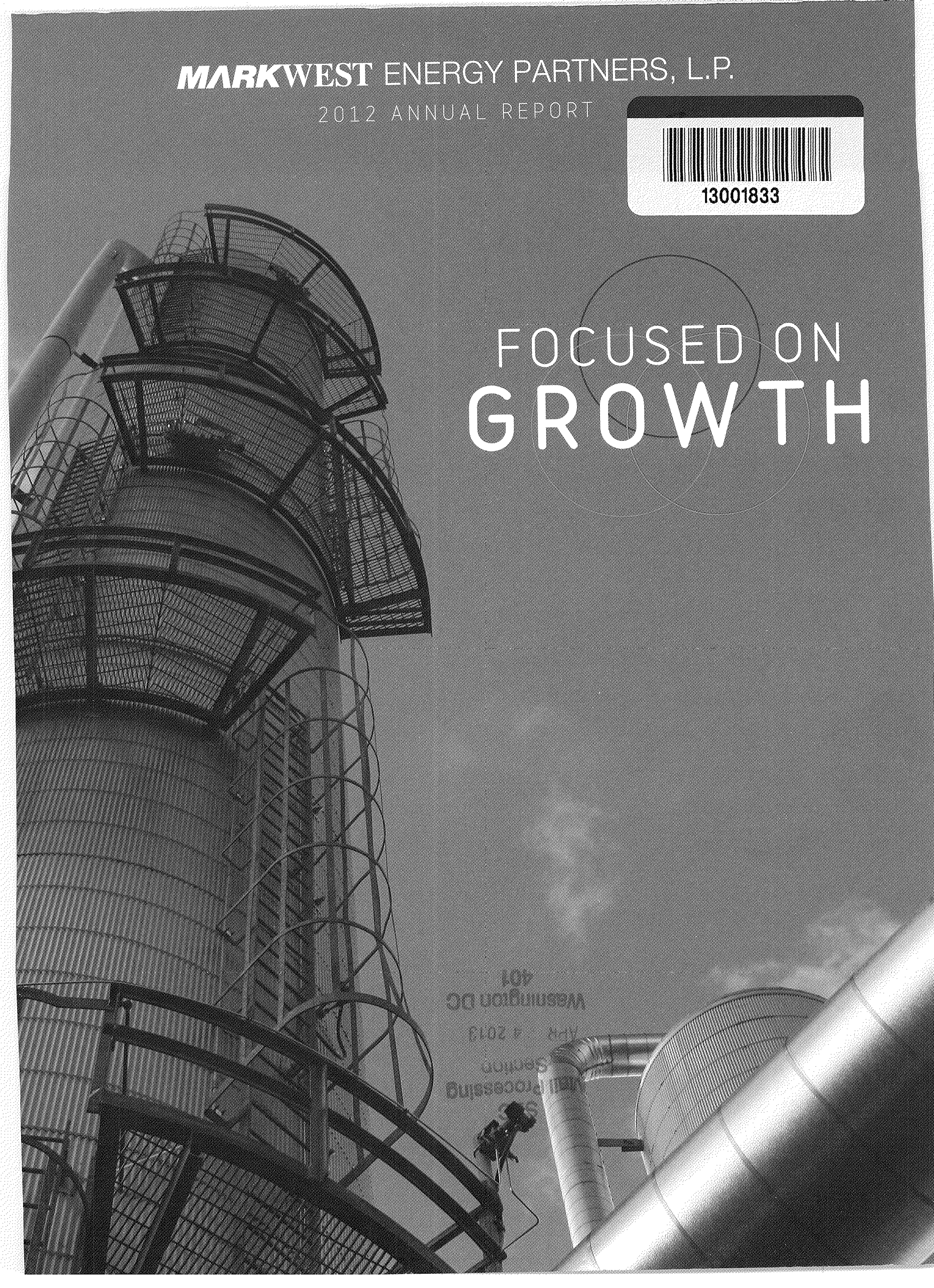
# MARKWEST ENERGY PARTNERS, L.P.

2012 ANNUAL REPORT



# FOCUSED ON GROWTH



# UTICA

In the Utica Segment, we have partnered with The Energy and Minerals Group (EMG) to develop fully integrated gathering, processing, fractionation, storage, and marketing operations in the liquids-rich Utica Shale in Ohio.

**AREAS OF OPERATION:** Ohio

**RESOURCE PLAY:** Utica Shale

**GATHERING:** 60 MMcf/d gathering capacity

**PROCESSING:** 60 MMcf/d processing capacity

**UNDER CONSTRUCTION**

**PROCESSING:** 725 MMcf/d processing capacity at Cadiz and Seneca complexes

**FRACTIONATION:** 60,000 Bbl/d C3+ fractionation capacity[1]

40,000 Bbl/d de-ethanization capacity

**OTHER:** NGL marketing by truck, railcar, and pipeline

[1] *60% of C3+ fractionation capacity is owned by a wholly owned subsidiary of MarkWest Energy Partners, L.P.*

*We are developing a leading position in the southern core of the highly prospective Utica Shale.*

# SOUTHWEST

In the Southwest Segment, we gather, process, and transport natural gas and natural gas liquids in East Texas, Southeast Oklahoma, Western Oklahoma, and several smaller systems throughout the Southwest. In addition, we process and fractionate off-gas on behalf of six oil refineries in the Gulf Coast.

**AREAS OF OPERATION:** Oklahoma, Texas, and New Mexico

**RESOURCE PLAYS:** Granite Wash, Haynesville Shale, Woodford Shale, Permian Basin, Anadarko Basin, and the Cotton Valley, Travis, and Pettit Formations

**GATHERING:** Over 1.6 Bcf/d gathering capacity

**PROCESSING:** 817 MMcf/d processing capacity

**FRACTIONATION:** 29,000 Bbl/d NGL fractionation capacity

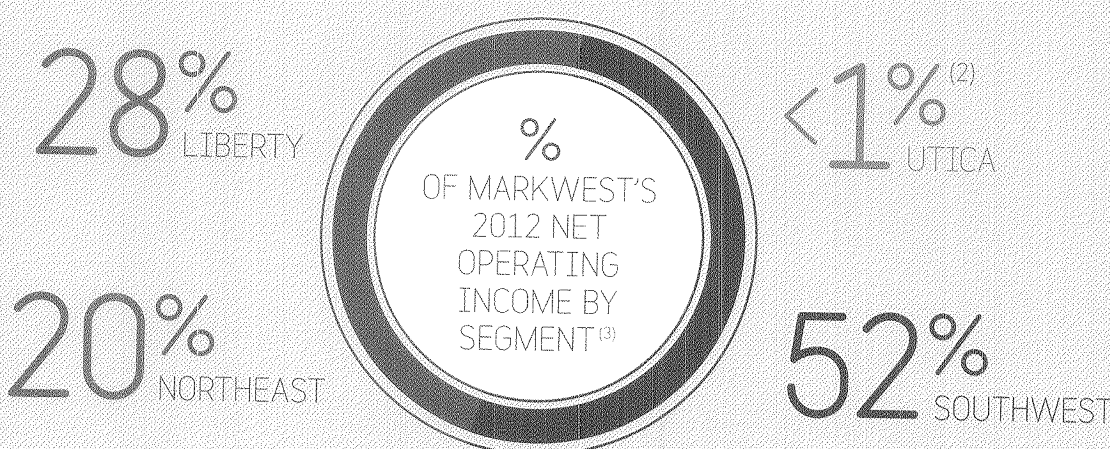
**TRANSPORTATION:** 638,000 Dth/d of intrastate transportation capacity on Arkoma Connector Pipeline

**OTHER:** NGL marketing and transportation

**UNDER CONSTRUCTION**

**PROCESSING:** 120 MMcf/d processing capacity at Centrahoma, our joint venture in the Woodford Shale

*We maintain best-in-class midstream services in the Granite Wash, Haynesville and Woodford Shales.*




[2] *For 2012, the Utica Segment was under development and is expected to begin to contribute to net operating income in 2013.*

[3] *Net Operating Income by Segment Before Items not Allocated to Segments is a non-GAAP financial measure. Please read Note 23 in Item 8 of the enclosed Annual Report on Form 10-K for further discussion and reconciliation of this financial measure.*

## LIBERTY

The Liberty Segment provides natural gas *midstream services in the liquids-rich areas* of the Marcellus Shale, with fully integrated gathering, processing, fractionation, storage, and marketing operations.

**AREAS OF OPERATION:** Southwest and Northwest Pennsylvania and Northern West Virginia

**RESOURCE PLAY:** Marcellus Shale

**GATHERING:** 855 MMcf/d gathering capacity

**PROCESSING:** Over 1.1 Bcf/d processing capacity

**FRACTIONATION:** 60,000 Bbl/d C3+ fractionation capacity

**STORAGE:** 90,000 barrel NGL storage capacity with access to over 900M barrels of propane storage

**OTHER:** NGL marketing by truck, railcar, pipeline, and LPG ship

**UNDER CONSTRUCTION**

**PROCESSING:** Over 1.8 Bcf/d processing capacity at Majorsville, Mobley, Sherwood, and Keystone complexes

**FRACTIONATION:** 115,000 Bbl/d de-ethanization capacity

*We are the largest processor and fractionator in the expansive Marcellus Shale.*

## NORTHEAST

Our Appalachian assets include five natural gas processing complexes, and one fractionation and storage facility. In addition to natural gas processing, fractionation, storage, and marketing in Appalachia, we also operate a crude oil transportation pipeline in Michigan.

**AREAS OF OPERATION:** Kentucky, Southern West Virginia, and Michigan

**RESOURCE PLAYS:** Appalachian Basin, Huron/Berea Shale, and the Niagaran Reef

**PROCESSING:** 652 MMcf/d processing capacity

**FRACTIONATION:** 24,000 Bbl/d C3+ fractionation capacity

**STORAGE:** 285,000 barrel NGL storage capacity with access to over 900M barrels of propane storage

**OTHER:** NGL marketing by truck, railcar, pipeline, and river barge

*We are the largest processor and fractionator in the Appalachian Basin.*

We develop high-quality, strategically located, diversified assets in the liquids-rich areas of the natural gas resource plays in the United States.

SOLUTIONS

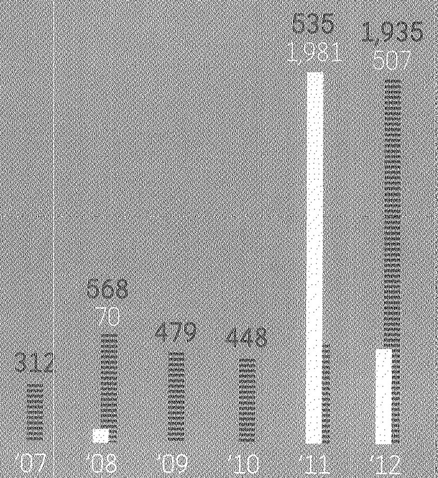
# FINANCIAL HIGHLIGHTS

## GROWTH CAPITAL INVESTMENT

*($ in millions)*

Acquisitions

Growth Capital Expenditures



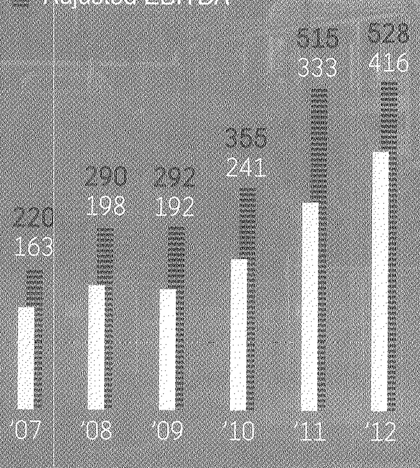

*NOTE: Numbers include growth capital that has been funded through joint ventures and divestiture activities. For additional information, see Item 6 – Selected Financial Data of this Annual Report on Form 10-K.*

## FINANCIAL PERFORMANCE

*($ in millions)*

Distributable Cash Flow

Adjusted EBITDA




*NOTE: See note on cover page to Annual Report on Form 10-K for important disclosures regarding these non-GAAP financial measures.*

# $1.9B

IN 2012, WE INVESTED $1.9B IN ORGANIC GROWTH PROJECTS, PRIMARILY IN THE MARCELLUS SHALE

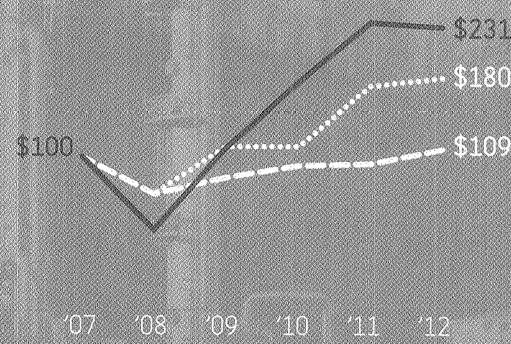
## TOTAL RETURN TO UNITHOLDERS

*(assumes $100 investment on 12.31.07)*

MarkWest Energy Partners, L.P. (MWE)

S&P 500 Total Return Index

Alerian MLP Total Return Index




*Source: Bloomberg*

# 131%

TOTAL RETURN TO UNITHOLDERS SINCE 2007

GROWTH

# LETTER TO UNITHOLDERS

2012 WAS ANOTHER EXCEPTIONAL YEAR OF GROWTH AND PERFORMANCE FOR MARKWEST, AS WE CONTINUED TO EXPAND OUR POSITION IN SEVERAL OF THE PREMIER LIQUIDS-RICH RESOURCE GAS PLAYS IN THE UNITED STATES. OUR FOCUS ON EXECUTION AND OUR COMMITMENT TO EXCEPTIONAL CUSTOMER SERVICE DROVE ANOTHER YEAR OF RECORD OPERATIONAL AND FINANCIAL RESULTS.

We achieved record distributable cash flow of $416 million and adjusted EBITDA of $528 million in 2012. Distributions per unit applicable to the full year increased almost 13 percent, and we maintained a distribution coverage ratio of 1.12. Our simplified corporate structure with no incentive distribution rights results in a lower cost of capital and remains a key advantage relative to other publicly traded partnerships. We successfully raised $2.4 billion in capital in 2012 from the public equity and debt markets and increased the total borrowing capacity of our revolving credit facility by one-third to $1.2 billion. In addition, we recently expanded our existing joint venture agreement with The Energy & Minerals Group (EMG), whereby they will contribute up to an additional $450 million in capital toward the continued development of our midstream operations in Ohio. As a result, we are well positioned to fund our 2013 capital investment program which is focused on organic growth projects throughout our key operating areas in Oklahoma, Texas, West Virginia, Pennsylvania and Ohio.

