with the requirements of Code Section 409A. To the extent applicable, this Agreement shall be interpreted in accordance with the provisions of Code Section 409A.

17. **Adjustments.** The Participant acknowledges that the RPUs are subject to modification and termination in certain events as provided in this Agreement and Section 7 of the Plan.

18. **Successors and Assigns.** The Partnership may assign any of its rights under this Agreement to single or multiple assignees, and this Agreement shall inure to the benefit of the successors and assigns of the Partnership. Subject to the restrictions on transfer contained herein, this Agreement shall be binding upon the Participant and his or her heirs, executors, administrators, successors and assigns.

19. **Governing Law.** The laws of the State of Delaware shall govern the interpretation, validity, administration, enforcement and performance of the terms of this Agreement regardless of the law that might be applied under principles of conflicts of laws.

20. **Captions.** Captions provided herein are for convenience only and are not to serve as a basis for interpretation or construction of this Agreement.

[ Signature page follows ]
The Participant’s signature below indicates the Participant’s agreement with and understanding that this award is subject to all of the terms and conditions contained in the Plan and in this Agreement, and that, in the event that there are any inconsistencies between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall control, except with respect to the definition of “Change of Control” contained in this Agreement, which definition shall control over the one in the Plan. The Participant further acknowledges that the Participant has read and understands the Plan and this Agreement, which contains the specific terms and conditions of this grant of RPUs. The Participant hereby agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee upon any questions arising under the Plan or this Agreement.

PARTICIPANT: ____________________________

Name:

BREITBURN GP, LLC

By: ____________________________

Name: Halbert S. Washburn
Title: Chief Executive Officer
Pursuant to this Restricted Phantom Unit Agreement (the “Agreement”), BreitBurn GP, LLC (the “Company”), as the general partner of BreitBurn Energy Partners L.P., a Delaware limited partnership (the “Partnership”), hereby grants to [Name] (the “Participant”) the following award of Restricted Phantom Units (“RPUs”), pursuant and subject to the terms and conditions of this Agreement and the Partnership’s First Amended and Restated 2006 Long-Term Incentive Plan (the “Plan”), the terms and conditions of which are hereby incorporated into this Agreement by reference. Each RPU shall constitute a Phantom Unit under the terms of the Plan and is hereby granted in tandem with a corresponding DER, as further detailed in Section 3 below. Except as otherwise expressly provided herein, all capitalized terms used in this Agreement, but not defined, shall have the meanings provided in the Plan.

GRANT NOTICE

Subject to the terms and conditions of this Agreement, the principal features of this Award are as follows:

Number of RPUs : _______

Grant Date : January [ ], 2014

Vesting of RPUs : One-third of the RPUs (rounded down to the next whole number of units, except in the case of the final vesting date) shall vest on each of January 1, 2015, January 1, 2016 and January 1, 2017 (each, a “Vesting Date”), subject to the Participant’s continued service as a Director through each such date. In addition, the RPUs shall be subject to accelerated vesting as set forth in Section 4 below.

Termination of RPUs : In the event of the Participant’s “separation from service” from the Company, within the meaning of Code Section 409A(a)(2)(A)(i) (“Separation from Service”) for any reason other than those set forth in Section 4 of the “Terms and Conditions of Restricted Phantom Units,” all RPUs that have not vested prior to or in connection with such Separation from Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor.

Payment of RPUs : Vested RPUs shall be paid to the Participant in the form of Units as set forth in Section 5 below.

DERs : Each RPU granted under this Agreement shall be issued in tandem with a corresponding DER, which shall entitle the Participant to receive payments in an amount equal to Partnership distributions in accordance with Section 3 of this Agreement.

TERMS AND CONDITIONS OF RESTRICTED PHANTOM UNITS

1. Grant. The Partnership hereby grants to the Participant, as of the Grant Date, an award of ___ RPUs, subject to all of the terms and conditions contained in this Agreement and the Plan.

2. RPUs. Subject to Section 4 below, each RPU that vests shall represent the right to receive payment, in accordance with Section 5 below, in the form of one Unit. Unless and until an RPU vests, the Participant will have no right to payment in respect of any such RPU. Prior to actual payment in respect of any vested RPU, such RPU will represent an unsecured obligation of the Partnership, payable (if at all) only from the general assets of the Partnership.

3. Grant of Tandem DER. Each RPU granted hereunder is hereby granted in tandem with a corresponding DER, which DER shall remain outstanding from the Grant Date until the earlier of the payment or forfeiture of the RPU to
which it corresponds. Pursuant to each DER, the Participant shall be entitled to receive payments in an amount equal to any distributions made by the Partnership in respect of the underlying Unit, so long as such DER is outstanding as of the record date set by the Board of Directors of the Company for such distribution to be paid to the holders of Units. Such payments shall be made no later than 15 days after the date of any applicable distribution paid to the holders of Units by the Partnership, but in no event later than the last day of the applicable two and one-half (2-1/2) month “short-term deferral” period with respect to such DER payment, within the meaning of Treasury Regulation Section 1.409A-1(b)(4). DERs shall not entitle the Participant to any payments relating to distributions occurring after the earlier to occur of the applicable RPU payment date or the forfeiture of the RPU underlying such DER. The DERs and any amounts that may become distributable in respect thereof shall be treated separately from the RPUs and the rights arising in connection therewith for purposes of the designation of time and form of payments required by Code Section 409A.

4. Vesting and Termination.

(a) General. The RPUs shall vest in such amounts and at such times as are set forth in the Grant Notice above, provided, that the RPUs shall vest in full upon any earlier occurrence of (a) the Participant’s Separation from Service due to the Participant’s death or a disability that would entitle the Participant to benefits under the Company’s (or an Affiliate’s) long-term disability plan, if the Participant were eligible to participate in such plan, or (b) a Change of Control and, in any case, shall be subject to the payment provisions contained in Section 5 below.

No portion of the RPUs which has not become vested at the date of the Participant’s Separation from Service shall thereafter become vested. In the event of the Participant’s Separation from Service for any reason other than as set forth in (a) and (b) of this Section, all RPUs that have not vested prior to or in connection with such Separation from Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor.

(b) Change of Control Definition. “Change of Control” means, and shall be deemed to have occurred upon one or more of the following events:

(i) any “person” or “group” within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an Affiliate of the Company, shall become the beneficial owner, directly or indirectly, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests or of a controlling interest in BreitBurn Management Company, LLC, the Company or the Partnership;

(ii) the limited partners of the Partnership approve, in one or a series of transactions, a plan of complete liquidation of the Partnership;

(iii) the sale or other disposition by either the Company or the Partnership of all or substantially all of its assets in one or more transactions to any Person other than the Company or an Affiliate of the Company;

(iv) a transaction resulting in a Person other than the Company or an Affiliate of the Company being the general partner of the Partnership; or

(v) any time at which individuals who, as of the Grant Date, constitute the board of directors of the Company (the “Incumbent Board”) cease for any reason to constitute a majority of the Board; provided, however, that any individual becoming a director subsequent to the Grant Date whose election, or nomination for election by the Partnership’s unitholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board will be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as the result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Incumbent Board.