Throughout our operating segments, we have continued to grow our total volumes through a diverse set of high-quality and well-positioned assets. In 2012 we increased our processing capacity by over 800 million cubic feet per day (MMcf/d), and this year we expect to complete over 1.6 billion cubic feet (Bcf/d) of additional capacity. Even more exciting is the point that our growth has reached in our Liberty Segment, which serves producer customers operating in the expansive Marcellus Shale. Liberty-gathered volumes increased more than 70 percent, processed volumes increased over 50 percent, and fractionated NGLs (natural gas liquids) more than doubled from 2011 to 2012.

The Marcellus Shale is now the largest producing gas field in the United States, and MarkWest is excited to have a leading position throughout the liquids-rich area of the play. We have continued to lead the development of critical midstream infrastructure by investing almost $2 billion in 2012, primarily on organic growth projects in Pennsylvania and West Virginia. With five large-scale processing complexes now in operation, we are supporting our producer customers as they unlock the enormous potential of one of the finest producing natural gas fields in the world. Equally as impressive is the impact our Liberty operations continue to have on local economies. Since 2008 we have created more than 250 full-time positions in the Marcellus Shale, and this year we plan to increase this amount by approximately 50 percent.

In May of 2012, we expanded our Liberty operations with the acquisition of Keystone Midstream in Butler County, Pennsylvania. The acquisition strategically positions us in the growing rich-gas area of the Marcellus Shale in northwest Pennsylvania, and we are poised to benefit from the ability to develop these assets in conjunction with our integrated midstream operations located about 50 miles south.

In order to support the ongoing success of our producer customers in the Marcellus Shale, we have installed 1.1 Bcf/d of processing capacity and plan to double this amount to 2.2 Bcf/d in 2013 with the completion of six new processing plants. In conjunction with the addition of our significant processing expansions, we are developing additional fractionation capacity to support producers' requirements for ethane extraction. With the installation of three large-scale de-ethanization facilities at our Houston and Majorsville complexes, we expect to have the ability to produce approximately 115,000 barrels per day (Bbl/d) of purity ethane from the Marcellus Shale by early 2014. Producers will have

**$416M**

RECORD DISTRIBUTABLE CASH FLOW IN 2012

EXECUTION

access to all of the planned ethane pipeline projects including Mariner West, Mariner East, and ATEX Express. Given our long history of marketing NGLs in the Northeast, we continue to lead the development of solutions that can provide our producers maximum value from their NGL production. We believe that the ability to fractionate and market purity products in the Northeast will result in a sustained pricing advantage for many years to come.

It's amazing to think that by the end of 2013, in just over five years, we will have placed in operation 15 processing plants and three fractionation facilities in the Marcellus Shale; and while the pace of this growth is simply astounding, what's beginning to take place in neighboring eastern Ohio is equally significant. Initial well results from the Utica Shale have surpassed expectations; and together with our joint venture partner EMG, we are rapidly developing a fully integrated midstream system throughout the southern core area of the play.

"IN 2012 WE INCREASED OUR PROCESSING CAPACITY BY OVER 800 MMCF/D, AND THIS YEAR WE EXPECT TO COMPLETE OVER 1.6 BCF/D OF ADDITIONAL CAPACITY."

In 2012, we began operations of our extensive gathering system and the first of our two major processing complexes in the Utica. Our current construction plans have us on track to deliver over 700 MMcf/d per day of processing capacity that is backed by long-term fee-based contracts from multiple producers. In addition, we are installing fractionation capacity to handle 100,000 barrels per day of liquids production from the Utica and Marcellus Shales and an extensive logistics hub that will be able to deliver purity products to market by truck, rail, and pipeline.

As you can tell, our expanding footprint in the Utica Shale has the potential to become a significant part of MarkWest's operations and provide us with many years of organic growth opportunities. We are excited to lead the development of the hundreds of miles of gathering pipeline, processing, and fractionation services on behalf of our Ohio producers, and we look forward to customizing unique solutions to meet their dynamic drilling plans.

Building infrastructure throughout the Northeast is something we've been doing for nearly 25 years, and we remain the largest processor and fractionator of natural gas in the Appalachian basin. Our strategically positioned assets in southern West Virginia and Kentucky include over 650 MMcf/d of processing capacity and 24,000 Bbl/d of fractionation. During the second half of 2012 we commenced operations of a new cryogenic processing facility at our Langley complex and continue to provide high-quality producer services in the basin.

While MarkWest is certainly focused on growing in the Northeast, our best-in-class midstream assets in the Southwest continue to produce steady results. Our operations in Texas and Oklahoma include 1.6 Bcf/d of gathering capacity and over 800 MMcf/d of processing capacity throughout proven resource areas with high-quality reserves. In 2012, we completed a major expansion in East Texas, adding an additional 120 MMcf/d per day of processing capacity on behalf of our producer customers successfully drilling liquids-rich areas of the Haynesville Shale and Cotton Valley formation. As a result, processed volumes in East Texas have increased almost 20 percent when compared to 2011. In Southeast Oklahoma, we maintain a significant gas-gathering system in the Woodford Shale; and in Western Oklahoma, we continue to support development in the highly economical Granite Wash formation. We're also fortunate to have a unique asset in Javelina, a processing and fractionation facility in the Gulf Coast, which plays an important role in treatment of off-gas from local area refineries.

23%

INCREASE IN TOTAL PROCESSED VOLUMES IN 2012

In summary, 2012 was an exceptional year for MarkWest, but we're not slowing down in 2013. The growth of domestic energy production hinges on the development of critical midstream infrastructure throughout emerging resource plays. We believe that our strong relationships with successful producer customers, a geographically diverse asset base, and employees recognized for their outstanding customer service will create future opportunities that cannot be easily replicated. These tremendous opportunities continue to support our goal of providing superior and sustainable total returns for our unitholders.

Thank you for your continued support.

**Frank M. Semple**
*Chairman, President and Chief Executive Officer*

April 15, 2013

# MARKWEST ENERGY PARTNERS, L.P.

## 2012
## ANNUAL REPORT
## ON FORM 10-K

**Disclaimer:** *The statements included in this Annual Report contain "forward-looking statements" within the meaning of the Securities Act of 1933 and the Securities Exchange Act of 1934, each as amended. These forward-looking statements (which in many instances can be identified by words like "may," "will," "should," "expects," "plans," "believes," and other comparable words) are based on the Partnership's current expectations and beliefs concerning future developments and their potential effects on the Partnership, but are not guarantees of future performance, and involve risks and uncertainties. You are cautioned not to place undue reliance on forward-looking statements, as many of these factors are beyond our ability to control or predict, and which speak only as of the date hereof. The Partnership undertakes 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. You are urged to carefully review and consider the cautionary statements and other disclosures made in the Partnership's enclosed Annual Report on Form 10-K for fiscal year 2012, including under the heading "Risk Factors," which identify and discuss significant risks, uncertainties, and various other factors that could cause actual results to vary significantly from those expected or implied in the forward-looking statements.*

---

*Distributable Cash Flow (DCF) and Adjusted EBITDA are non-GAAP financial measures. The GAAP measure most directly comparable to DCF and Adjusted EBITDA is net income (loss). In general, we define DCF as net income (loss) adjusted for (i) depreciation, amortization, impairment, and other non-cash expense; (ii) amortization of deferred financing costs and discount; (iii) loss on redemption of debt net of current tax benefit; (iv) non-cash (earnings) loss from unconsolidated affiliates; (v) distributions from (contributions to) unconsolidated affiliates (net of affiliate growth capital expenditures); (vi) non-cash compensation expense; (vii) non-cash derivative activity; (viii) losses (gains) on the disposal of property, plant, and equipment (PP&E) and unconsolidated affiliates; (ix) provision for deferred income taxes; (x) cash adjustments for non-controlling interest in consolidated subsidiaries; (xi) revenue deferral adjustment; (xii) losses (gains) relating to other miscellaneous non-cash amounts affecting net income for the period; and (xiii) maintenance capital expenditures, net of joint venture partner contributions. We define Adjusted EBITDA as net income (loss) adjusted for (i) depreciation, amortization, impairment, and other non-cash expense; (ii) interest expense; (iii) amortization of deferred financing costs; (iv) loss on redemption of debt; (v) losses (gains) on the disposal of PP&E and unconsolidated affiliates; (vi) non-cash derivative activity; (vii) non-cash compensation expense; (viii) provision for income taxes; (ix) adjustments for cash flow from unconsolidated affiliates; (x) adjustment related to non-guarantor, consolidated subsidiaries; and (xi) losses (gains) relating to other miscellaneous non-cash amounts affecting net income for the period. Please see the Form 8-K we filed concurrently with our 2012 Proxy Statement for our calculations of DCF and Adjusted EBITDA, along with the corresponding reconciliations to net income and management's reasons for including such financial measures in this Annual Report.*

# 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, 2012**

**or**

☐ **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 001-31239**

# MARKWEST ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **27-0005456** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**1515 Arapahoe Street, Tower 1, Suite 1600, Denver, CO 80202-2137**
(Address of principal executive offices)

Registrant's telephone number, including area code: **303-925-9200**

Securities registered pursuant to Section 12(b) of the Act: **Common units representing limited partner interests, New York Stock Exchange**

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III 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 ☐<br>(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 common units held by non-affiliates of the registrant on June 30, 2012 was approximately $5.5 billion. As of February 19, 2013, the number of the registrant's common units and Class B units outstanding were 129,134,880 and 19,954,389, respectively.

**DOCUMENTS INCORPORATED BY REFERENCE:**

The information required by Part III of this Report, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement relating to the Annual Meeting of Unitholders to be held in 2013, which definitive proxy statement shall be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Report relates.

**MarkWest Energy Partners, L.P.**
**Form 10-K**

**Table of Contents**



Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Forward-Looking Statements" included later in this section for an explanation of these types of assertions. Also, in this document, unless the context requires otherwise, references to "we," "us," "our," "MarkWest Energy" or the "Partnership" are intended to mean MarkWest Energy Partners, L.P., and its consolidated subsidiaries. References to "MarkWest Hydrocarbon" or the "Corporation" are intended to mean MarkWest Hydrocarbon, Inc., a wholly-owned taxable subsidiary of the Partnership. References to "General Partner" are intended to mean MarkWest Energy GP, L.L.C., the general partner of the Partnership.

## Glossary of Terms

The abbreviations, acronyms and industry technology used in this report are defined as follows.

| | |
|---|---|
| Bbl | Barrel |
| Bbl/d | Barrels per day |
| Bcf/d | Billion cubic feet per day |
| Btu | One British thermal unit, an energy measurement |
| Credit Facility | Amended and restated revolving credit agreement |
| DER | Distribution equivalent right |
| Dth/d | Dekatherms per day |
| EBITDA (a non-GAAP financial measure) | Earnings Before Interest, Taxes, Depreciation and Amortization |
| EPA | Environmental Protection Agency |
| ERCOT | Electric Reliability Council of Texas |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | Accounting principles generally accepted in the United States of America |
| Gal | Gallon |
| Gal/d | Gallons per day |
| IFRS | International Financial Reporting Standards |
| LIBOR | London Interbank Offered Rate |
| Mcf | One thousand cubic feet of natural gas |
| Mcf/d | One thousand cubic feet of natural gas per day |
| MMBtu | One million British thermal units, an energy measurement |
| MMBtu/d | One million British thermal units per day |
| MMcf/d | One million cubic feet of natural gas per day |
| Net operating margin (a non-GAAP financial measure) | Segment revenue, excluding any derivative gain (loss), less purchased product costs, excluding any derivative gain (loss) |
| NGL | Natural gas liquids, such as ethane, propane, butanes and natural gasoline |
| N/A | Not applicable |
| OTC | Over-the-Counter |
| SEC | Securities and Exchange Commission |
| SMR | Steam methane reformer, operated by a third party and located at the Javelina gas processing and fractionation facility in Corpus Christi, Texas |
| TSR Performance Units | Phantom units containing performance vesting criteria related to the Partnership's total shareholder return |
| VIE | Variable interest entity |
| WTI | West Texas Intermediate |

## Forward-Looking Statements

Certain statements and information included in this Annual Report on Form 10-K may constitute "forward-looking statements." The words "could," "may," "predict," "should," "expect," "hope," "continue," "potential," "plan," "intend," "anticipate," "project," "believe," "estimate" and similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on current expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. 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 revenues 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 those described in (i) Item 1A. Risk Factors of this Form 10-K and elsewhere in this report, (ii) our reports and registration statements filed from time to time with the SEC and (iii) other announcements we make from time to time. Investors 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. Undue reliance should not be placed on forward-looking statements as many of these factors are beyond our ability to control or predict.

## PART I

### ITEM 1. Business

#### General

MarkWest Energy Partners, L.P. is a publicly traded Delaware limited partnership formed in January 2002. We are a master limited partnership engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the gathering and transportation of crude oil. We have a leading presence in many unconventional gas plays including the Marcellus Shale, Utica Shale, Huron/Berea Shale, Haynesville Shale, Woodford Shale and Granite Wash formation. We conduct our operations in the following operating segments: Southwest, Northeast, Liberty and Utica. The Southwest segment includes the operations of our processing facilities in Corpus Christi, TX that were reported separately in the Gulf Coast segment in prior years. The Utica segment includes our operations in the Utica Shale region in eastern Ohio and has previously been included in the Liberty segment. Maps detailing the individual assets can be found on our Internet website, *www.markwest.com*. For more information on these segments, see *Our Operating Segments* discussion below.

The following table summarizes the operating performance for each segment for the year ended December 31, 2012 (amounts in thousands). For further discussion of our segments and a reconciliation to our consolidated statement of operations, see Note 23 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

| | Southwest | Northeast | Liberty | Utica | Total |
|---|---|---|---|---|---|
| Revenue | $856,416 | $225,818 | $319,867 | $ 571 | $1,402,672 |
| Purchased product costs | 387,902 | 68,402 | 74,024 | — | 530,328 |
| Net operating margin(1) | 468,514 | 157,416 | 245,843 | 571 | 872,344 |
| Facility expenses | 124,921 | 24,106 | 65,825 | 3,968 | 218,820 |
| Portion of operating income attributable to non-controlling interests | 5,790 | — | — | (1,359) | 4,431 |
| Operating income before items not allocated to segments | $337,803 | $133,310 | $180,018 | $(2,038) | $ 649,093 |

(1) Net operating margin is a non-GAAP financial measure. For a reconciliation of net operating margin to income from operations, the most comparable GAAP financial measure, see *Non-GAAP Measures* discussion below.

#### Organizational Structure

We are a master limited partnership with outstanding common units, Class A units and Class B units.