5. Payment of RPUs; Issuance of Units.

(a) General. Unpaid, vested RPUs shall be paid to the Participant in the form of Units in a lump-sum during the sixty-day period commencing with the earliest to occur of the following dates (the “Payment Date”): (i) the applicable Vesting Date specified in the Grant Notice; or (ii) subject to Section 5(b) below, the date of Participant’s Separation from Service. Payments of any RPUs that vest in accordance herewith shall be made to the Participant (or in
the event of the Participant’s death, to the Participant’s estate) in whole Units in accordance with this Section 5.

(b) Potential Six-Month Delay. Notwithstanding anything to the contrary in this Agreement, no amounts payable under this Agreement shall be paid to the Participant during the six-month period following the Participant’s Separation from Service to the extent that the Company reasonably determines that paying such amounts prior to the expiration of such six-month period would result in a prohibited distribution under Section 409A(a)(2)(b)(i) of the Code. If the payment of any such amounts is delayed as a result of the previous sentence, then on the first business day following the end of the applicable six-month period (or such earlier date upon which such amounts can be paid under Code Section 409A without resulting in a prohibited distribution, including as a result of the Participant’s death), such amounts shall be paid to the Participant.

6. Tax Withholding. The Company and/or its Affiliates shall have the authority and the right to deduct or withhold, or to require the Participant to remit to the Company and/or its Affiliates, an amount sufficient to satisfy all applicable federal, state and local taxes (including the Participant’s employment tax obligations) required by law to be withheld with respect to any taxable event arising in connection with the RPUs. Without limiting the generality of Section 8(b) of the Plan, to the extent that such obligation arises at the time that the RPUs are paid to the Participant in Units, the Company and/or its Affiliates may withhold Units otherwise issuable in respect of such RPUs having a Fair Market Value equal to the sums required to be withheld in satisfaction of the foregoing requirement. Notwithstanding any other provision of the Plan or this Agreement, the number of Units which may be so withheld in order to satisfy the Participant’s income and payroll tax liabilities with respect to the issuance, vesting or payment of the RPUs shall be limited to the number of Units which have a Fair Market Value on the date of withholding equal to the aggregate amount of such liabilities based on the minimum statutory withholding rates for income and payroll tax purposes that are applicable to such supplemental taxable income.

7. Rights as Unit Holder. Neither the Participant nor any person claiming under or through the Participant shall have any of the rights or privileges of a holder of Units in respect of any Units that may become deliverable hereunder unless and until certificates representing such Units shall have been issued or recorded in book entry form on the records of the Partnership or its transfer agents or registrars, and delivered in certificate or book entry form to the Participant or any person claiming under or through the Participant.

8. Non-Transferability. RPUs may not be sold, pledged, assigned or transferred in any manner other than by will or the laws of descent and distribution. Neither the RPUs nor any interest or right therein shall be liable for the debts, contracts or engagements of the Participant or his or her successors in interest or shall be subject to disposition by transfer, alienation, anticipation, pledge, encumbrance, assignment or any other means whether such disposition be voluntary or involuntary or by operation of law by judgment, levy, attachment, garnishment or any other legal or equitable proceedings (including bankruptcy), and any attempted disposition thereof shall be null and void and of no effect, except to the extent that such disposition is permitted by the preceding sentence.

9. Distribution of Units. The Units issued pursuant to this Agreement shall be held in book entry form and no certificates shall be issued therefor; provided, that certificates may be issued representing such Units at the request of the Participant and in accordance with the Partnership’s governing documents, as amended and supplemented from time to time. Notwithstanding anything herein to the contrary, (a) no payment shall be made under this Agreement in the form of Units unless such Units issuable upon such payment are then registered under the Securities Act of 1933, as amended (the “Securities Act”) or, if such Units are not then so registered, the Company has determined that such payment and issuance would be exempt from the registration requirements of the Securities Act, and (b) the Partnership shall not be required to issue or deliver any Units (whether in certificated or book-entry form) pursuant to this Agreement unless (i) such issuance and delivery are in compliance with all applicable laws and regulations and, if applicable, the requirements of any exchange on which the Units are listed or traded, and (ii) any consent or approval of any governmental or regulatory authority necessary or desirable as a condition to such issuance and delivery to the Participant (or his or her estate) has been obtained. Any certificates delivered pursuant to this Agreement shall be subject to any stop-transfer orders and other restrictions as the Company deems necessary or advisable to comply with federal, state or local securities or other laws, rules and regulations and the rules of any national securities exchange or automated quotation system on which the Units are listed, quoted or traded. The Company may place legends on any certificate to reference restrictions applicable to the Units. In addition to the terms and conditions provided herein, the Company may require that the Participant make such covenants, agreements and representations as the Company, in its sole discretion, deems advisable in order to comply with any such laws, regulations or requirements. The Company shall have the right to require the Participant to comply with any timing or other restrictions with respect to the settlement of any RPUs pursuant to this Agreement, including a window-period limitation, as may be imposed in its discretion. No fractional Units shall be issued or delivered pursuant to the RPUs.
10. **Partnership Agreement.** Units issued upon payment of the RPUs shall be subject to the terms of the Plan and the terms of the Partnership Agreement. Upon the issuance of Units to the Participant, the Participant shall, automatically and without further action on his or her part, be deemed to be a party to, signatory of and bound by the Partnership Agreement.

11. **No Effect on Service.** Nothing in this Agreement or in the Plan shall confer upon the Participant any right to serve or continue to serve as a Director.

12. **Severability.** If any provision in this Agreement is held invalid or unenforceable, such provision will be severable from, and such invalidity or unenforceability will not be construed to have any effect on, the remaining provisions of this Agreement, which shall remain in full force and effect.

13. **Tax Consultation.** None of the Partnership, the Company or any of their Affiliates has made any warranty or representation to Participant with respect to the income tax consequences of the issuance of the RPUs, the Units or the transactions contemplated by this Agreement, and Participant is in no manner relying on such entities or their representatives for an assessment of such tax consequences. The Participant understands that the Participant may suffer adverse tax consequences in connection with the RPUs granted pursuant to this Agreement. The Participant represents that the Participant has consulted with any tax consultants that the Participant deems advisable in connection with the RPUs and that the Participant is not relying on the Partnership for tax advice.

14. **Amendments, Suspension and Termination.** To the extent permitted by the Plan, this Agreement may be wholly or partially amended or otherwise modified, suspended or terminated at any time or from time to time by the Committee. Except as provided in the preceding sentence, this Agreement cannot be modified, altered or amended, except by an agreement, in writing, signed by both the Partnership and the Participant.

15. **Conformity to Securities Laws.** The Participant acknowledges that the Plan and this Agreement are intended to conform to the extent necessary with all provisions of the Securities Act and the Exchange Act and any and all regulations and rules promulgated by the Securities and Exchange Commission thereunder, and all applicable state securities laws and regulations. Notwithstanding anything herein to the contrary, the Plan shall be administered, and the RPUs are granted, only in such a manner as to conform to such laws, rules and regulations. To the extent permitted by applicable law, the Plan and this Agreement shall be deemed amended to the extent necessary to conform to such laws, rules and regulations.

16. **Code Section 409A.** The RPUs and the amounts payable under this Agreement may constitute or provide for “nonqualified deferred compensation” which is intended to comply with the requirements of Code Section 409A. To the extent that the Committee determines that any RPUs or any amounts payable under this Agreement may not be compliant with Code Section 409A, the Committee and the Participant shall cooperate and work together in good faith to timely amend this Agreement in a manner intended to comply with the requirements of Code Section 409A or an exemption therefrom (including amendments with retroactive effect), or take any other actions as they deem necessary or appropriate to (a) exempt the RPUs from Code Section 409A and/or preserve the intended tax treatment of the benefits provided with respect to the RPUs, or (b) comply with the requirements of Code Section 409A. To the extent applicable, this Agreement shall be interpreted in accordance with the provisions of Code Section 409A.

17. **Adjustments.** The Participant acknowledges that the RPUs are subject to modification and termination in certain events as provided in this Agreement and Section 7 of the Plan.

18. **Successors and Assigns.** The Partnership may assign any of its rights under this Agreement to single or multiple assignees, and this Agreement shall inure to the benefit of the successors and assigns of the Partnership. Subject to the restrictions on transfer contained herein, this Agreement shall be binding upon the Participant and his or her heirs, executors, administrators, successors and assigns.

19. **Governing Law.** The laws of the State of Delaware shall govern the interpretation, validity, administration, enforcement and performance of the terms of this Agreement regardless of the law that might be applied under principles of conflicts of laws.

20. **Captions.** Captions provided herein are for convenience only and are not to serve as a basis for interpretation or construction of this Agreement.

[Signature page follows]
The Participant’s signature below indicates the Participant’s agreement with and understanding that this award is subject to all of the terms and conditions contained in the Plan and in this Agreement, and that, in the event that there are any inconsistencies between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall control, except with respect to the definition of “Change of Control” contained in this Agreement, which definition shall control over the one in the Plan. The Participant further acknowledges that the Participant has read and understands the Plan and this Agreement, which contains the specific terms and conditions of this grant of RPUs. The Participant hereby agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee upon any questions arising under the Plan or this Agreement.

PARTICIPANT:  
[Name]

BREITBURN GP, LLC

By: _______________________
Name: Halbert S. Washburn
Title: Chief Executive Officer
Pursuant to this Restricted Phantom Unit Agreement (the “Agreement”), BreitBurn GP, LLC (the “Company”), as the general partner of BreitBurn Energy Partners L.P., a Delaware limited partnership (the “Partnership”), hereby grants to Halbert S. Washburn (the “Participant”) the following award of Restricted Phantom Units (“RPUs”), pursuant and subject to the terms and conditions of this Agreement, the Deferral Election form made by the Participant with respect to the RPUs, dated December 26, 2013, and the First Amended and Restated Partnership 2006 Long-Term Incentive Plan (the “Plan”), the terms and conditions of which are hereby incorporated into this Agreement by reference. Each RPU shall constitute a Phantom Unit under the terms of the Plan and is hereby granted in tandem with a corresponding DER, as further detailed in Section 3 below. Except as otherwise expressly provided herein, all capitalized terms used in this Agreement, but not defined, shall have the meanings provided in the Plan. For purposes of this Agreement, the terms “Employer,” “Cause,” “Good Reason” and “Disability” shall have the meanings ascribed to such terms in the Employment Agreement between the Employer and the Participant, dated December 30, 2010 (the “Employment Agreement”).

GRANT NOTICE

Subject to the terms and conditions of this Agreement, the principal features of this Award are as follows:

Number of RPUs: ###

Grant Date: [_____] , 2014

Vesting of RPUs: One–third of the RPUs (rounded down to the next whole number of units, except in the case of the final vesting date) shall vest on each of December 28, 2014, December 28, 2015 and December 28, 2016, subject to the Participant’s continued service as an Employee, Director or Consultant through each such date. In addition, the RPUs shall be subject to accelerated vesting as set forth in Section 4 below.

Termination of RPUs: In the event of the Participant’s Separation from Service (as defined in the Employment Agreement) for any reason other than those set forth in Section 4 of the “Terms and Conditions of Restricted Phantom Units,” all RPUs that have not vested prior to or in connection with such Separation from Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor.

Payment of RPUs: Vested RPUs shall be paid to the Participant in the form of Units as set forth in Section 5 below.

DERs: Each RPU granted under this Agreement shall be issued in tandem with a corresponding DER, which shall entitle the Participant to receive an amount equal to any Partnership distributions and which shall be credited to the Participant in the form of additional RPUs in accordance with Section 3 of this Agreement.
TERMS AND CONDITIONS OF RESTRICTED PHANTOM UNITS

1. Grant. The Partnership hereby grants to the Participant, as of the Grant Date, an award of ### RPUs, subject to all of the terms and conditions contained in this Agreement and the Plan.

2. RPUs. Subject to Section 4 below, each RPU that vests shall represent the right to receive payment, in accordance with Section 5 below, in the form of one Unit. Unless and until an RPU vests, the Participant will have no right to payment in respect of any such RPU. Prior to actual payment in respect of any vested RPU, such RPU will represent an unsecured obligation of the Partnership, payable (if at all) only from the general assets of the Partnership.

3. Grant of Tandem DER. Each RPU granted or credited hereunder shall be issued in tandem with a corresponding DER, which DER shall remain outstanding from the Grant Date until the earlier of the payment or forfeiture of the RPU to which it corresponds. Pursuant to each DER, the Participant shall be entitled to receive an amount equal to any distributions made by the Partnership in respect of the underlying Unit, if any, beginning with the distribution paid in January 2014, payable in the same amounts as distributions paid to the holders of Units and credited in the form of additional RPUs as set forth in the following sentence, so long as such DER is outstanding as of the record date set by the Board of Directors of the Company for such distribution to be paid to the holders of Units, except with respect to the distribution paid in January 2014. All such DERs shall be credited to the Participant in the form of additional RPUs as of the date of payment of any such distribution based on the Fair Market Value of a Unit on such date, except with respect to the credit for the January 2014 distribution which shall be credited at the same time as the credit for the February 2014 distribution. Each additional RPU which results from such crediting of DERs granted hereunder shall be subject to the same vesting, forfeiture, payment or distribution, adjustment and other provisions which apply to the underlying RPU to which such additional RPU relates. DERs shall not entitle the Participant to any amounts relating to distributions occurring after the earlier to occur of the applicable RPU payment date or the forfeiture of the RPU underlying such DER. The DERs and any amounts that may become distributable in respect thereof shall be treated separately from the RPUs and the rights arising in connection therewith for purposes of the designation of time and form of payments required by Code Section 409A.

4. Vesting and Termination.

   (a) General. The RPUs shall vest in such amounts and at such times as are set forth in the Grant Notice above, provided, that the RPUs shall vest in full upon any earlier occurrence of (a) the Participant’s Separation from Service without Cause, for Good Reason or due to the Participant’s death or Disability, or (b) a Change of Control and, in any case, shall be subject to the payment provisions contained in Section 5 below. No portion of the RPUs which has not become vested at the date of the Participant’s Separation from Service shall thereafter become vested. In the event of the Participant’s Separation from Service for any reason other than as set forth in (a) of this Section, all RPUs that have not vested prior to or in connection with such Separation from Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor.