- Our common units are publicly traded on the New York Stock Exchange under the symbol "MWE."
- All of our Class A units are owned by MarkWest Hydrocarbon and our General Partner, which are our wholly-owned subsidiaries, as a result of the ownership structure adopted after the February 2008 merger of the Partnership and MarkWest Hydrocarbon (the "Merger"). The Class A units generally share in our income or losses on a pro-rata basis with our common units and our Class B units, however the Class A units do not share in any income or losses that are attributable to our ownership interest (or disposition of such interest) in MarkWest Hydrocarbon. The only impact of the Class A units on our consolidated results of operations

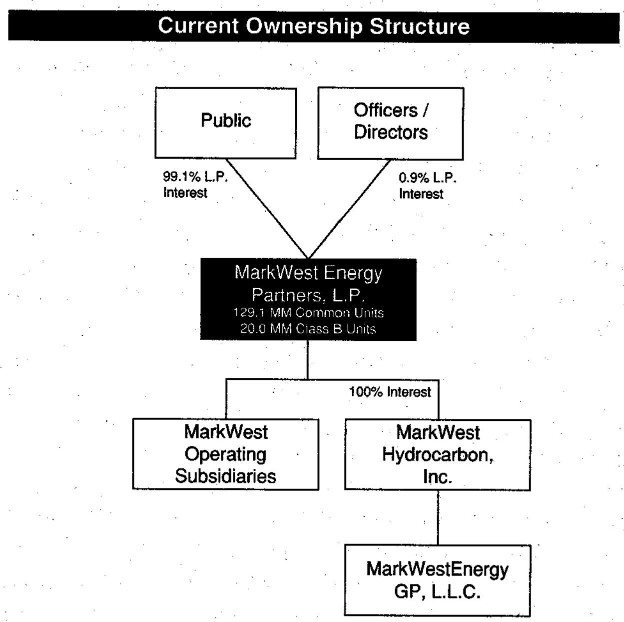
and financial position is that MarkWest Hydrocarbon pays income tax on its pro-rata share of our income or losses. The Class A units do not have voting rights, except as required by law.

- All of our Class B units were issued to and are held by M&R MWE Liberty, LLC ("M&R"), an affiliate of The Energy and Minerals Group ("EMG"), as part of our December 31, 2011 acquisition of the non-controlling interest in MarkWest Liberty Midstream & Resources, L.L.C. ("MarkWest Liberty Midstream"). The Class B units will convert to common units on a one-for-one basis (the "Converted Units") in five equal installments beginning on July 1, 2013 and each of the first four anniversaries of such date. Class B units (i) share in our income and losses, (ii) are not entitled to participate in any distributions of available cash prior to their conversion and (iii) do not have the right to vote on, approve or disapprove, or otherwise consent to or not consent to any matter (including mergers, unit exchanges and similar statutory authorizations) other than those matters that disproportionately and adversely affect the rights and preferences of the Class B units. Upon conversion of the Class B units, the right of M&R and certain of its affiliates to vote as a common unitholder of the Partnership will be limited to a maximum of 5% of the Partnership's outstanding common units. Once converted, M&R and certain of its affiliates will have the right to participate in the Partnership's underwritten offerings of our common units in an amount up to 20% of the total number of common units offered and will have comparable 20% participation and sale rights with respect to any continuous equity or similar program that is implemented or effective during any period after the conversion of Class B units. In addition, M&R and certain of its affiliates will have the right to demand that we conduct up to three underwritten offerings beginning in 2017, but restricted to no more than one offering in any twelve-month period. M&R also has limited rights to distribute an aggregate of 2,500,000 common units to its members and their limited partners beginning in 2016. Except as described above, M&R is not permitted to transfer its Class B units or Converted Units without the prior written consent of the General Partner's board of directors (the "Board").

The following table provides the aggregate number of units and relative ownership interests of the Class A and B units and common units as of February 19, 2013 (units in millions):

| | Units | % |
|---|---|---|
| Common units | 129.1 | 75.2% |
| Class A units | 22.6 | 13.2% |
| Class B units | 20.0 | 11.6% |
| Total units | 171.7 | 100% |

The Class A units are not treated as outstanding common units in the accompanying Consolidated Balance Sheets as they are all held by our wholly owned subsidiaries and therefore eliminated in consolidation. The ownership percentages as of February 19, 2013 in the graphic depicted below reflect the Partnership structure from the basis of the consolidated financial statements with the Class A units eliminated in consolidation. All Class B units are owned by M&R and included in the public ownership percentage.




The primary benefit of our organizational structure is the absence of incentive distribution rights, which represents a general partner's right to receive an increasing percentage of quarterly distributions of available cash after a minimum quarterly distribution and certain target distribution levels had been achieved. The absence of incentive distribution rights substantially lowers our cost of equity capital and increases the cash available to be distributed to our common unitholders. This enhances our ability to compete for organic growth projects and new acquisitions and improves the returns to our unitholders on all future expansion projects.

**Key Developments**

***Expansion of Marcellus Shale Operations***

In May 2012, we acquired natural gas gathering and processing assets from Keystone Midstream Services, LLC ("Keystone") for a final purchase price of approximately $507.3 million. The acquisition expanded our presence in the liquids-rich Marcellus Shale into northwest Pennsylvania. Keystone's existing assets are located in Butler County, Pennsylvania and include two cryogenic gas processing plants totaling approximately 90 MMcf/d of processing capacity, a gas gathering system and associated field compression ("Keystone Complex"). This acquisition is referred to as the "Keystone Acquisition."

As a result of the Keystone Acquisition, we became a party to a long-term fee-based agreement to gather and process certain natural gas owned or controlled by R.E. Gas Development, L.L.C. ("Rex Energy"), a subsidiary of Rex Energy Corporation, and Summit Discovery Resources II, L.L.C. ("Summit"), a subsidiary of Sumitomo Corporation, at the acquired facilities and in 2013 to exchange the resulting NGLs for fractionated products at facilities already owned and operated by us. Rex Energy and Summit have dedicated an area of approximately 900 square miles to us as part of this long-term gathering and processing agreement.

During the third quarter of 2012, we began operations of 200 MMcf/d of processing capacity at our facilities in Sherwood, West Virginia ("Sherwood Complex"). An additional 400 MMcf/d of processing capacity is expected to commence operation at our Sherwood Complex during 2013. The processing expansion under construction at the Sherwood Complex is supported by a long-term fee-based agreement with Antero Resources Appalachian Corporation ("Antero").

During the fourth quarter of 2012, we began operations of 200 MMcf/d of processing capacity in Mobley, West Virginia ("Mobley Complex"). An additional 320 MMcf/d of processing capacity is expected to commence operation at our Mobley Complex during 2013. The expansion facilities are supported by long-term fee-based agreements with EQT and Magnum Hunter Resources Corporation.

In 2012, we announced an 800 MMcf/d expansion of our processing facilities in Majorsville, West Virginia (the "Majorsville Complex") that is supported by long-term processing agreements with CONSOL Energy Inc., Noble Energy Inc., Range Resources Corporation, Statoil ASA, and an affiliate of Chesapeake Energy Corporation. This expansion consists of four, 200 MMcf/d processing plants that are expected to begin operations in 2013 and 2014 and will bring the total cryogenic processing capacity at the Majorsville Complex to approximately 1.1 Bcf/d.

In July 2012, we announced a long-term fee-based agreement with XTO Energy Inc., a subsidiary of Exxon Mobil Corporation ("XTO") to extend our NGL gathering pipeline in northwest Pennsylvania to XTO's processing plant in Butler County, Pennsylvania. The NGLs will be transported by truck until the pipeline is completed in early 2014.

In September 2012, we signed a 10-year agreement to become a firm shipper on the Mariner East ("Mariner East") pipeline subject to final regulatory approvals. Mariner East is currently designed to transport ethane and propane sourced at our Houston, Pennsylvania processing and fractionation complex ("Houston Complex") to Sunoco Inc. and its affiliates' ("Sunoco") Marcus Hook facility near Philadelphia, Pennsylvania. Once delivered, the ethane-propane mix will be re-fractionated into purity products for sale into domestic and international markets.

***Utica Shale Operations***

In June 2012, MarkWest Utica EMG, L.L.C. and its subsidiaries ("MarkWest Utica EMG") executed long-term fee-based agreements with Gulfport Energy Corporation ("Gulfport") to provide gathering, processing, fractionation, and marketing services in the liquids-rich corridor of the Utica Shale. Under the terms of the agreements, MarkWest Utica EMG is developing natural gas gathering infrastructure, which provides service to Gulfport, primarily in Harrison, Guernsey, and Belmont counties. Initial operations began in the third quarter of 2012. MarkWest Utica EMG is processing the gas at its processing facilities in Cadiz Township in Ohio ("Cadiz Complex"), and is expected to provide NGL fractionation and marketing services at its fractionation facility in Harrison County, Ohio ("Harrison Fractionation Facility") when it is completed in the first quarter of 2014.

In November 2012, MarkWest Utica EMG executed long-term fee-based agreements with two producers, Antero and Rex Energy, to provide gas processing, fractionation, and marketing services in Noble County, Ohio. MarkWest Utica EMG will process gas produced by Antero and Rex Energy within certain dedicated acreage of the Utica Shale at its processing facilities in Seneca Township, in Ohio ("Seneca Complex") and will provide NGL fractionation and marketing services at the planned Harrison Fractionation Facility.

***Northeast Expansion***

In the fourth quarter 2012, we completed an additional cryogenic natural gas processing plant at the Langley processing complex with a capacity of 150 MMcf/d. The capacity at the Langley processing complex is supported by a long-term processing agreement with an affiliate of EQT Corporation ("EQT").

*East Texas Expansion*

During the fourth quarter 2012, we completed a 120 MMcf/d expansion of our processing facilities in East Texas, bringing the total processing capacity at this facility to 400 MMcf/d. The processing expansion is supported by long-term fee-based agreements with a number of producers including Anadarko Petroleum Corporation.

See *Our Operating Segments* below for additional discussion of our existing operations and planned expansions.

*Common Unit Offerings*

We issued a total of 32.2 million common units and received net proceeds of approximately $1.6 billion from registered public offerings of our common units in 2012. See Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the accounting treatment of the common unit offerings.

In November 2012, we entered into an Equity Distribution Agreement (the "EDA") with a financial institution ("Manager"). Pursuant to the terms of the EDA, we may from time to time, through the Manager as our sales agent, offer and sell common units having an aggregate offering price of up to $600 million. As of December 31, 2012, we have issued 0.1 million common units and received net proceeds of approximately $6 million under the Agreement. The Manager received $0.2 million for acting as our sales agent in connection with these issuances. For more information see Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

*Senior Notes Offerings and Tender Offers*

On August 10, 2012, we completed a public offering of $750 million in aggregate principal amount of 5.5% senior unsecured notes due February 2023 (the "2023A Senior Notes"), which were issued at 99.015% of par. Interest on the 2023A Senior Notes is payable semi-annually in arrears on February 15 and August 15, commencing February 15, 2013. We received net proceeds of approximately $730 million from the 2023A Senior Notes offering after deducting the underwriting fees and other third-party expenses. We used the net proceeds from the offering to repay borrowings under our revolving credit facility and for general partnership purposes, including, but not limited to, funding capital expenditures and general working capital.

In January 2013, we completed a public offering for $1 billion in aggregate principal amount of 4.5% senior unsecured notes due July 2023 (the "2023B Senior Notes"), which were issued at par. Interest on the 2023B Senior Notes is payable semi-annually in arrears on January 15 and July 15. We received net proceeds of approximately $986.9 million from the 2023B Senior Notes offering after deducting underwriting fees and other third-party expenses. A portion of the proceeds, together with cash on hand, was used to repurchase $81.1 million aggregate principal amount of our 8.75% senior notes due April 2018, $175 million of the outstanding principal amount of our 6.5% senior notes due August 2021 and $245 million of the outstanding principal amount of our 6.25% senior notes due June 2022, with the remainder used to fund our capital expenditure program and for general partnership purposes.

*Credit Facility*

On December 20, 2012 we amended our Credit Facility to increase the maximum permissible total leverage ratio from 5.25 to 1 to 5.5 to 1 for any quarter ending on or before December 31, 2013 as well as to permanently increase the EBITDA adjustment for material projects from 15% to 20%. On June 29, 2012, we amended our revolving Credit Facility to increase the borrowing capacity to $1.2 billion and retained the existing accordion option, providing for potential future increases of up to an aggregate of $250 million upon the satisfaction of certain requirements. The term of our Credit Facility was extended one year to September 2017. The actual borrowing capacity of our Credit Facility may be limited at times by financial covenant requirements. See Note 15 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details of our Credit Facility.

***Increase in MarkWest Utica EMG Funding Commitment***

In February 2013, we and EMG Utica, LLC ("EMG Utica") executed an Amended and Restated Limited Liability Company Agreement of MarkWest Utica EMG (the "Amended Utica LLC Agreement"). Pursuant to the Amended Utica LLC Agreement, EMG Utica's aggregate funding commitment has increased from $500 million to $950 million. Thereafter, EMG has the right to make additional contributions at varying rates and ultimately has the right to continue to make contributions to maintain EMG Utica's percentage ownership in MarkWest Utica EMG. *See Item 7. Management Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources* included in this Form 10-K for further discussion of the Amended Utica LLC Agreement.