   (b) Change of Control Definition. “Change of Control” means, and shall be deemed to have occurred upon one or more of the following events:
Deferred Payment Award

(i) any “person” or “group” within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an Affiliate of the Company, shall become the beneficial owner, directly or indirectly, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests or of a controlling interest in BreitBurn Management Company, LLC, the Company or the Partnership;

(ii) the limited partners of the Partnership approve, in one or a series of transactions, a plan of complete liquidation of the Partnership;

(iii) the sale or other disposition by either the Company or the Partnership of all or substantially all of its assets in one or more transactions to any Person other than the Company or an Affiliate of the Company;

(iv) a transaction resulting in a Person other than the Company or an Affiliate of the Company being the general partner of the Partnership; or

(v) any time at which individuals who, as of the Grant Date, constitute the board of directors of the Company (the “Incumbent Board”) cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the Grant Date whose election, or nomination for election by the Partnership’s unitholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board will be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as the result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Incumbent Board.

5. Payment of RPUs; Issuance of Units .

(a) General . Unpaid, vested RPUs shall be paid to the Participant in the form of Units in a lump-sum during the sixty-day period commencing with the earliest to occur of the following dates (the “ Payment Date ”) (with the exact date of payment determined by the Company in its sole discretion):

(i) December 28, 2025;

(ii) the date of the Participant’s Separation from Service; and

(iii) the date of the Participant’s death.

Payments of any RPUs that vest in accordance herewith shall be made to the Participant (or in the event of the Participant’s death, to the Participant’s estate) in whole Units in accordance with this Section 5.

(b) Potential Six-Month Delay . Notwithstanding anything to the contrary in this Agreement, no amounts payable under this Agreement shall be paid to the Participant prior to the expiration of the six-month period following his Separation from Service to the extent that the Company reasonably determines that paying such amounts prior to the expiration of such six-month
6. **Tax Withholding.** The Company and/or its Affiliates shall have the authority and the right to deduct or withhold, or to require the Participant to remit to the Company and/or its Affiliates, an amount sufficient to satisfy all applicable federal, state and local taxes (including the Participant’s employment tax obligations) required by law to be withheld with respect to any taxable event arising in connection with the RPUs. Without limiting the generality of Section 8(b) of the Plan, to the extent that such obligation arises at the time that the RPUs vest or are paid to the Participant in Units, the Company and/or its Affiliates may withhold Units otherwise issuable in respect of such RPUs having a Fair Market Value equal to the sums required to be withheld in satisfaction of the foregoing requirement. Notwithstanding any other provision of the Plan or this Agreement, the number of Units which may be so withheld in order to satisfy the Participant’s income and payroll tax liabilities with respect to the issuance, vesting or payment of the RPUs shall be limited to the number of Units which have a Fair Market Value on the date of withholding equal to the aggregate amount of such liabilities based on the minimum statutory withholding rates for income and payroll tax purposes that are applicable to such supplemental taxable income.

7. **Rights as Unit Holder.** Neither the Participant nor any person claiming under or through the Participant shall have any of the rights or privileges of a holder of Units in respect of any Units that may become deliverable hereunder unless and until certificates representing such Units shall have been issued or recorded in book entry form on the records of the Partnership or its transfer agents or registrars, and delivered in certificate or book entry form to the Participant or any person claiming under or through the Participant.

8. **Non-Transferability.** Neither the RPUs nor the DERs may be sold, pledged, assigned or transferred in any manner other than by will or the laws of descent and distribution. Neither the RPUs, DERs nor any interest or right therein shall be liable for the debts, contracts or engagements of the Participant or his or her successors in interest or shall be subject to disposition by transfer, alienation, anticipation, pledge, encumbrance, assignment or any other means whether such disposition be voluntary or involuntary or by operation of law by judgment, levy, attachment, garnishment or any other legal or equitable proceedings (including bankruptcy), and any attempted disposition thereof shall be null and void and of no effect, except to the extent that such disposition is permitted by the preceding sentence.

9. **Distribution of Units.** The Units issued pursuant to this Agreement shall be held in book entry form and no certificates shall be issued therefor; provided, that certificates may be issued representing such Units at the request of the Participant and in accordance with the Partnership’s governing documents, as amended and supplemented from time to time. Notwithstanding anything herein to the contrary, (a) no payment shall be made under this Agreement in the form of Units unless such Units issuable upon such payment are then registered under the Securities Act of 1933, as amended (the “Securities Act”) or, if such Units are not then so registered, the Company has determined that such payment and issuance would be exempt from the registration requirements of the Securities Act, and (b) the Partnership shall not be required to issue or deliver any Units (whether in certificated or book-entry form) pursuant to this Agreement.

Deferred Payment Award

Deferred Payment Award period would result in a prohibited distribution under Section 409A(a)(2)(B)(i) of the Code. If the payment of any such amounts is delayed as a result of the previous sentence, then on the first business day following the end of the applicable six-month period (or such earlier date upon which such amounts can be paid under Code Section 409A without resulting in a prohibited distribution, including as a result of the Participant’s death), such amounts shall be paid to the Participant.

Deferred Payment Award
unless (i) such issuance and delivery are in compliance with all applicable laws and regulations and, if applicable, the requirements of any exchange on which the Units are listed or traded, and (ii) any consent or approval of any governmental or regulatory authority necessary or desirable as a condition to such issuance and delivery to the Participant (or his or her estate) has been obtained. Any certificates delivered pursuant to this Agreement shall be subject to any stop-transfer orders and other restrictions as the Company deems necessary or advisable to comply with federal, state or local securities or other laws, rules and regulations and the rules of any national securities exchange or automated quotation system on which the Units are listed, quoted or traded. The Company may place legends on any certificate to reference restrictions applicable to the Units. In addition to the terms and conditions provided herein, the Company may require that the Participant make such covenants, agreements, and representations as the Company, in its sole discretion, deems advisable in order to comply with any such laws, regulations or requirements. The Company shall have the right to require the Participant to comply with any timing or other restrictions with respect to the settlement of any RPUs pursuant to this Agreement, including a window-period limitation, as may be imposed in its discretion. No fractional Units shall be issued or delivered pursuant to the RPUs.

10. **Partnership Agreement**. Units issued upon payment of the RPUs shall be subject to the terms of the Plan and the terms of the Partnership Agreement. Upon the issuance of Units to the Participant, the Participant shall, automatically and without further action on his or her part, be deemed to be a party to, signatory of and bound by the Partnership Agreement.

11. **No Effect on Employment**. Nothing in this Agreement or in the Plan shall confer upon the Participant any right to serve or continue to serve as an Employee, Director or Consultant.

12. **Severability**. If any provision in this Agreement is held invalid or unenforceable, such provision will be severable from, and such invalidity or unenforceability will not be construed to have any effect on, the remaining provisions of this Agreement, which shall remain in full force and effect.

13. **Tax Consultation**. None of the Partnership, the Company or any of their Affiliates has made any warranty or representation to Participant with respect to the income tax consequences of the issuance of the RPUs, the Units or the transactions contemplated by this Agreement, and Participant is in no manner relying on such entities or their representatives for an assessment of such tax consequences. The Participant understands that the Participant may suffer adverse tax consequences in connection with the RPUs granted pursuant to this Agreement. The Participant represents that the Participant has consulted with any tax consultants that the Participant deems advisable in connection with the RPUs and that the Participant is not relying on the Partnership for tax advice.

14. **Amendments, Suspension and Termination**. To the extent permitted by the Plan, this Agreement may be wholly or partially amended or otherwise modified, suspended or terminated at any time or from time to time by the Committee. Except as provided in the preceding sentence, this Agreement cannot be modified, altered or amended, except by an agreement, in writing, signed by both the Partnership and the Participant.

15. **Conformity to Securities Laws**. The Participant acknowledges that the Plan and this Agreement are intended to conform to the extent necessary with all provisions of the Securities
Act and the Exchange Act and any and all regulations and rules promulgated by the Securities and Exchange Commission thereunder, and all applicable state securities laws and regulations. Notwithstanding anything herein to the contrary, the Plan shall be administered, and the RPUs are granted, only in such a manner as to conform to such laws, rules and regulations. To the extent permitted by applicable law, the Plan and this Agreement shall be deemed amended to the extent necessary to conform to such laws, rules and regulations.

16. **Code Section 409A**. The RPUs and the amounts payable under this Agreement may constitute or provide for “nonqualified deferred compensation” which is intended to comply with the requirements of Code Section 409A. To the extent that the Committee determines that any RPUs or any amounts payable under this Agreement may not be compliant with Code Section 409A, the Committee and the Participant shall cooperate and work together in good faith to timely amend this Agreement in a manner intended to comply with the requirements of Code Section 409A or an exemption therefrom (including amendments with retroactive effect), or take any other actions as they deem necessary or appropriate to (a) exempt the RPUs from Code Section 409A and/or preserve the intended tax treatment of the benefits provided with respect to the RPUs, or (b) comply with the requirements of Code Section 409A. To the extent applicable, this Agreement shall be interpreted in accordance with the provisions of Code Section 409A.

17. **Adjustments**. The Participant acknowledges that the RPUs are subject to modification and termination in certain events as provided in this Agreement and Section 7 of the Plan.

18. **Successors and Assigns**. The Partnership may assign any of its rights under this Agreement to single or multiple assignees, and this Agreement shall inure to the benefit of the successors and assigns of the Partnership. Subject to the restrictions on transfer contained herein, this Agreement shall be binding upon the Participant and his or her heirs, executors, administrators, successors and assigns.

19. **Governing Law**. The laws of the State of Delaware shall govern the interpretation, validity, administration, enforcement and performance of the terms of this Agreement regardless of the law that might be applied under principles of conflicts of laws.

20. **Captions**. Captions provided herein are for convenience only and are not to serve as a basis for interpretation or construction of this Agreement.

[ Signature page follows ]
The Participant’s signature below indicates the Participant’s agreement with and understanding that this award is subject to all of the terms and conditions contained in the Plan and in this Agreement, and that, in the event that there are any inconsistencies between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall control, except with respect to the definition of “Change of Control” contained in this Agreement, which definition shall control over the one in the Plan. The Participant further acknowledges that the Participant has read and understands the Plan and this Agreement, which contains the specific terms and conditions of this grant of RPUs. The Participant hereby agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee upon any questions arising under the Plan or this Agreement.

PARTICIPANT:  

Halbert S. Washburn

BREITBURN GP, LLC

By: _______________.
Name: 
Title: 
## SUBSIDIARIES OF BREITBURN ENERGY PARTNERS L.P.

<table>
<thead>
<tr>
<th>Name</th>
<th>Jurisdiction</th>
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<tbody>
<tr>
<td>BreitBurn Operating GP, LLC</td>
<td>Delaware</td>
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<tr>
<td>BreitBurn Operating L.P.</td>
<td>Delaware</td>
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<tr>
<td>Alamitos Company</td>
<td>California</td>
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<tr>
<td>BreitBurn Florida LLC</td>
<td>Delaware</td>
</tr>
<tr>
<td>BreitBurn Fulton LLC</td>
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</tr>
<tr>
<td>GTG Pipeline LLC</td>
<td>Virginia</td>
</tr>
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<td>Mercury Michigan Company, LLC</td>
<td>Michigan</td>
</tr>
<tr>
<td>Phoenix Production Company</td>
<td>Wyoming</td>
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<tr>
<td>BreitBurn Transpetco LP LLC</td>
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<tr>
<td>BreitBurn Transpetco GP LLC</td>
<td>Delaware</td>
</tr>
<tr>
<td>BreitBurn Transpetco Pipeline</td>
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<tr>
<td>BreitBurn Oklahoma LLC</td>
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<tr>
<td>Terra Energy Company LLC</td>
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<td>Terra Pipeline Company LLC</td>
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<tr>
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</tr>
<tr>
<td>BreitBurn GP, LLC</td>
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</tr>
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<td>BreitBurn Management Company, LLC</td>
<td>Delaware</td>
</tr>
<tr>
<td>BreitBurn Finance Corporation</td>
<td>Delaware</td>
</tr>
<tr>
<td>BreitBurn Collingwood Utica LLC</td>
<td>Delaware</td>
</tr>
</tbody>
</table>
CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-181531 and 333-193206) and the Registration Statements on Form S-8 (No. 333-181526 and No. 333-149190) of BreitBurn Energy Partners L.P. of our report dated February 27, 2014 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 28, 2014
CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the inclusion or incorporation by reference in the Registration Statements on Form S-3 (No. 333-181531 and 333-193206), the Registration Statements on Form S-8 (No. 333-181526 and No. 333-149190) and the 2013 Annual Report on Form 10-K of BreitBurn Energy Partners L.P. of information from our firm's reserves report dated January 29, 2014, entitled *Estimates of Reserves and Future Revenue to the BreitBurn Operating L.P. Interest in Certain Oil and Gas Properties located in California, Florida, Texas, and Wyoming as of December 31, 2013*, and all references to our firm included in or made part of the BreitBurn Energy Partners L.P. 2013 Annual Report on Form 10-K.

Netherland, Sewell & Associates, Inc.

By: /s/ J. Carter Henson Jr.
J. Carter Henson, Jr. P.E.
Senior Vice President

Houston, Texas
February 28, 2014
CONSENT OF SCHLUMBERGER TECHNOLOGY CORPORATION

As independent petroleum engineers, PetroTechnical Services Division of Schlumberger Technology Corporation hereby consents to the inclusion or incorporation by reference in the Registration Statements on Form S-3 (No. 333-181531 and 333-193206), the Registration Statements on Form S-8 (No. 333-181526 and No. 333-149190) and the 2013 Annual Report on Form 10-K of BreitBurn Energy Partners L.P. of information from our firm's reserves report dated 31 January 2014 entitled Reserve and Economic Evaluation Of Proved Reserves Of Certain BreitBurn Management Company, LLC Illinois and Michigan Basin Oil And Gas Interests As Of 31 December 2013 Executive Summary, and all references to our firm included in or made part of the Annual Report on Form 10-K for the fiscal year ended 31 December 2013 of BreitBurn Energy Partners L.P.

SCHLUMBERGER TECHNOLOGY CORPORATION

/s/ Charles M. Boyer II
Pittsburgh Consulting Manager
Advisor Unconventional Reservoirs
Pittsburgh, Pennsylvania
28 February 2014
CONSENT OF CAWLEY, GILLESPIE & ASSOCIATES, INC.