**Business Strategy**

Our primary business strategy is to provide top-tier midstream services by developing and operating high-quality, strategically located assets in the liquids-rich areas of six core natural gas producing resource plays in the United States. We plan to accomplish this through the following:

- *Developing long-term integrated relationships with our producer customers.* As a top-rated midstream service provider, we develop long-term, integrated relationships with key producer customers as evidenced by our relationships with the primary producers in the Marcellus Shale, Utica Shale, Huron/Berea Shale, Haynesville Shale, Woodford Shale and Granite Wash formations. We continue to build relationships characterized by joint planning for the development of emerging resource plays and our commitment to grow to meet the specific needs of our customers.
- *Expanding operations through organic growth projects.* By expanding our existing infrastructure and customer relationships, we intend to continue growing in our primary areas of operation to meet the anticipated demand for additional midstream services. During 2012, we spent approximately $1.7 billion on capital expenditures to develop midstream infrastructure in the Marcellus and Utica Shale regions. We increased our processing capacity in the Marcellus region by 78% in 2012. In addition we completed the construction of an additional 150 MMcf/d of cryogenic processing capacity at our Langley, Kentucky facilities in our Northeast segment and an additional 120 MMcf/d of cryogenic processing capacity at our East Texas facilities in our Southwest Segment. We also executed long-term agreements with producers that will support the construction of 14 new processing plants primarily in the Marcellus and Utica Shale regions by the end of 2014, which will increase our total company-wide processing capacity by approximately 98%.
- *Expanding operations through strategic acquisitions.* We intend to continue pursuing strategic acquisitions of assets and businesses in our existing areas of operation that leverage our current asset base, personnel and customer relationships. We may also seek to acquire assets in certain regions outside of our current areas of operation. We believe that our capital structure positions us to compete more effectively for future acquisitions. For example, in 2012 we completed the Keystone Acquisition, in which we acquired natural gas processing and gas gathering assets located in the northwest Pennsylvania section of the Marcellus Shale. Commencing in 2013, the NGLs attributable to that gas will be fractionated in our Houston fractionation facility. The Keystone Acquisition supports our further expansion into the liquids-rich corridor of the

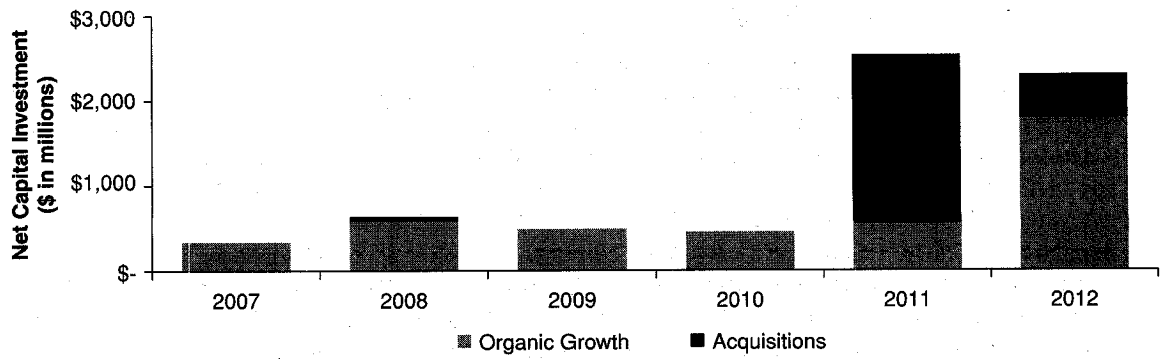
Marcellus Shale. In February 2011, we acquired natural gas processing and NGL pipeline assets located in Kentucky and West Virginia (the "Langley Acquisition") for processing gas produced in the Huron/Berea Shale and transporting NGLs to our Siloam fractionation facility.

- *Maintaining our financial flexibility.* Our goal is to maintain a capital structure with approximately equal amounts of debt and equity financing on a long-term basis. During 2012, we raised approximately $2.4 billion of capital by strategically accessing the debt and equity markets to fund our acquisition and planned expansion projects. See Note 15, Note 16 and Note 28 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the recent transactions related to our senior notes and common unit offerings. We also entered into amendments to our Credit Facility to expand the total borrowing capacity from $900 million to $1.2 billion, retain the existing accordion option, extend the term to September 2017, and to increase the leverage ratio from 5.25 to 1 to 5.5 to 1 for any quarter ending on or before December 31, 2013. As of December 31, 2012, we and our wholly-owned subsidiaries had approximately $313.0 million of cash and cash equivalents and we had approximately $1,188.4 million of unused capacity under our Credit Facility, of which approximately $680 million was available for borrowing based on financial covenant requirements. Additionally, the full amount of unused capacity is available for borrowing on a short-term basis to provide financial flexibility within a given fiscal quarter. We believe that our Credit Facility, our ability to issue additional partnership units and long-term debt, our strong relationships with our existing joint venture partners and the sale of non-strategic assets will provide us with the financial flexibility to facilitate the execution of our business strategy.

- *Reducing the sensitivity of our cash flows to commodity price fluctuations.* We intend to continue to secure long-term, fee-based contracts in order to further reduce our exposure to short-term changes in commodity prices. We estimate that fee-based contracts will account for approximately 60% of our net operating margin by the end of 2013. We also engage in risk management activities in order to reduce the effect of commodity price volatility related to future natural gas, NGL and crude oil transactions. We may utilize a combination of fixed-price forward contracts, fixed-for-floating price swaps and options available in the OTC market. We monitor these activities to ensure compliance with our commodity risk management policy. See Note 6 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of our commodity risk management policy.

- *Increasing utilization of our facilities.* We seek to increase the utilization of our existing facilities by providing additional services to our existing customers and by establishing relationships with new customers. We also continue to develop additional capacity at many of our facilities, which enables us to increase throughput with minimal incremental costs.

Execution of our business strategy has allowed us to grow substantially since our inception. The majority of our growth since 2007 has focused on the development of midstream services to support the increase in NGL production and natural gas supply in liquids-rich resource plays. As a result, we now have a strong presence in the Marcellus Shale, Utica Shale, Huron/Berea Shale, Haynesville Shale, Woodford Shale and Granite Wash formation; six emerging resource plays that are expected to be a significant source of domestic natural gas and NGL production. The following table summarizes the magnitude of our expenditures over time on acquisitions of businesses and non-controlling interests and organic growth capital, including equity investments. The amounts include the portion of our growth projects funded by contributions from our current and former joint venture partners.




We believe that the following competitive strengths position us to continue to successfully execute our primary business strategy:

- *Leading position in the liquids-rich areas of the northeast United States.* Since our inception, we have been the largest processor and fractionator in the northeast United States and we continue to strengthen our position in these critical growth areas that is driven by the development of the Marcellus, Huron/Berea, and Utica shale formations. We are the largest processor and fractionator in the Marcellus Shale and we have announced plans that we believe allows us to be the largest processor and fractionator in the Utica Shale by 2014. At December 31, 2012 our Northeast, Liberty and Utica segments have combined processing capacity in excess of 1.8 Bcf/d and combined fractionation capacity of nearly 85,000 barrels per day, as well as an integrated NGL pipeline, storage and marketing infrastructure. Our processing and fractionation capacity is supported by strategic long-term agreements that include significant acreage dedications from key producers. We believe our significant presence and asset base provide us with a competitive advantage in capturing and contracting for new supplies of natural gas as the production from these shale formations continues to be developed.

- *Strategic and growing position with high-quality assets in the Southwest.* Our internal growth projects have allowed us to expand our presence in several long-lived natural gas supply basins in the Southwest, particularly in Texas and Oklahoma. All of our major operating assets and growth projects in this region have been characterized by several common critical success factors that include:

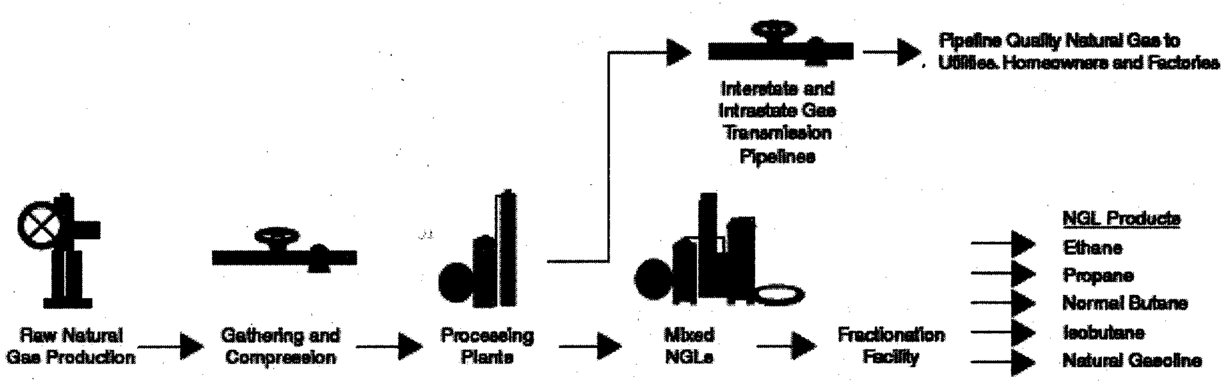
  - an existing strong competitive position;
  - access to a significant reserve or customer base with a stable or growing production profile;
  - ample opportunities for long-term continued organic growth;
  - ready access to markets; and
  - close proximity to other expansion opportunities.

  Specifically, our East Texas and Appleby gathering systems are located in the East Texas Basin, producing from or with direct access to the Cotton Valley, Pettit and Travis Peak reservoirs as well as the Haynesville and Bossier Shales. Our Foss Lake gathering system and the associated expanded Arapaho gas processing plants are located in the Anadarko Basin in Oklahoma and are connected to the Granite Wash area in the Texas panhandle. Additionally, we have a significant gathering system located in the Woodford Shale reservoir. Our gathering systems are relatively new and provide producers with low-pressure and fuel-efficient service, a significant competitive advantage for us over many competing gathering systems in those areas. We also provide high quality processing and fractionation service to six strategically located gulf coast refineries that we believe will continue to play a key role in supporting the long-term U.S. demand for refined petroleum products.

- *Long-term Contracts.* We believe our long-term contracts, which we define as contracts with remaining terms of four years or more, lend greater stability to our cash flow profile. All of the long-term fee-based contracts supporting the expansion of our Liberty and Utica segments have remaining terms between 8 to 15 years. In our Southwest segment, approximately 38% of our current gathering volumes in East Texas are under contract for longer than four years as of December 31, 2012; approximately 53% of our current daily throughput in the Western Oklahoma gathering system and Arapaho processing plants are subject to contracts with remaining terms of more than four years; and approximately 91% of our throughput in the Woodford gathering system is subject to contracts with remaining terms of more than four years. Also in our Southwest segment, our processing and fractionation contracts with refinery customers that account for 74% of the volumes processed at our processing facilities in Corpus Christi, TX have remaining terms of at least six years and we have two lateral natural gas transmission pipelines that operate under fixed-fee contracts with remaining terms of approximately eight and 16 years. In Appalachia, our natural gas processing and NGL fractionation and exchange contracts with 61% of NGL volumes are subject to contracts with remaining terms of at least nine years.
- *Experienced management with operational, technical and acquisition expertise.* Each member of our executive management team has substantial experience in the energy industry and has interests aligned with those of our common unitholders through our long-term incentive compensation plans. Our facility managers have extensive experience operating our facilities. Our management team's operational and technical expertise has enabled us to upgrade our existing facilities, as well as to design and build new midstream infrastructure facilities. Since our initial public offering in May 2002, our management team has utilized a disciplined approach to analyze and evaluate numerous acquisition opportunities, and has completed 14 acquisitions as of December 31, 2012, including the acquisitions of the gas gathering and processing assets from Keystone effective May 29, 2012 and the non-controlling interest in MarkWest Liberty Midstream effective December 31, 2011.

**Industry Overview**

We provide services in the midstream sector of the natural gas industry which includes natural gas gathering, transportation, processing and fractionation. The following diagram illustrates the typical natural gas gathering, natural gas processing and NGL fractionation processes:



The natural gas production process begins with the drilling of wells into gas-bearing rock formations. The gathering process begins when a producing well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Historically, the majority of the domestic on-shore natural gas supply has been produced from conventional reservoirs that are characterized by large pockets of natural gas that are accessed successfully using vertical drilling techniques. In the past decade, the supply of natural gas production from the conventional sources has declined as these reservoirs are being depleted. Due to advances in well completion technology and horizontal drilling techniques, unconventional sources such as shale, tight sand and coal bed methane formations have become the most significant source of current and expected future natural gas production.

Natural gas has a widely varying composition, depending on the field, formation reservoir or facility from which it is produced. The principal constituents of natural gas are methane and ethane. Some natural gas also contains varying amounts of heavier components, such as propane, butane, natural gasoline and inert substances that may be removed by any number of processing methods.

Most natural gas produced at the wellhead is not suitable for long-haul pipeline transportation or commercial use. It must be gathered, compressed and transported via pipeline to a central facility, and potentially processed and treated. Natural gas processing and treating involves the separation of raw natural gas into pipeline-quality natural gas, principally methane, and a mixed NGL stream, as well as the removal of contaminants that may interfere with pipeline transportation or the end-use of the gas. Our business includes providing these services either for a fee or a percentage of the NGLs removed or gas units processed. The industry as a whole is characterized by regional competition, based on the proximity of gathering systems and processing plants to producing natural gas wells, or to facilities that produce natural gas as a byproduct of refining crude oil. Due to the shift in the source of natural gas production, midstream providers with a significant presence in the emerging resource plays will likely have a competitive advantage.

The removal and separation of individual hydrocarbons and other constituents by processing is possible because of differences in physical properties. Each component has a distinctive weight, boiling point, vapor pressure and other physical characteristics. Natural gas may also be diluted or contaminated by water, sulfur compounds, carbon dioxide, nitrogen, helium or other components.

After being separated from natural gas at the processing plant, the mixed NGL stream is typically transported to a centralized facility for fractionation. Fractionation is the process by which NGLs are further separated into individual, more marketable components, primarily ethane, propane, normal butane, isobutane and natural gasoline. Fractionation systems typically exist either as an integral part of a gas processing plant or as a central fractionator, often located many miles from the primary production and processing facility. A central fractionator may receive mixed streams of NGLs from many processing plants.

Basic NGL products and their typical uses are discussed below. The basic products are sold in all of our segments except as noted.

- *Ethane* is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.

  Ethane is not currently recovered from the natural gas stream in our Northeast and Liberty segments. However, we are developing projects that would allow us to recover ethane and provide our producer customers with access to markets for the ethane produced in the Liberty segment, which are expected to begin operations in mid-2013. See *Our Operating Segments—Liberty Segment* below in this Item 1 for further discussion of our ethane solution.

- *Propane* is used for heating, engine and industrial fuels, agricultural burning and drying and as a petrochemical feedstock for the production of ethylene and propylene. Propane is principally used as a fuel in our operating areas.
- *Normal butane* is mainly used for gasoline blending, as a fuel gas, either alone or in a mixture with propane, and as a feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber.
- *Isobutane* is primarily used by refiners to enhance the octane content of motor gasoline.
- *Natural gasoline* is principally used as a motor gasoline blend stock or petrochemical feedstock.

The other primary products produced and sold from our Javelina facility are discussed below.

- *Ethylene* is primarily used in the production of a wide range of plastics and other chemical products.
- *Propylene* is primarily used in manufacturing plastics, synthetic fibers and foams. It is also used in the manufacture of polypropylene, which has a variety of end-uses including packaging film, carpet and upholstery fibers and plastic parts for appliances, automobiles, houseware and medical products.

**Our Operating Segments**

We conduct our operations in the following operating segments: Southwest, Northeast, Liberty and Utica. Our assets and operations in each of these segments are described below.

***Southwest Segment***

- *East Texas.* We own a system that consists of natural gas gathering pipelines, centralized compressor stations, a natural gas processing complex and an NGL pipeline. The East Texas system is located in Panola, Harrison and Rusk Counties and services the Carthage Field. Producing formations in Panola County consist of the Cotton Valley, Pettit, Travis Peak, Haynesville and Bossier formations. For natural gas that is processed in this area, we purchase NGLs from the producers under percent-of-proceeds arrangements, or we transport and process volumes for a fee. We completed an additional 120 MMcf/d cryogenic processing plant during the fourth quarter of 2012, increasing total processing capacity in East Texas to 400 MMcf/d. We also expanded gathering capacity in East Texas by 140 MMcf/d in the third quarter of 2012 and residue gas outlet capacities by 60 MMcf/d in the fourth quarter of 2012. Additional NGL outlet capacity that will allow us to market the additional NGLs produced as a result of the expansion is expected to be completed in the fourth quarter of 2013 and will allow us to fully utilize the expanded processing capacity.

  Approximately 83% of our natural gas volumes in the East Texas System in 2012 resulted from contracts with six producers. We sell substantially all of the purchased and retained NGLs produced at our East Texas processing facility to Targa Resources Partners, L.P. ("Targa") under a long-term contract. Such sales represented approximately 11.8% of our consolidated revenue in 2012. The initial term of the Targa agreement expires in December 2015.

- *Oklahoma.* We own an extensive natural gas gathering system in the Woodford Shale play in the Arkoma Basin of southeast Oklahoma. We own a 40% non-operating membership interest in Centrahoma Processing L.L.C. ("Centrahoma"), a joint venture with Atlas Pipeline Partners, L.P. ("Atlas") that is accounted for using the equity method. The liquids-rich natural gas gathered in the Woodford system is processed through Centrahoma or other third-party processors. We have agreed to fund our share of a 120 MMcf/d processing plant expansion at Centrahoma in order to support the liquids-rich drilling programs in the Woodford Shale. The expansion is expected to be operational in the first quarter of 2014. In addition, we own gas gathering systems in Western Oklahoma and the Texas panhandle, which are both connected to a natural gas processing complex in Western Oklahoma. The gathering portion consists of a pipeline system that is connected to natural gas wells and associated compression facilities. The majority of the gathered gas is ultimately compressed and delivered to the processing complex.

Approximately 74% of our Oklahoma volumes in 2012 resulted from contracts with four producers. We sell substantially all of the NGLs produced in the Western Oklahoma processing complex to ONEOK Hydrocarbon L.P. ("ONEOK") under a long-term contract. Such sales represented approximately 12.6% of our consolidated revenue in 2012. The initial term of the ONEOK agreement expires in October 2021.

Through our joint venture, MarkWest Pioneer L.L.C. ("MarkWest Pioneer"), we operate the Arkoma Connector Pipeline, a 50-mile FERC-regulated pipeline that interconnects with the Midcontinent Express Pipeline and Gulf Crossing Pipeline at Bennington, Oklahoma and is designed to provide approximately 638,000 Dth/d of Woodford Shale takeaway capacity. We completed an additional interconnect with the Natural Gas Pipeline of America L.L.C ("NGPL Pipeline") in Bennington, Oklahoma in April 2012. For a complete discussion of the formation of, and accounting treatment for, MarkWest Pioneer, see Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

- *Javelina.* We own and operate the Javelina processing and fractionation facility in Corpus Christi, Texas that treats, processes and fractionates off-gas from six local refineries operated by three different refinery customers. We have a product supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for all of the product processed by the SMR, see Note 5 of the accompanying Notes to Consolidated Financial Statements for further discussion of this agreement and the related sale of the steam methane reformer (the "SMR Transaction"). The product received under this agreement is sold to a refinery customer pursuant to a corresponding long-term agreement.

- *Other Southwest.* We own a number of natural gas gathering systems and lateral pipelines located in Texas, Louisiana and New Mexico, including the Appleby gathering system in Nacogdoches County, Texas. We gather a significant portion of the natural gas produced from fields adjacent to our gathering systems, including from wells targeting the Haynesville Shale. In many areas we are the primary gatherer, and in some of the areas served by our smaller systems we are the sole gatherer. Our Hobbs, New Mexico natural gas lateral pipeline is subject to regulation by FERC.

  The Other Southwest area does not have any customers that we consider to be significant to the Southwest segment revenue or our consolidated revenue.

***Northeast Segment***

- *Kentucky and southern West Virginia.* Our Northeast segment assets include the Kenova, Boldman, Cobb, Kermit and the Langley natural gas processing complexes, an NGL pipeline, and the Siloam NGL fractionation facility. During the fourth quarter of 2012, we completed an additional cryogenic natural gas processing plant at the Langley processing complex with a capacity of 150 MMcf/d. In addition, we have two caverns for storing propane at our Siloam facility and additional propane storage capacity under a long-term firm-capacity agreement with a third-party. Including our presence in the Marcellus Shale (see *Liberty Segment* below), we are the largest processor and fractionator of natural gas in the Northeast, with fully integrated processing, fractionation, storage and marketing operations.

- *Michigan.* We own and operate a FERC-regulated crude oil pipeline in Michigan ("Michigan Crude Pipeline") providing interstate transportation service.

  The Northeast Segment has one customer that accounts for a significant portion of its segment revenue, but this customer does not account for a significant portion of our consolidated revenue.

***Liberty Segment***

- *Marcellus Shale.* We provide extensive natural gas midstream services in southwest Pennsylvania and northern West Virginia through MarkWest Liberty Midstream. With gathering capacity of 525 MMcf/d and current processing capacity of over 1.1 Bcf/d, we are the largest processor of natural gas in the Marcellus Shale, with fully integrated gathering, processing, fractionation, storage and marketing operations that are critical to the liquids-rich gas development in the northeast United States.

  The gathering, processing and fractionation facilities currently operating and under construction in our Liberty segment consist of the following:

  *Natural Gas Gathering*

  - Existing gathering system delivering to our Houston Complex.
  - Existing gathering lines acquired in the Keystone Acquisition.
  - Existing gathering system completed in the fourth quarter of 2012, delivering to our Sherwood Complex.

  *Natural Gas Processing*

  - 355 MMcf/d of current cryogenic processing capacity at our Houston Complex.
  - 270 MMcf/d of current cryogenic processing capacity at our Majorsville Complex.
  - 200 MMcf/d of current cryogenic processing capacity at our Mobley Complex.
  - 90 MMcf/d of cryogenic processing capacity at our Keystone Complex, which we acquired in the Keystone Acquisition.
  - 200 MMcf/d of current cryogenic processing capacity at our Sherwood Complex completed in the fourth quarter of 2012.
  - 800 MMcf/d expansion of our Majorsville Complex under construction that is supported by long-term agreements with Chesapeake Energy Corporation, CONSOL Energy Inc., Noble Energy Inc. and Range Resources Corporation. The Majorsville expansion includes four 200 MMcf/d processing plants that are expected to commence operation in 2013 and 2014 and will bring our total cryogenic processing capacity at Majorsville to approximately 1.1 Bcf/d.
  - 320 MMcf/d cryogenic processing capacity under construction at our Mobley Complex. A 120 MMcf/d facility is expected to be completed during the first quarter of 2013 and an additional 200 MMcf/d facility is expected to be operational during the fourth quarter of 2013. The expansion facilities are supported by long-term fee-based agreements with EQT and Magnum Hunter Resources Corporation.
  - 400 MMcf/d cryogenic processing capacity under construction at our Sherwood Complex, 200 MMcf/d of which is expected to be completed in the second quarter of 2013 and 200 MMcf/d of which is expected to be completed in the third quarter of 2013. The

expansion plans are based, in part, on Antero's decision to support the additional capacity under a long-term fee-based processing agreement.

- 120 MMcf/d cryogenic processing capacity under construction in Butler County, Pennsylvania, which is expected to commence operation in the first quarter of 2014. Based on producers' production, we may expand our Keystone Complex by an additional 200 MMcf/d as soon as 2014.

By the end of 2014, MarkWest Liberty Midstream is expected to have approximately 3.0 Bcf/d of cryogenic processing capacity that is supported primarily by long-term fee-based agreements with our producer customers.

*NGL Gathering, Fractionation and Market Outlets*

- NGLs produced at the Majorsville Complex are delivered through an NGL pipeline ("Majorsville Pipeline") to the Houston Complex for exchange for fractionated products. The NGL pipeline from our Mobley Complex to the Majorsville Complex was completed in the fourth quarter of 2012. The NGL pipeline connecting the Sherwood Complex to the Mobley Complex is under construction and is expected to be completed in the first quarter of 2013. Additionally, we are expanding our NGL gathering system into Northwest Pennsylvania to allow us to gather, fractionate and market NGLs produced at our Keystone Complex and at a processing facility owned by XTO that is expected to begin operations in early 2013. We will gather NGLs for XTO and exchange them for fractionated NGL products pursuant to a long-term fee-based agreement. The NGLs will be transported by truck to the Houston Complex for fractionation until the NGL pipeline is complete in late 2013.
- Existing propane-plus fractionation facility at our Houston Complex with a design capacity of 60,000 Bbl/d.
- Existing interconnect with a key interstate pipeline providing a market outlet and storage for the propane produced from this region.
- Existing agreements to access international markets. Propane is currently being transported by truck to a third-party terminal near Philadelphia, Pennsylvania where it is loaded onto marine vessels and delivered to international markets. We plan to add rail deliveries to the terminal in the next several months as rail unloading capabilities are expanded. As discussed below, we will also have the ability to deliver propane to Sunoco's terminal in Philadelphia via pipeline once the Mariner East pipeline is placed into service.
- Existing extensions of our NGL gathering system to receive NGLs produced at a third-party's Fort Beeler processing plant and our Mobley Complex. This project allows our producer customers at the Mobley Complex as well as certain producers at the third party's plant to benefit from our integrated NGL fractionation and marketing operations.
- Existing twelve bay truck loading and unloading facility at our Houston Complex. The unloading facility allows for regional marketing of purity NGLs and the unloading facility allows for the receipt of raw NGLs for fractionation and marketing.
- Existing 200 railcar loading facility at our Houston Complex that expands our market access and allows for long-haul, cost-effective transportation of purity NGLs.

We continue to evaluate additional projects to expand our gathering, processing, fractionation, and marketing operations in the Marcellus Shale.

*Ethane Recovery and Associated Market Outlets*

Due to increased natural gas production from the liquids-rich area of the Marcellus Shale, natural gas processors must begin to recover a significant amount of ethane from the gas stream to meet the pipeline gas quality specifications for residue gas and to allow for the ability to benefit from price uplift received from the sale of ethane. We are developing solutions that will have the capability to recover and fractionate ethane, and provide access to ethane markets in North America and internationally. The primary components of our ethane recovery, fractionation and marketing solutions consist of the following:

- Two de-ethanization facilities totaling 76,000 Bbl/d are under construction at our Houston and Majorsville Complexes that are expected to be completed by mid-2013.
- A third de-ethanization facility at our Majorsville Complex that would increase production capacity of purity ethane to approximately 115,000 Bbl/d in first quarter 2014.
- A joint pipeline project with Sunoco that is currently under construction to deliver Marcellus ethane to the Sarnia, Ontario, Canadian markets ("Mariner West"). Mariner West will utilize new and existing pipelines and is anticipated to have an initial capacity to transport up to 50,000 Bbl/d of ethane in the third quarter of 2013 with the ability to expand to support higher volumes as needed.
- Mariner East, a Sunoco pipeline and marine project that is expected to begin at our Houston Complex, is intended to deliver Marcellus purity ethane and purity propane to the Gulf Coast and international markets. Mariner East, for which we have made a 5,000 bbl/d commitment, is expected to begin delivering propane in the second half of 2014 and ethane in the first half of 2015.
- Connection to Enterprise Products Partners L.P.'s NGL pipeline from Appalachia to Texas ("ATEX Pipeline"). We expect to begin delivering ethane to the ATEX Pipeline in the first quarter 2014.

There is one individual customer that accounted for approximately 56% of our Liberty segment revenue during the year ended December 31, 2012. We consider this customer to be significant to the Liberty segment revenue but not to our consolidated revenue.

***Utica Segment***

Effective January 1, 2012, we formed MarkWest Utica EMG, a joint venture with EMG focused on the development of fully integrated midstream services in the Utica Shale in eastern Ohio. The current Utica development plan includes:

*Natural Gas Processing*

- 325 MMcf/d processing in our Cadiz Complex planned and expected to be complete in 2014. It began the first phase of operations in the fourth quarter of 2012 with interim mechanical refrigeration processing capacity of 60 MMcf/d.
- 400 MMcf/d processing in our Seneca Complex is expected to begin the first phase of operations in the third quarter of 2013 with processing capacity of 200 MMcf/d.

*NGL Gathering, Fractionation and Market Outlets*

- 100,000 Bbl/d of NGL fractionation, storage, and marketing capabilities in Harrison County for propane and heavier components (the "Hopedale Fractionation Facility"). The Hopedale Fractionation Facility will be jointly owned by MarkWest Utica EMG and MarkWest Liberty Midstream and is expected to begin operations in the first quarter of 2014.

- Both processing complexes are expected to be connected via an NGL gathering pipeline system to the Hopedale Fractionation Facility that is expected to be operational by the first quarter of 2014.
- From the Hopedale Fractionation Facility we plan to market NGLs by truck, rail and pipeline. A rail car loading facility that can accommodate 200 rail cars and an eight bay truck loading and unloading facility are under construction at the Hopedale Fractionation Facility and are expected to be complete by mid-2013. Additionally, the Hopedale Fractionation Facility is expected to be connected to our extensive processing and NGL pipeline network in our Liberty segment and provide for the integrated operation of the two largest fractionation complexes in the northeast United States by the first quarter of 2014.

*Ethane Recovery and Associated Market Outlets*

- At our Cadiz Complex we are also constructing de-ethanization capacity and a connection to the ATEX Pipeline. We expect to begin delivering ethane to the ATEX Pipeline in the first quarter of 2014.

The following summarizes the percentage of our revenue and net operating margin (a non-GAAP financial measure, see *Non-GAAP Measures* discussion below) generated by our assets, by segment, for the year ended December 31, 2012:

| | Southwest | Northeast | Liberty | Utica |
|---|---|---|---|---|
| Segment revenue | 61% | 16% | 23% | <1% |
| Net operating margin | 54% | 18% | 28% | <1% |

For further financial information regarding our segments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included in this Form 10-K.

*Equity Investment in Unconsolidated Affiliate*

We own a 40% non-operating membership interest in Centrahoma, a joint venture with Atlas that is accounted for using the equity method. Centrahoma owns certain processing plants in the Arkoma Basin and Atlas operates an additional processing plant that is not owned by Centrahoma but is located adjacent to and operates in conjunction with the Centrahoma plants. We have signed long-term agreements to dedicate the processing rights for our natural gas gathering system in the Woodford Shale to Centrahoma and to Atlas' independently owned processing facility. This processing facility is being expanded by an additional 120 MMcf/d and is expected to be complete by the first quarter of 2014. The financial results for Centrahoma are included in *Earnings from unconsolidated affiliates* and are not included in our segment results.