As independent petroleum engineers, CAWLEY, GILLESPIE & ASSOCIATES, INC., we hereby consents to the inclusion or incorporation by reference in the Registration Statements on Form S-3 (No. 333-181531 and 333-193206), the Registration Statements on Form S-8 (No. 333-181526 and No. 333-149190) and the 2013 Annual Report on Form 10-K of BreitBurn Energy Partners L.P. of information from our firm's reserves report dated January 16, 2014 entitled Reserve Evaluation BreitBurn Management Company, LLC Interests Total Proved Reserves Postle Area As of December 31, 2013, and all references to our firm included in or made part of the Annual Report on Form 10-K for the fiscal year ended December 31, 2013 of BreitBurn Energy Partners L.P.

/s/ Cawley, Gillespie & Associates, Inc.
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693
February 28, 2014
I, Halbert S. Washburn, certify that:

1. I have reviewed this report on Form 10-K of BreitBurn Energy Partners L.P.;

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

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

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

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Halbert S. Washburn

Halbert S. Washburn

Chief Executive Officer of BreitBurn GP, LLC

Dated: February 28, 2014
I, James G. Jackson, certify that:

1. I have reviewed this report on Form 10-K of BreitBurn Energy Partners L.P.;

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

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

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

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ James G. Jackson

James G. Jackson

Chief Financial Officer of BreitBurn GP, LLC

Dated: February 28, 2014
CERTIFICATION PURSUANT TO SECTION 906

In connection with the Annual Report on Form 10-K for the year ended December 31, 2013 of BreitBurn Energy Partners L.P (the “Partnership”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Halbert S. Washburn, Chief Executive Officer of BreitBurn GP, LLC, the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Halbert S. Washburn
Halbert S. Washburn
Chief Executive Officer of BreitBurn GP, LLC

Dated: February 28, 2014
CERTIFICATION PURSUANT TO SECTION 906

In connection with the Annual Report on Form 10-K for the year ended December 31, 2013 of BreitBurn Energy Partners L.P (the “Partnership”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, James G. Jackson, Chief Financial Officer of BreitBurn GP, LLC, the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ James G. Jackson

James G. Jackson
Chief Executive Officer of BreitBurn GP, LLC

Dated: February 28, 2014
January 29, 2014

Mr. Mark L. Pease  
BreitBurn Management Company, LLC  
600 Travis Street, Suite 4800  
Houston, Texas 77002

Dear Mr. Pease:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2013, to the Breitburn Energy Company LP (BOLP) interest in certain oil and gas properties located in California, Florida, Texas, and Wyoming. We completed our evaluation on or about date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 52 percent of the proved reserves owned by BOLP. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for BOLP’s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the BOLP interest in these properties, as of December 31, 2013, to be:

<table>
<thead>
<tr>
<th>Category</th>
<th>Oil (MBBL)</th>
<th>NGL (MBBL)</th>
<th>Gas (MMCF)</th>
<th>Present Worth at 10%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Developed Producing</td>
<td>49,343.7</td>
<td>4,225.3</td>
<td>112,106.2</td>
<td>2,629,992.2</td>
</tr>
<tr>
<td>Proved Developed Non-Producing</td>
<td>8,903.1</td>
<td>1,263.5</td>
<td>10,571.3</td>
<td>419,092.3</td>
</tr>
<tr>
<td>Proved Undeveloped</td>
<td>14,554.6</td>
<td>4,265.9</td>
<td>44,505.3</td>
<td>662,567.2</td>
</tr>
<tr>
<td>Total Proved</td>
<td>72,801.4</td>
<td>9,754.7</td>
<td>167,182.8</td>
<td>3,711,651.5</td>
</tr>
</tbody>
</table>

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, estimates of proved developed non-producing and proved undeveloped reserves have only been included for properties that are economically producible based on the constant prices and costs discussed in subsequent paragraphs of this letter. Also as requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is BOLP’s share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for BOLP’s share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating costs.
expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. For oil and NGL volumes, the average ICE Brent crude price of $108.32 per barrel is used for the California properties and the average West Texas Intermediate spot price of $96.94 per barrel is used for all other properties. These average prices are adjusted for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $3.670 per MMBTU is adjusted for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $94.19 per barrel of oil, $26.48 per barrel of NGL, and $3.819 per MCF of gas.

Operating costs used in this report are based on operating expense records of BreitBurn Management Company, LLC (BreitBurn). For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and BreitBurn's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by BreitBurn and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are BreitBurn's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the BOLP interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on BOLP receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties.
inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from BOLP, BreitBurn, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By: C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ J. Carter Henson, Jr.        /s/ Mike K. Norton
By: J. Carter Henson, Jr., P.E. 73964        Mike K. Norton, P.G. 441
Senior Vice President        Senior Vice President

Date Signed: January 29, 2014    Date Signed: January 29, 2014

JCH:MSS

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.
DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4–10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC’s Compliance and Disclosure Interpretations.

(1) **Acquisition of properties.** Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers’ fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) **Analogous reservoir.** Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

- Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- Same environment of deposition;
- Similar geological structure; and
- Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) **Bitumen.** Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) **Condensate.** Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) **Deterministic estimate.** The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) **Developed oil and gas reserves.** Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

**Supplemental definitions from the 2007 Petroleum Resources Management System:**

**Developed Producing Reserves –** Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

**Developed Non-Producing Reserves –** Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) **Development costs.** Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorum taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) Exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

(15) Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a “terminal point”, which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(ii): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the
DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) Proved area. The part of a property to which proved reserves have been specifically attributed.

(22) Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) Proved properties. Properties with proved reserves.

(24) Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:
932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

1. **Standardized measure of discounted future net cash flows.** This amount is the future net cash flows less the computed discount.

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

(28) **Resources.** Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) **Service well.** A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) **Stratigraphic test well.** A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) **Undeveloped oil and gas reserves.** Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

   (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic productivity at greater distances.

   (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

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From the SEC’s Compliance and Disclosure Interpretations (October 26, 2009):
Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- The company’s level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
- The company’s historical record at completing development of comparable long-term projects;
- The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
- The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
- The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) **Unproved properties.** Properties with no proved reserves.
30 January 2014

Mark L. Pease  
BreitBurn Management Company, LLC  
600 Travis Street, Suite 4800  
Houston, Texas 77002

Dear Mr. Pease:

At the request of BreitBurn Management Company, LLC (BreitBurn), through their letter of engagement, PetroTechnical Services (PTS) Division of Schlumberger Technology Corporation has prepared a Proved (1P) reserve and economic evaluation of certain Indiana, Kentucky, and Michigan oil and gas interests as of 31 December 2013. This report was completed as of the date of this letter and has been prepared using constant prices and costs and conforms to our understanding of the U.S. Securities and Exchange Commission (SEC) guidelines and applicable financial accounting rules. All prices, costs, and cash flow estimates are expressed in U.S. dollars (US$). The reserves and future net revenue are to the interest of BreitBurn Operating L.P. (BOLP). It is our understanding that the properties evaluated by PTS comprise twenty-eight percent (28%) of BreitBurn's total proved reserves, and one-hundred percent (100%) of Breitburn's Indiana, Kentucky, and Michigan reserves. This report has been prepared for BreitBurn's use in filing with the Securities and Exchange Commission. We believe that the assumptions, data, methods, and procedures used in preparing this report are appropriate for the purpose of this report. The Lead Evaluator for this evaluation was Charles M. Boyer II, PG, CPG, and his qualifications, independence, objectivity, and confidentiality meet the requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Unescalated prices and costs were used for all properties contained in this evaluation.