**Our Contracts**

We generate the majority of our revenues and net operating margin (a non-GAAP financial measure, see *Non-GAAP Measures* below for discussion and reconciliation of net operating margin) from natural gas gathering, transportation and processing; NGL gathering, transportation, fractionation, exchange, marketing and storage; and crude oil gathering and transportation. We enter into a variety of contract types. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described below. We provide services under the following types of arrangements:

- *Fee-based arrangements:* Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, processing and transportation of natural gas; transportation, gathering, fractionation, exchange, marketing and storage of NGLs; and gathering and transportation of crude oil. The revenue we earn from these arrangements is generally directly related to the volume of natural gas, NGLs or crude oil that flows through our systems and facilities and is not directly dependent on commodity prices. If a sustained decline in commodity prices were to result in a decline in volumes, however, our revenues from these arrangements would be reduced. In certain cases, our arrangements provide for minimum annual payments, fixed demand charges or fixed returns on gathering system expenditures.

- *Percent-of-proceeds arrangements:* Under percent-of-proceeds arrangements, we gather and process natural gas on behalf of producers, sell the resulting residue gas, condensate and NGLs at market prices and remit to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, we deliver an agreed-upon percentage of the residue gas and NGLs to the producer and sell the volumes we keep to third parties at market prices. The percentage of volumes that we retain can be either fixed or variable. Generally, under these types of arrangements, our revenues and net operating margins increase as natural gas, condensate and NGL prices increase and our revenues and net operating margins decrease as natural gas, condensate and NGL prices decrease.
- *Percent-of-index arrangements:* Under percent-of-index arrangements, we purchase natural gas at either (i) a percentage discount to a specified index price, (ii) a specified index price less a fixed amount or (iii) a percentage discount to a specified index price less an additional fixed amount. We then gather and deliver the natural gas to pipelines where we resell the natural gas at the index price, or at a different percentage discount to the index price. With respect to (i) and (iii) above, the net operating margins we realize under the arrangements decrease in periods of low natural gas prices because these net operating margins are based on a percentage of the index price. Conversely, our net operating margins increase during periods of high natural gas prices.
- *Keep-whole arrangements:* Under keep-whole arrangements, we gather natural gas for the producer, process the natural gas and sell the resulting condensate and NGLs to third parties at market prices. Because the extraction of NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require us to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the relative price of NGLs to natural gas. Accordingly, under these arrangements our revenues and net operating margins increase as the price of condensate and NGLs increases relative to the price of natural gas and decrease as the price of natural gas increases relative to the price of condensate and NGLs.

Under certain contracts, we are allowed to retain a fixed percentage of the volume gathered to cover the compression fuel charges and deemed-line losses. To the extent that we operate our gathering systems more or less efficiently than specified per contract allowance, we retain the benefit or loss for our own account.

The terms of our contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements. Our contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of changes in producer preferences, our expansion in regions where some types of contracts are more common and other market factors, including current market and financial conditions which have increased the risk of volatility in oil, natural gas and NGL prices. Any change in mix may influence our long-term financial results.

**Non-GAAP Measures**

In evaluating the Partnership's financial performance, management utilizes the segment performance measures, segment revenues and operating income before items not allocated to segments. These financial measures are presented in Note 23 to the accompanying consolidated financial statements and are considered non-GAAP financial measures when presented outside of the notes to the consolidated financial statements. The use of these measures allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. See Note 23 to the accompanying consolidated financial statements for the reconciliations of segment revenue and operating income before items not allocated to segments to the respective most comparable GAAP measure.

Management evaluates contract performance on the basis of net operating margin (a non-GAAP financial measure), which is defined as revenue, excluding any derivative gain (loss), less purchased product costs, excluding any derivative gain (loss). These charges have been excluded for the purpose of enhancing the understanding by both management and investors of the underlying baseline operating performance of our contractual arrangements, which management uses to evaluate our financial performance for purposes of planning and forecasting. Net operating margin does not have any standardized definition and, therefore, is unlikely to be comparable to similar measures presented by other reporting companies. Net operating margin results should not be evaluated in isolation of, or as a substitute for, our financial results prepared in accordance with GAAP. Our use of net operating margin and the underlying methodology in excluding certain charges is not necessarily an indication of the results of operations expected in the future, or that we will not, in fact, incur such charges in future periods.

The following is a reconciliation of net operating margin to income from operations, the most comparable GAAP financial measure of this non-GAAP financial measure (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Segment revenue | $1,402,672 | $1,549,819 | $1,241,563 |
| Purchased product costs | (530,328) | (682,370) | (578,627) |
| Net operating margin | 872,344 | 867,449 | 662,936 |
| Facility expenses | (208,385) | (173,598) | (151,449) |
| Derivative gain (loss) | 69,126 | (75,515) | (80,350) |
| Revenue deferral adjustment | (7,441) | (15,385) | — |
| Selling, general and administrative expenses | (94,116) | (81,229) | (75,258) |
| Depreciation | (189,549) | (149,954) | (123,198) |
| Amortization of intangible assets | (53,320) | (43,617) | (40,833) |
| Loss on disposal of property, plant and equipment | (6,254) | (8,797) | (3,149) |
| Accretion of asset retirement obligations | (677) | (1,190) | (237) |
| Income from operations | $ 381,728 | $ 318,164 | $ 188,462 |

The following table does not give effect to our active commodity risk management program. For further discussion of how we manage commodity price volatility for the portion of our net operating margin that is not fee-based, see Note 6 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K. We manage our business by taking into account the partial offset of short natural gas positions primarily in our Southwest segment. The calculated percentages for net operating margin for percent-of-proceeds, percent-of-index and keep-whole contracts reflect the partial offset of our natural gas positions. The calculated percentages are less than one percent for percent-of-index due to the offset of our natural gas positions and, therefore, not meaningful to the table below. For the year ended December 31, 2012, we calculated the following approximate percentages of our segment net operating margin from the following types of contracts:

| | Fee-Based | Percent-of-Proceeds(1) | Keep-Whole(2) |
|---|---|---|---|
| Southwest | 44% | 33% | 23% |
| Northeast | 17% | 13% | 70% |
| Liberty | 75% | 25% | 0% |
| Utica | 100% | 0% | 0% |

(1) Includes condensate sales and other types of arrangements tied to NGL prices.

(2) Includes condensate sales and other types of arrangements tied to both NGL and natural gas prices.

**Competition**

In each of our operating segments, we face competition for natural gas gathering, crude oil transportation and in obtaining natural gas supplies for our processing and related services; in obtaining unprocessed NGLs for gathering and fractionation; and in marketing our products and services. Competition for natural gas supplies is based primarily on the location of gas gathering facilities and gas processing plants, operating efficiency and reliability and the ability to obtain a satisfactory price for products recovered. Competitive factors affecting our fractionation services include availability of capacity, proximity to supply and industry marketing centers and cost efficiency and reliability of service. Competition for customers to purchase our natural gas and NGLs is based primarily on price, delivery capabilities, flexibility and maintenance of high-quality customer relationships.

Our competitors include:

- natural gas midstream providers, of varying financial resources and experience, that gather, transport, process, fractionate, store and market natural gas and NGLs;
- major integrated oil companies;
- medium and large sized independent exploration and production companies; and
- major interstate and intrastate pipelines.

Some of our competitors operate as master limited partnerships and may enjoy a cost of capital comparable to and, in some cases, lower than ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and contracted supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas.

We believe that our customer focus in all segments, demonstrated by our ability to offer an integrated package of services and our flexibility in considering various types of contractual arrangements, allows us to compete more effectively. Additionally, we have critical connections to the key market outlets for NGLs and natural gas in each of our segments. In the Southwest segment, our major gathering systems are relatively new, located primarily in the heart of shale plays with significant long-term growth opportunities and provide producers with low-pressure and fuel-efficient service, which differentiates us from many competing gathering systems in those areas. The strategic location of our assets and the long-term nature of our contracts also provide a significant competitive advantage. In the Northeast segment, our operational experience of more than 20 years as the largest processor and fractionator and our existing presence in the Appalachian Basin provide a significant competitive advantage. In the Liberty segment, our early entrance in the liquids-rich corridors of the Marcellus and Utica Shales through our strategic gathering and processing agreements with key producers enhances our competitive position to participate in the further development of these resource plays.

**Seasonality**

Our business can be affected by seasonal fluctuations in the demand for natural gas and NGLs and the related fluctuations in commodity prices caused by various factors such as changes in transportation and travel patterns and variations in weather patterns from year to year. Our Northeast segment could be particularly impacted by seasonality as the majority of its revenues are generated by NGL sales. However, we manage the seasonality impact through the execution of our marketing strategy. We have access to approximately 50 million gallons of propane storage capacity in the northeast region provided by our own storage facilities and a firm capacity arrangement with a third-party which provides us with flexibility to manage the seasonality impact. Overall, our exposure to the seasonal fluctuations in the commodity markets is declining due to our growth in fee-based business.

**Regulatory Matters**

Our operations are subject to extensive regulations. The failure to comply with applicable laws and regulations or to obtain, maintain and comply with requisite permits and authorizations can result in substantial penalties and other costs to the Partnership. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, reliance on the following discussion of certain laws and regulations should not be considered an exhaustive review of all regulatory considerations affecting our operations.

*FERC-Regulated Natural Gas Pipelines.* Our natural gas pipeline operations are subject to federal, state and local regulatory authorities. Specifically, our Hobbs, New Mexico natural gas pipeline and our Arkoma Connector natural gas pipeline in Oklahoma are subject to regulation by FERC, and it is possible that we may construct additional gas pipelines in the future that may be subject to such regulation. Federal regulation extends to various matters including:

- rates and rate structures;
- return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction, expansion, operation and disposition of assets;
- affiliate interactions; and
- to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act ("NGA"), FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services and various other matters. Natural gas companies may not charge rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits FERC regulated natural gas facilities from unduly preferring, or unduly discriminating against, any person with respect to pipeline rates or terms and conditions of service or other matters. The rates and terms and conditions for our service will be found in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot be assured that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity and transportation facilities. Any successful complaint or protest against our rates or loss of market-based rate authority by FERC could have an adverse impact on our revenues associated with providing interstate gas transportation services.

*Energy Policy Act of 2005.* On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 ("2005 EPAct"). Under the 2005 EPAct, FERC may impose civil penalties of up to $1,000,000 per day for each current violation of the Natural Gas Policy Act of 1978 ("NGA"). The 2005 EPAct also amends 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. FERC issued Order No. 670 to implement the anti-market manipulation provision of 2005 EPAct. This order makes it unlawful for gas pipelines and storage companies that provide interstate services to: (i) directly or indirectly, use or employ any device, scheme or artifice to defraud 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; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's enforcement authority.

*Standards of Conduct.* In 2008, FERC issued standards of conduct for transmission providers in Order 717, as amended and clarified in subsequent orders on rehearing to regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates based on an employee separation approach. A "Transmission Provider" includes an interstate natural gas pipeline that provides open access transportation pursuant to FERC's regulations. Under these rules, a Transmission Provider's transmission function employees (including the transmission function employees of any of its affiliates) must function independently from the Transmission Provider's marketing function employees (including the marketing function employees of any of its affiliates).

*Market Transparency Rulemakings.* In 2007, FERC issued Order 704, as amended and clarified in subsequent orders on rehearing, whereby 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 and natural gas marketers, 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 to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704. The Partnership typically files the report required by Order 704 on behalf of its subsidiaries that engage in reportable transactions. On November 15, 2012, FERC issued a Notice of Inquiry in which it requested comments on whether it should propose to require the quarterly reporting of certain data relating to next-day and next-month transactions.

*Intrastate Natural Gas Pipeline Regulation.* Some of our intrastate gas pipeline facilities are subject to various state laws and regulation that affect the rates we charge and terms of service. Although state regulation is typically less onerous than FERC, state regulation typically requires pipelines to charge just and reasonable rates and to provide service on a non-discriminatory basis. The rates and service of an intrastate pipeline generally are subject to challenge by complaint. Additionally, FERC has adopted certain regulations and reporting requirements applicable to intrastate natural gas pipelines (and Hinshaw natural gas pipelines) that provide certain interstate services subject to FERC's jurisdiction. We could become subject to such regulations and reporting requirements in the future to the extent that any of our intrastate pipelines were to begin providing, or were found to provide, such interstate services.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other midstream natural gas companies with whom we compete.

*Natural Gas Gathering Pipeline Regulation.* Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC if the primary function of the facilities is gathering natural gas. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. We own a number of facilities that we believe meet the traditional tests FERC uses to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so we cannot provide assurance that FERC will not at some point assert that transportation on these facilities is within its jurisdiction or that such an assertion would not adversely affect our results of operations. In such a case, we would be required to file a tariff with FERC, provide a cost justification for the transportation charge and obtain certificate(s) of public convience and necessity for the FERC-regulated pipelines.

In the states in which we operate, regulation of gathering facilities and intrastate pipeline facilities generally includes various safety, environmental and, in some circumstances, open access, nondiscriminatory take requirement and complaint-based rate regulation. For example, some of our natural gas gathering facilities are subject to state ratable take and common purchaser statutes and regulations. Ratable take statutes and regulations generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes and regulations generally require gatherers to purchase gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. Although state regulation is typically less onerous than at FERC, these statutes and regulations have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services or regulated as a public utility. Our gathering operations also may be or become subject to safety and operational regulations and permitting relating to the design, siting, 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.

*Natural Gas Processing.* Our natural gas processing operations are not presently subject to FERC or state regulation. There can be no assurance that our processing operations will continue to be exempt from regulation in the future. However, although the processing facilities may not be directly related, other laws and regulations may affect the availability of natural gas for processing, such as state regulation of production rates and maximum daily production allowables from gas wells, which could impact our processing business.

*NGL Pipelines.* Several of our NGL pipelines carry NGLs across state lines; however, we do not operate these pipelines as common carrier pipelines or hold them out for service to the public because there are no third-party shippers on the pipelines and we do not expect third-party shippers to seek to use these NGL pipelines. Accordingly, we believe these pipelines would meet the qualifications for a waiver from FERC's applicable reporting and filing regulatory requirements. We cannot, however, provide assurance that FERC will not, at some point, either at the request of other entities or on its own initiative, assert that some or all of such gathering is not exempt from its filing or reporting requirements or that such an assertion would not adversely affect our results of operations. In the event FERC were to determine that these NGL pipelines would not qualify for a waiver from FERC's applicable regulatory requirements, we would likely be required to file a tariff with FERC, provide a cost justification for the transportation charge and provide service to all potential shippers without undue discrimination. We also may elect to construct one or more common carrier NGL product pipelines to transport NGL products for third-party shippers across state lines or otherwise in interstate commerce, in which event we would be required to comply with FERC requirements for such common carrier pipelines, including the filing of a tariff. Our NGL pipelines are subject to safety regulation by the Department of Transportation under 49 C.F.R. Part 195 for operators of hazardous liquid pipelines. Our NGL pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities.

*Propane Regulation.* National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the U.S. Department of Transportation ("DOT") . We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our propane operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

*Common Carrier Crude Oil Pipeline Operations.* Our Michigan Crude Pipeline is a crude oil pipeline 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.

*Pipeline Interconnections.* One or more of our fractionation plants include pipeline interconnections to interstate liquids pipelines. These pipeline interconnections are an integral part of our fractionation plant facilities and are not currently being used, nor can they be used in the future, by any third party due to their origin points at our proprietary facilities. Therefore, we believe these pipeline interconnections are ancillary facilities to our fractionation plants and are not subject to the jurisdiction of FERC. In the event that FERC were to determine that these pipeline interconnections were subject to its jurisdiction, we believe the pipelines would qualify for a waiver from FERC's applicable reporting and filing requirements. In the event that FERC were to determine that the pipeline interconnections did not qualify for such a waiver, we would likely be required to file a tariff with FERC for the pipeline interconnections, provide a cost justification for the transportation charge, and provide service to all potential shippers without undue discrimination. In such event, we may experience increased operating costs and reduced revenues.

**Environmental Matters**

*General.*

Our processing and fractionation plants, pipelines and associated facilities are subject to multiple obligations and potential liabilities under a variety of stringent and comprehensive federal, regional, state and local laws and regulations governing discharges of materials into the environment or otherwise relating to environmental protection. Such laws and regulations affect many aspects of our present and future operations, such as requiring the acquisition of permits or other approvals to conduct regulated activities that may impose burdensome conditions or potentially cause delays, restricting the manner in which we handle or dispose of our wastes, limiting or prohibiting construction or other activities in environmentally sensitive areas such as wetlands or areas inhabited by endangered species, requiring us to incur capital costs to construct, maintain and upgrade equipment and facilities, restricting the locations in which we may construct our compressor stations and other facilities or requiring the relocation of existing stations and facilities and requiring remedial actions to mitigate pollution caused by our operations or attributable to former operations. Failure to comply with these stringent and comprehensive requirements may expose us to the assessment of administrative, civil and criminal penalties, the imposition of remedial or corrective requirements and the issuance of orders enjoining or limiting some or all of our operations.

We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and the cost of continued compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial condition. We cannot assure, however, that existing environmental laws and regulations will not be reinterpreted or revised or that new environmental laws and regulations will not be adopted or become applicable to us. The trend in environmental law is to place more restrictions and limitations on activities that may be perceived to adversely affect the environment. Thus there can be no assurance as to the amount or timing of future expenditures for compliance with environmental laws and regulations, permits and permitting requirements, or remediation pursuant to such laws and regulations, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional environmental requirements that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial condition, results of operations and cash flow. We may not be able to recover some or any of these costs from insurance. Such revised or additional environmental requirements may also result in material delays in the construction or expansion of our facilities, which may materially impact our ability to meet our construction obligations with our producer customers.

*Hazardous Substance and Waste.*

To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or non-hazardous or hazardous wastes into soils, groundwater and surface water and include measures to control pollution of the environment. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include current and prior owners or operators of a site where a release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict joint and several liability for the costs of removing or remediating hazardous substances that have been released into the environment, for restoration costs and damages to natural resources and for the costs of certain health studies. Additionally, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. While we generate materials in the course of our operations that are defined as hazardous substances under CERCLA or similar state statutes, we do not believe that we have any current material liability for cleanup costs under such laws, or for third party claims or personal injury or property damage. We also may incur liability under the Resource Conservation and Recovery Act, as amended, or ("RCRA"), and comparable state statutes, which impose requirements relating to the handling and disposal of nonhazardous and hazardous wastes. Under the authority of the EPA, most states administer some or all of the provisions of the RCRA, sometimes in conjunction with their own, more stringent requirements. We are not currently required to comply with a substantial portion of the RCRA requirements relating to hazardous wastes because our operations generate minimal quantities of hazardous wastes. However, it is possible that some wastes generated by us that are currently classified as nonhazardous wastes may in the future be designated as hazardous wastes, resulting in the wastes being subject to more rigorous and costly transportation, storage, treatment and/or disposal requirements. In the course of our operations, we generate some amount of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

We currently own or lease, and have in the past owned or leased, properties that have been used over the years for natural gas gathering, processing and transportation, for NGL fractionation or for the storage, gathering and transportation of crude oil. Although waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years, a possibility exists that petroleum hydrocarbons and other nonhazardous wastes or hazardous wastes may have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination or to perform remedial operations to prevent future contamination. We do not believe that there presently exists significant surface and subsurface contamination of our properties by petroleum hydrocarbons or other wastes for which we are currently responsible.

*Ongoing Remediation and Indemnification from Third Parties.*

The prior third-party owner or operator of our Cobb, Boldman, Kenova, and Majorsville facilities, who is also the prior owner and current operator of the Kermit facility, has been, or is currently involved in, investigatory or remedial activities with respect to the real property underlying these facilities. These investigatory and remedial obligations arise out of a September 1994 "Administrative Order by Consent for Removal Actions" with EPA Regions II, III, IV and V; and with respect to the Boldman facility, an "Agreed Order" entered into by the third-party owner/operator with the Kentucky Natural Resources and Environmental Protection Cabinet in October 1994. The third party has accepted sole liability and responsibility for, and indemnifies us against, any environmental liabilities associated with the EPA Administrative Order, the Kentucky Agreed Order or any other environmental condition related to the real property prior to the effective dates of our lease or purchase of the real property. In addition, the third party has agreed to perform all the required response actions at its expense in a manner that minimizes interference with our use of the properties. We understand that to date, all actions required under these agreements have been or are being performed and, accordingly, we do not believe that the remediation obligation of these properties will have a material adverse impact on our financial condition or results of operations.

In addition, the prior third-party owner and/or operator of certain facilities on the real property on which our rail facility is being constructed near Houston, Pennsylvania has been, or is currently involved in, investigatory or remedial activities related to acid mine drainage ("AMD") with respect to the real property underlying these facilities. These investigatory and remedial obligations arise out of an arrangement entered into between the Pennsylvania Department of Environmental Protection and the third party, which has accepted liability and responsibility for, and indemnifies us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations. In addition, the third party has agreed to perform all of the required response actions at its expense in a manner that minimizes interference with our use of the property. We understand that to date, all actions required under these agreements have been or are being performed and, accordingly, we do not believe that the remediation obligation of these properties will have a material adverse impact on our financial condition or results of operations.

*Water Discharges.*

The Federal Water Pollution Control Act of 1972, as amended, also known as the ("Clean Water Act,") and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. Such discharges are prohibited, except in accord with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, rupture or leak. Any unpermitted release of pollutants, including oil, natural gas liquids or condensates, could result in administrative, civil and criminal penalties as well as significant remedial obligations. In addition, the Clean Water Act and analogous state law may also require individual permits or coverage under general permits for discharges of stormwater from certain types of facilities, but these requirements are subject to several exemptions specifically related to oil and natural gas operations and facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit. We conduct regular review of the applicable laws and regulations, and maintain discussions with the various federal, state and local agencies with regard to the application of those laws and regulations to our facilities, including the permitting process and categories of applicable permits for stormwater or other discharges, stream crossings and wetland disturbances that may be required for the construction or operation of certain of our facilities in the various states. We believe that we are in substantial compliance with the Clean Water Act and analogous state laws. However, increased construction activities, potential inadvertent releases from borings for pipelines, new permitting requirements or reinterpretations of existing requirements may be implemented that could materially increase our operating costs or materially delay the construction or expansion of our facilities.

*Hydraulic Fracturing.*

We do not conduct hydraulic fracturing operations, but we do provide gathering, processing and fractionation services with respect to natural gas and NGLs produced by our customers as a result of such operations. Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and additives under pressure into targeted subsurface 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, as amended ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuel and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, legislation has been introduced before Congress from time to time to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process but none has yet been adopted. Some states have adopted, and other states are considering adopting, laws and/or regulations that could impose more stringent permitting, disclosure and well construction requirements on natural gas drilling activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. In the event that new or more stringent federal, state or local legal restrictions relating to natural gas drilling activities or to the hydraulic fracturing process are adopted in areas where our producer customers operate, those customers could incur potentially significant added costs to comply with such hydraulic fracturing-related requirements and experience delays or curtailment in the pursuit of production or development activities, which could reduce demand for our gathering, transportation and processing services and/or our NGL fractionation services.

In addition, certain governmental reviews have been conducted or are underway that focus on potential environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 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, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, which events could delay or curtail production of natural gas, and thus reduce demand for our midstream services.

*Air Emissions.*

The Clean Air Act, as amended and comparable state laws restrict the emission of air pollutants from many sources in the United States, including processing plants and compressor stations, and also impose various monitoring and reporting requirements. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements, utilize specific equipment or technologies to control emissions, or aggregate two or more of our facilities into one application for permitting purposes. We may be required to incur capital expenditures in the future for installation of air pollution control equipment and encounter construction or operational delays while applying for, or awaiting the review, processing and issuance of new or amended permits, and we may be required to modify certain of our operations which could increase our operating costs. For example, on August 16, 2012, the EPA published final rules that establish new air emission controls for natural gas and NGL production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with production and processing activities. With regards to gathering and processing activities, these final rules, among other things, revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines. In addition, these rules establish requirements regarding emissions from: (i) wet seal and reciprocating compressors at gathering systems, boosting facilities, and onshore natural gas processing plants, effective October 15, 2012; (ii) specified pneumatic controllers at gathering systems, boosting facilities, and onshore natural gas processing plants, effective October 15, 2013; and (iii) specified storage vessels at gathering systems, boosting facilities, and onshore natural gas processing plants, effective October 15, 2013. We do not believe that these new rules will have a material adverse effect on our operations, but these rules have not yet been fully implemented by the EPA. We have been in discussions with various state agencies in the areas in which we operate with respect to their guidance, policies, rules and regulations regarding the permitting process, source determination, categories of applicable permits and control technology that may be required for the construction or operation of certain of our facilities. We believe that our operations are in substantial compliance with applicable air permitting and control technology requirements.

*Climate Change.*

As a consequence to an EPA administrative conclusion that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") into the ambient air endangers public health and welfare, the EPA has adopted regulations establishing the Prevention of Significant Deterioration ("PSD") construction and Title V operating permit programs for certain large stationary sources that are potential major sources of GHG emissions. We could become subject to these Title V and PSD permitting requirements and be required to install "best available control technology" to limit emissions of GHG's from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA also adopted rules requiring the monitoring and reporting of GHG emissions from specified GHG emission sources in the United States on an annual basis, including, among others, certain onshore and offshore oil and natural gas production and onshore oil and natural gas processing, fractionation, transmission, storage and distribution facilities, which includes certain of our operations. We are monitoring GHG emissions from our operations and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. As a result of these requirements, we may be required to incur potentially significant added costs to comply with the requirements or added capital expenditures for air pollution control equipment, or we may experience delays or possible curtailment of construction or projects in connection with applying for, obtaining or maintaining preconstruction and operating permits and we may encounter limitations on the design capacities or size of facilities.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the U.S., a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress were to undertake comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements including the imposition of a carbon tax. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, oil and natural gas produced by our exploration and production customers that, in turn, could reduce the demand for our services and thus adversely affect our cash available for distribution to our unitholders.

*Endangered Species Act and Migratory Bird Treaty Act Considerations.*

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. Endangered species that are located in various states in which we operate include, without limitation, the Indiana Bat and the American Burying Beetle. If endangered species are located in areas where we propose to construct new gathering or transportation pipelines or processing or fractionation facilities, such work could be prohibited or delayed or expensive mitigation may be required. Existing laws, regulations, policies and guidance relating to protected species may also be revised or reinterpreted in a manner that further increases our construction and mitigation costs or restricts our construction activities. Additionally, construction and operational activities could result in inadvertent impact to habitats of listed species and could result in alleged takings under the ESA, exposing the Partnership to civil or criminal enforcement actions and fines or penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we conduct operations or plan to construct pipelines or facilities could cause us to incur increased costs arising from species protection measures or could result in delays in the construction of our facilities or limitations on our customer's exploration and production activities, which could have an adverse impact on demand for our midstream operations.

The Migratory Bird Treaty Act implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without a permit. If there is the potential to adversely affect migratory birds as a result of our operations or construction activities, we may be required to obtain necessary permits to conduct those operations or construction activities, which may result in specified operating or construction restrictions on a temporary, seasonal, or permanent basis in affected areas and thus have an adverse impact on our ability to provide timely gathering, processing or fractionation services to our exploration and production customers.

**Pipeline Safety Regulations**

Our pipelines are subject to regulation by the DOT under the Natural Gas Pipeline Safety Act of 1986, as amended ("NGPSA"), with respect to natural gas, and the Hazardous Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas, oil and NGL pipeline facilities. The NGPSA and HLPSA require any entity that owns or operates pipeline facilities to comply with the regulations implemented under these acts, permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable existing NGPSA and HLPSA requirements; however, these laws are subject to further amendment, with the potential for more onerous obligations and stringent standards being imposed on pipeline owners and operators. For example, on January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), which requires increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use and leak detection system installation. The 2011 Pipeline Safety Act also directs owners and operators of interstate and intrastate gas transmission pipelines to verify their records confirming the maximum allowable pressure of pipelines in certain class locations and high consequence areas, requires promulgation of regulations for conducting tests to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas and increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial position.

Our pipelines are also subject to regulation by the DOT under the Pipeline Safety Improvement Act of 2002, which was 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 under 49 C.F.R. Part 192 that require pipeline operators to develop and implement integrity management programs for gas transmission pipelines that, in the event of a failure, could affect high consequence areas. "High consequence areas" are currently defined to include high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. Similar rules are also in place under 49 C.F.R. Part 195 for operators of hazardous liquid pipelines including lines transporting NGLs and condensates. The DOT also has adopted rules that amend the pipeline safety regulations to extend regulatory coverage to certain rural onshore hazardous liquid gathering lines and low stress pipelines, including those pipelines located in non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species or other ecological sources. While we believe that our pipeline operations are in substantial compliance with applicable requirements, due to the possibility of new or amended laws and regulations, or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the requirements will not have a material adverse effect on our results of operations or financial position. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, (i) revising the definitions of "high consequence areas" and "gathering lines"; (ii) strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed; (iii) strengthening requirements on the types of gas transmission pipeline integrity assessment methods that may be selected for use by operators; (iv) imposing gas transmission integrity management requirements on onshore gas gathering lines; (v) requiring the submission of annual, incident and safety-related conditions reports by operators of all gathering lines; and (vi) enhancing the current requirements for internal corrosion control of gathering lines.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. We believe that our operations are in substantial compliance with applicable state pipeline safety laws and regulations. However, new state pipeline safety requirements may be implemented in the future that could materially increase our operating costs.