The results of the Proved reserve evaluation are summarized in Table 1. Only proved non-producing and proved undeveloped reserves that have a positive 10 percent discounted present value are included in this report.

### Table 1

**Estimated Net Reserves And Income**  
Certain Illinois And Michigan Basin Proved Oil And Gas Interests  
Unescalated Prices And Costs  
BreitBurn Management Company, LLC  
As Of 31 December 2013

<table>
<thead>
<tr>
<th>Remaining Net Reserves</th>
<th>Proved Producing Reserves</th>
<th>Proved Non-producing Reserves</th>
<th>Proved Undeveloped Reserves</th>
<th>Total Proved Reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil – Mbbls</td>
<td>2,818.254</td>
<td>600.003</td>
<td>273.935</td>
<td>3,692.192</td>
</tr>
<tr>
<td>NGL – Mbbls</td>
<td>926.690</td>
<td>48.491</td>
<td>52.604</td>
<td>1,027.785</td>
</tr>
<tr>
<td>Gas – MMscf</td>
<td>316,539.156</td>
<td>12,953.759</td>
<td>3,431.957</td>
<td>332,924.875</td>
</tr>
<tr>
<td>Income Data (M$)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Future Net Revenue</td>
<td>1,523,989.000</td>
<td>107,700.977</td>
<td>40,053.676</td>
<td>1,671,743.750</td>
</tr>
<tr>
<td>Deductions</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating Expense</td>
<td>767,804.062</td>
<td>11,496.660</td>
<td>5,117.229</td>
<td>784,417.812</td>
</tr>
<tr>
<td>Production Taxes</td>
<td>102,827.188</td>
<td>7,248.276</td>
<td>2,695.613</td>
<td>112,771.086</td>
</tr>
<tr>
<td>Investment</td>
<td>37,347.488</td>
<td>4,034.191</td>
<td>6,438.310</td>
<td>47,819.988</td>
</tr>
<tr>
<td>Future Net Cashflow</td>
<td>616,010.438</td>
<td>84,921.852</td>
<td>25,802.525</td>
<td>726,734.875</td>
</tr>
<tr>
<td>Discounted PV @ 10% (M$)</td>
<td>284,025.688</td>
<td>36,373.836</td>
<td>13,250.457</td>
<td>333,649.938</td>
</tr>
</tbody>
</table>

Note: Proved non-producing and undeveloped reserves have a positive 10 percent discounted present value.
Values in the tables of this report may not add up arithmetically due to rounding procedure in the computer software program used to prepare the economic projections. All hydrocarbon liquids are reported as 42 gallon barrels. Gas volumes are reported at the standard pressure and temperature bases of the area where the gas is sold.

We are independent with respect to BreitBurn as provided in the SEC regulations. Neither the employment of nor the compensation received by PTS was contingent upon the values estimated for the properties included in this report.

Oil and gas reserves by definition fall into one of the following categories: proved, probable, and possible. The proved category is further divided into: developed and undeveloped. The developed reserve category is even further divided into the appropriate reserve status subcategories: producing and non-producing. Non-producing reserves include shut-in and behind-pipe reserves. The reserves included in this report include only proved reserves and do not include probable or possible reserves. BreitBurn has an active exploration and development program to develop their interests in certain tracts not classified as proved at this time. Future drilling may result in the reclassification of additional volumes to the proved reserve category. However, changes in the regulatory requirements for oil and gas operations may impact future development plans and the ability of the company to recover the estimated proved undeveloped reserves. The reserves and income attributable to the various reserve categories included in this report have not been adjusted to reflect the varying degrees of risk associated with them.

Reserve estimates are strictly technical judgments. The accuracy of any reserve estimate is a function of the quality and quantity of data available and of the engineering and geological interpretations. The reserve estimates presented in this report are believed reasonable; however, they are estimates only and should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify their revision. A portion of these reserves are for undeveloped locations and producing or non-producing wells that lack sufficient production history to utilize conventional performance-based reserve estimates. In these cases, the reserves are based on volumetric estimates and recovery efficiencies along with analogies to similar producing areas. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. As additional production and pressure data becomes available, these estimates may be revised up or down. Actual future prices may vary significantly from the prices used in this evaluation; therefore, future hydrocarbon volumes recovered and the income received from these volumes may vary significantly from those estimated in this report. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

Standard geological and engineering methods generally accepted by the petroleum industry were used in the estimation of BreitBurn’s reserves. Deterministic methods were used for all reserves included in this report. The appropriate combination of conventional decline curve analysis (DCA), production data analysis, volumetrics, reservoir simulation, and type curves were used to estimate the remaining reserves in the various producing areas. Volumetric calculations were based on data and maps provided by BreitBurn.

All prices used in preparation of this report were based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December 2013. The resulting reference gas price used was $3.671/MMBtu and the resulting reference oil price used was $96.94/Bbl. Henry Hub gas price and West Texas Intermediate oil price are common reference prices for natural gas and oil production in the U.S. The prices were adjusted for local differentials, gravity and Btu where applicable. As required by SEC guidelines, all pricing was held constant for the life of the projects (no escalation). Table 2 summarizes the 2013 reference prices and the resulting average prices used in this reserves evaluation. The average prices were calculated using the total future revenue by product prior to taxes and expenses divided by the total net reserves by product.
Table 2
BreitBurn Management Company, LLC
Oil, Gas And NGL Prices
Year End 2013 Reserves Evaluation

<table>
<thead>
<tr>
<th>Product</th>
<th>Reference Point</th>
<th>Year End 2013 Reference Price</th>
<th>Average Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>West Texas Intermediate</td>
<td>$96.94/Bbl</td>
<td>$91.48/Bbl</td>
</tr>
<tr>
<td>NGL</td>
<td>West Texas Intermediate</td>
<td>$96.94/Bbl</td>
<td>$27.05/Bbl</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>Henry Hub</td>
<td>$3.671MMBtu</td>
<td>$3.923/Mscf</td>
</tr>
</tbody>
</table>

Operating costs used in this report were based on values reported by BreitBurn and reviewed by PTS. BreitBurn’s estimates for capital costs for all non-producing and undeveloped wells are included in the evaluation. BreitBurn has indicated to us that they have the ability and intent to implement their capital expenditure program as scheduled. Operating costs and capital costs were held constant for the life of the projects (no escalation).

Net revenue (sales) is defined as the total proceeds from the sale of oil, condensate, natural gas liquids (NGL), and gas adjusted for commodity price basis differential and gathering/transportation expense. Future net income (cashflow) is future net revenue less net lease operating expenses, state severance or production taxes, operating/development capital expenses and net salvage. Future plugging, abandonment, and salvage costs are included at the economic life of each well or unit. No provisions for State or Federal income taxes have been made in this evaluation. The present worth (discounted cashflow) at various discount rates is calculated on a monthly basis.

In the conduct of our evaluation, we have not independently verified the accuracy and completeness of information and data furnished by BreitBurn with respect to ownership interests, historical oil and gas production, costs of operation and development, product prices, payout balances, and agreements relating to current and future operations and sales of production. If in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of the information or data provided by BreitBurn, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

In our opinion the above-described estimates of BreitBurn’s proved reserves and supporting data are, in the aggregate, reasonable. It is also our opinion that the above-described estimates of BreitBurn’s proved reserves conform to the definitions of proved oil and gas reserves promulgated by the Securities and Exchange Commission. These reserves definitions are provided at the conclusion of this letter.

All data used in this study were obtained from BreitBurn, public industry information sources, or the non-confidential files of PTS. A field inspection of the properties was not made in connection with the preparation of this report. The potential environmental liabilities attendant to ownership and/or operation of the properties have not been addressed in this report. Abandonment and clean-up costs and possible salvage value of the equipment were considered in this report.

In evaluating the information at our disposal related to this report, we have excluded from our consideration all matters which require a legal or accounting interpretation, or any interpretation other than those of an engineering or geological nature. In assessing the conclusions expressed in this report pertaining to all aspects of oil and gas evaluations, especially pertaining to reserve evaluations, there are uncertainties inherent in the interpretation of engineering data, and such conclusions represent only informed professional judgments.
Data and worksheets used in the preparation of this evaluation will be maintained in our files in Canonsburg and will be available for inspection by anyone having proper authorization from BreitBurn.

Sincerely yours,

/s/ Denise L. Delozier                        /s/ Charles M. Boyer II

Denise L. Delozier            Charles M. Boyer II, PG, CPG
Senior Engineer                            Northeast Basin Business Manager
                                          Advisor - Unconventional Reservoirs

/s/ Walter K. Sawyer

Walter K. Sawyer, PE              
Principal Consultant
(2) **Analogous reservoir.** Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

**Instruction to paragraph (a)(2):** Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(5) **Deterministic estimate.** The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) **Developed oil and gas reserves.** Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(10) **Economically producible.** The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(16) **Oil and gas producing activities.**

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

1. Lifting the oil and gas to the surface; and

2. Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

**Instruction 1 to paragraph (a)(16)(i):** The oil and gas production function shall be regarded as ending at a “terminal point”, which is the outlet valve on the lease or field storage tank. If unusual physical or
operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) **Probabilistic estimate.** The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(21) **Proved area.** The part of a property to which proved reserves have been specifically attributed.

(22) **Proved oil and gas reserves.** Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

   (A) The area identified by drilling and limited by fluid contacts, if any, and
   (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

   (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
   (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-
day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) **Proved properties.** Properties with proved reserves.

(24) **Reasonable certainty.** If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) **Reliable technology.** Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) **Reserves.** Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

**Note to paragraph (a)(26):** Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

(28) **Resources.** Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(31) **Undeveloped oil and gas reserves.** Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) **Unproved properties.** Properties with no proved reserves.
January 16, 2014

Mr. Mark L. Pease
BreitBurn Management Company, LLC
600 Travis Street, Suite 4800
Houston, Texas 77002
Re: Reserve Evaluation

Dear Mr. Pease:

As requested, this report was prepared on January 16, 2014 for BreitBurn Management Company, LLC (“BreitBurn”) for the purpose of submitting our estimates of total proved reserves and forecasts of economics attributable to the subject interests. The reserves and future net revenue are to the interest of BreitBurn Operating L.P. (“BOLP”). We evaluated 100% of BreitBurn Postle area reserves, which are made up of oil properties in the Postle field in Texas County, Oklahoma and represent 20% of BreitBurn’s total proved reserves. This report utilized an effective date of December 31, 2013, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the Securities and Exchange Commission (SEC). The results of this evaluation are presented in the accompanying tabulation, with a composite summary of the values presented below:

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<table>
<thead>
<tr>
<th>Net Reserves</th>
<th>Developed</th>
<th>Proved</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Producing</td>
<td>Undeveloped</td>
<td>Proved</td>
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<tr>
<td>Oil</td>
<td>– Mbbl</td>
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<tr>
<td>Gas</td>
<td>– MMcf</td>
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<tr>
<td>NGL</td>
<td>– Mbbl</td>
<td>3,771.1</td>
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<td>Revenue</td>
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<td></td>
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<tr>
<td>Oil</td>
<td>– M$</td>
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<tr>
<td>Gas</td>
<td>– M$</td>
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<td>Ad Valorem Taxes</td>
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<td>Operating Expenses</td>
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<td>Other Deductions</td>
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<td>Investments</td>
<td>– M$</td>
<td>71,783.7</td>
<td>173,982.5</td>
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<td>Net Operating Income (BFIT)</td>
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<td>726,706.9</td>
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<td>Discounted at 10%</td>
<td>– M$</td>
<td>723,984.1</td>
<td>304,177.6</td>
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</table>

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**BreitBurn Management Company, LLC Interests**
Total Proved Reserves
Postle Area
As of December 31, 2013

Pursuant to the Guidelines of the
Securities and Exchange Commission for
Reporting Corporate Reserves and
Future Net Revenue
Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its “present worth”. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

**Hydrocarbon Pricing**

The base SEC oil and gas prices calculated for December 31, 2013 were $96.94/bbl and $3.671/MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The base oil and gas prices are based upon WTI-Cushing and Henry Hub spot prices, respectively, as published by the EIA for January 1, 2013 through December 1, 2013.

The base prices shown above were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $92.32 per barrel for oil and $4.222 per MCF for gas. All economic factors were held constant in accordance with SEC guidelines.

**Economic Parameters**

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, severance taxes and lease operating expenses were calculated and prepared by BreitBurn and were reviewed by us for reasonableness. Capital costs for new development wells, production equipment and workovers were scheduled as provided by BreitBurn. Capital costs were reviewed by us for reasonableness and compared to capital costs provided in previous years. Adjustments were made as necessary after a review with BreitBurn. Lease operating expenses were either determined at the field or individual well level using averages calculated from historical lease operating statements. All economic parameters, including lease operating expenses and capital costs, were held constant (not escalated) throughout the life of these properties.

**SEC Conformance and Regulations**

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in pages 3 and 4 of the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. Government policies and market conditions different from those employed in this report may cause (1) the total quantity of oil or gas to be recovered, (2) actual production rates, (3) prices received, or (4) operating and capital costs to vary from those presented in this report. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.
This evaluation includes 7 proved undeveloped locations in the Postle field in the Texas County, Oklahoma. As requested, estimates of proved developed non-producing and proved undeveloped reserves have only been included for properties that are economically producible at existing economic conditions. Each of these drilling locations proposed as part of BreitBurn’s development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, BreitBurn has indicated they have every intent to complete this development plan within the next five years. Furthermore, BreitBurn has demonstrated that they have the proper company staffing, financial backing and prior development success to ensure this five year development plan will be fully executed.

**Reserve Estimation Methods**

The methods employed in estimating reserves are described in page 2 of the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for BreitBurn properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

**General Discussion**

An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. (“CG&A”) Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have not been included.

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. This report has been prepared for BOLP’s use in filing with the Securities and Exchange Commission. This evaluation was supervised by Robert D. Ravnaas, President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer.
(License #61304). We do not own an interest in the properties, BreitBurn Management Company, LLC and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

The professional qualifications of the undersigned, the technical person primarily responsible for the preparation of this report, are included as an attachment to this letter.

Sincerely,

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

[Signature]

Robert D. Ravnaas, P.E.
President