**Employee Safety**

The workplaces associated with the processing and storage facilities and the pipelines we operate are also subject to oversight pursuant to the federal Occupational Safety and Health Act, as amended, ("OSHA"), as well as comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard-communication standard requires that we maintain information about hazardous materials used or produced in operations, and that this information be provided to employees, state and local government authorities and citizens. We believe that we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

In general, we expect industry and regulatory safety standards to become stricter over time, resulting in increased compliance expenditures. While these expenditures cannot be accurately estimated at this time, we do not expect such expenditures will have a material adverse effect on our results of operations.

**Employees**

Through our subsidiary MarkWest Hydrocarbon, we employ approximately 881 individuals to operate our facilities and provide general and administrative services. We have no employees represented by unions.

**Available Information**

Our principal executive office is located at 1515 Arapahoe Street, Tower 1, Suite 1600, Denver, Colorado 80202-2137. Our telephone number is 303-925-9200. Our common units trade on the New York Stock Exchange under the symbol "MWE." You can find more information about us at our Internet website, *www.markwest.com*. Our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and any amendments to those reports are available free of charge on or through our Internet website as soon as reasonably practicable after we electronically file or furnish such material with the Securities and Exchange Commission. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the Internet website *www.sec.gov*.

**ITEM 1A. Risk Factors**

*In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following factors when evaluating us.*

**Risks Inherent in Our Business**

***Our substantial debt and other financial obligations could impair our financial condition, results of operations and cash flow, and our ability to fulfill our debt obligations.***

We have substantial indebtedness and other financial obligations. Subject to the restrictions governing our indebtedness and other financial obligations, including the indentures governing our outstanding notes, we may incur significant additional indebtedness and other financial obligations.

Our substantial indebtedness and other financial obligations could have important consequences. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to our existing debt;
- impair our ability to obtain additional financings in the future for working capital, capital expenditures, acquisitions or general partnership and other purposes;
- have a material adverse effect on us if we fail to comply with financial and restrictive covenants in our debt agreements and an event of default occurs as a result of that failure that is not cured or waived;

- require us to dedicate a substantial portion of our cash flow to payments on our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, distributions and other general partnership requirements;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

Furthermore, these consequences could limit our ability, and the ability of our subsidiaries, to obtain future financings, make needed capital expenditures, withstand any future downturn in our business or the economy in general, conduct operations or otherwise take advantage of business opportunities that may arise.

Our obligations under our Credit Facility are secured by substantially all of our assets and guaranteed by all of our wholly-owned subsidiaries other than MarkWest Liberty Midstream and its subsidiaries, but including our operating company (please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—*Liquidity and Capital Resources*). Our Credit Facility and our indentures contain covenants requiring us to maintain specified financial ratios and satisfy other financial conditions, which may limit our ability to grant liens on our assets, make or own certain investments, enter into any swap contracts other than in the ordinary course of business, merge, consolidate or sell assets, incur indebtedness senior to our Credit Facility, make distributions on equity investments and declare or make, directly or indirectly, any distribution on our common units. Any future breach of any of these covenants or our failure to meet any of these ratios or conditions could result in a default under the terms of our Credit Facility, or our indentures, which could result in acceleration of our debt and other financial obligations. If we were unable to repay those amounts, the lenders could initiate a bankruptcy or liquidation proceeding or proceed against the collateral.

***Global economic conditions may have adverse impacts on our business and financial condition.***

Changes in economic conditions could adversely affect our financial condition and results of operations. A number of economic factors, including, but not limited to, gross domestic product, consumer interest rates, government spending sequestration, strength of U.S. currency versus other international currencies, consumer confidence and debt levels, retail trends, inflation and foreign currency exchange rates, may generally affect our business. Recessionary economic cycles, higher unemployment rates, higher fuel and other energy costs and higher tax rates may adversely affect demand for natural gas, NGLs and crude oil. Also, any tightening of the capital markets could adversely impact our ability to execute our long-term organic growth projects and meet our obligations to our producer customers and limit our ability to raise capital and, therefore, have an adverse impact on our ability to otherwise take advantage of business opportunities or react to changing economic and business conditions. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

***We may not have sufficient cash after the establishment of cash reserves and payment of our expenses to enable us to pay distributions at the current level.***

The amount of cash we can distribute on our common units depends principally on the amount of cash we generate from our operations, which may fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services and sales;
- the prices of, level of production of and demand for natural gas and NGLs;

- the relative prices of NGLs and crude oil, which impact the effectiveness of our hedging program;
- the volumes of natural gas we gather, process and transport;
- the level of our operating costs; and
- prevailing economic conditions.

In addition, the actual amount of cash available for distribution may depend on other factors, some of which are beyond our control, including:

- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- restrictions contained in our joint venture agreements;
- the level of capital expenditures we make, including capital expenditures incurred in connection with our enhancement projects;
- the cost of acquisitions, if any; and
- the amount of cash reserves established by our general partner.

Unitholders should be aware that the amount of cash we have available for distribution depends primarily on our cash flow and not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

***Our profitability and cash flows are affected by the volatility of NGL product and natural gas prices.***

We are subject to significant risks associated with frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and NGLs have been volatile and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price of natural gas for the prompt month contract in 2011 ranged from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu. In 2012, the same index ranged from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu. Also as an example, the composite of the weighted monthly average NGLs price at our Appalachian facilities based on our average NGLs composition in 2011 ranged from a high of approximately $2.18 per gallon to a low of approximately $1.51 per gallon. In 2012, the same composite ranged from a high of approximately $1.73 per gallon to a low of approximately $1.00 per gallon. The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the level of domestic oil, natural gas and NGL production;
- demand for natural gas and NGL products in localized markets;
- changes in interstate pipeline gas quality specifications;
- imports and exports of crude oil, natural gas and NGLs;
- seasonality and weather conditions;
- the condition of the U.S. economy;

- political conditions in other oil-producing and natural gas-producing countries; and
- government regulation, legislation and policies.

Our net operating margins under various types of commodity-based contracts are directly affected by changes in NGL product prices and natural gas prices and thus are more sensitive to volatility in commodity prices than our fee-based contracts. Additionally, our purchase and resale of gas in the ordinary course of business exposes us to significant risk of volatility in gas prices due to the potential difference in the time of the purchases and sales and the potential existence of a difference in the gas price associated with each transaction. Significant declines in commodity prices could have an adverse impact on cash flows from operations that could result in noncash impairments of long-lived assets, as well as other-than-temporary noncash impairments of our equity method investments.

***Relative changes in NGL product and natural gas prices may adversely impact our results due to frac spread, natural gas and NGL exposure.***

Under our keep-whole arrangements, our principal cost is delivering dry gas of an equivalent Btu content to replace Btus extracted from the gas stream in the form of NGLs or consumed as fuel during processing. The spread between the NGL product sales price and the purchase price of natural gas with an equivalent Btu content is called the "frac spread." Generally, the frac spread and, consequently, the net operating margins are positive under these contracts. In the event natural gas becomes more expensive on a Btu equivalent basis than NGL products, the cost of keeping the producer "whole" results in operating losses.

Additionally, due to the timing of purchases and sales of natural gas and NGLs, direct exposure to changes in market prices of either gas or NGLs can be created because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Direct exposure may occur naturally as a result of our production processes or we may create exposure through purchases of NGLs or natural gas. Given that we have derivative positions, adverse movement in prices to the positions we have taken may negatively impact results.

***Our commodity derivative activities may reduce our earnings, profitability and cash flows.***

Our operations expose us to fluctuations in commodity prices. We utilize derivative financial instruments related to the future price of crude oil, natural gas and certain NGLs with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. We have a policy to enter into derivative transactions related to only a portion of the volume of our expected production or fuel requirements and, as a result, we expect to continue to have some direct commodity price exposure. Our actual future production or fuel requirements 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 amount that is subject to our derivative financial instruments, we might be forced to settle 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, which could result in a substantial diminution of our liquidity. Alternatively, we may seek to amend the terms of our derivative financial instruments, including the extension of the settlement date of such instruments. Additionally, because we use derivative financial instruments relating to the future price of crude oil to mitigate our exposure to NGL price risk, the volatility of our future cash flows and net income may increase if there is a change in the pricing relationship between crude oil and NGLs. As a result of these factors, our risk management activities may not be as effective as we intend in reducing the downside volatility of our cash flows and, in certain circumstances, may actually increase the volatility of our cash flows. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect and our risk management policies and procedures are not properly followed. It is possible that 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. For further information about our risk management policies and procedures, please read Note 6 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

***We conduct risk management activities but we may not accurately predict future commodity price fluctuations and, therefore, expose us to financial risks and reduce our opportunity to benefit from price increases.***

We evaluate our exposure to commodity price risk from an overall portfolio basis. We have discretion in determining whether and how to manage the commodity price risk associated with our physical and derivative positions.

To the extent that we do not manage the commodity price risk relating to a position that is subject to commodity price risk and commodity prices move adversely, we could suffer losses. Such losses could be substantial and could adversely affect our operations and cash flows available for distribution to our unitholders. In addition, managing the commodity risk may actually reduce our opportunity to benefit from increases in the market or spot prices.

***The enactment of the Dodd-Frank Act and promulgation of regulations thereunder could have an adverse impact on our ability to manage risks associated with our business.***

Congress has adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the OTC derivatives market and entities. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was signed into law on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC"), the SEC and other regulators to promulgate rules and regulations implementing the legislation. The agencies have taken administrative action to defer the effectiveness of the Dodd-Frank Act as they continue to work on finalizing rules. The CFTC has also proposed a phased implementation in which entities such as the Partnership will have a further deferred compliance date. Among the regulations the CFTC has finalized are regulations establishing criteria for firms that must register as a "Swap Dealer" or "Major Swap Participant" as well as those eligible for the end-user exemption to mandatory clearing, and regulations establishing the definition and criteria for transactions that qualify as a Swaps. Similarly, the capital requirements for Swap Dealers which may have an indirect impact on our cost of hedging is still outstanding. Finally, the CFTC rule setting aggregate federal position limits for futures and option contracts for crude oil, natural gas, heating oil and gasoline and for swaps that are their economic equivalents was vacated by a Federal District Court and is currently on appeal to the Court of Appeals for the District of Columbia. While it is not possible at this time to predict when the CFTC and the SEC will finalize their Dodd-Frank rulemakings, the agencies have issued estimated timeframes which indicate that significant pending elements of the regulations will be addressed in the first half of 2013. The financial reform regulations may also require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with our derivative activities either through direct regulation of us or indirectly through regulation of our derivative counterparties, although the specifics of those provisions are uncertain at this time. The financial reform legislation also requires the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of 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 creditworthy 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. Any of these consequences could have a material, adverse effect on our income from operations, cash flows and quarterly distribution to common unitholders.

***A significant decrease in natural gas production in our areas of operation would reduce our ability to make distributions to our unitholders.***

Our gathering systems are connected to natural gas reserves and wells, from which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our gathering systems and the utilization rate at our processing plants, treating facilities and fractionation facilities, we must continually obtain new natural gas supplies. Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our gathering systems.

We have no control over the level of drilling activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, drilling costs per Mcf, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital. In addition, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. During 2011 and 2012, we saw decreases in the prices of natural gas, leading some producers to announce significant reductions to their drilling plans specifically in dry gas areas. If sustained over the long-term, low gas prices could lead to a material reduction in volumes in certain areas of our operations.

Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, throughput on our pipelines and the utilization rates of our facilities would decline, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions.

***We depend on third parties for the natural gas and refinery off-gas we process, and the NGLs we fractionate at our facilities, and a reduction in these quantities could reduce our revenues and cash flow.***

Although we obtain our supply of natural gas, refinery off-gas and NGLs from numerous third-party producers, a significant portion comes from a limited number of key producers/suppliers who are committed to us under processing contracts. According to these contracts or other supply arrangements, however, the producers are usually under no obligation to deliver a specific quantity of natural gas or NGLs to our facilities. If these key suppliers, or a significant number of other producers, were to decrease the supply of natural gas or NGLs to our systems and facilities for any reason, we could experience difficulty in replacing those lost volumes. Because our operating costs are primarily fixed, a reduction in the volumes of natural gas or NGLs delivered to us would result not only in a reduction of revenues, but also a decline in net income and cash flow.

***Growing our business by constructing new pipelines and processing and treating facilities subjects us to construction risks and risks that natural gas or NGL supplies may not be available upon completion of the facilities.***

One of the ways we intend to grow our business is through the construction of, or additions to our existing gathering, treating, processing, and fractionation facilities. The construction of gathering, processing, fractionation and treating facilities requires the expenditure of significant amounts of capital, which may exceed our expectations, and involves numerous regulatory, environmental, political, legal and inflationary uncertainties, and stringent, lengthy and occasionally unreasonable or impractical federal, state and local permitting, consent, or authorizations requirements, which may cause us to incur additional capital expenditures for meeting certain conditions or requirements or which may delay, interfere with or impair our construction activities. As a result, new facilities may not be constructed as scheduled or as originally designed, which may require redesign and additional equipment, relocations of facilities or rerouting of pipelines, which in turn could subject us to additional capital costs, additional expenses or penalties and may adversely affect our operations and cash flows available for distribution to unitholders. In addition, the coordination and monitoring of this diverse group of projects requires skilled and experienced labor. If we undertake these projects, we may not be able to complete them on schedule, or at all, or at the budgeted cost. In addition, certain agreements with our producer customers contain substantial financial penalties and/or give the producer the right to repurchase certain assets and terminate their contracts with us if construction deadlines are not achieved. Any such penalty or contract termination could have a material adverse effect on our income from operations, cash flows and quarterly distribution to common unitholders. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues until after completion of the project, if at all. Our ability to successfully manage these projects depends on obtaining skilled labor, project managers and engineers.

Furthermore, we may have only limited natural gas or NGL supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production or satisfy anticipated market demand in a region in which anticipated production growth or market demand does not materialize, the facilities may not operate as planned or may not be used at all. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas or NGLs to achieve our expected investment return, which could adversely affect our operations and cash flows available for distribution to our unitholders.

***The fees charged to third parties under our gathering, processing, transmission, transportation, fractionation and storage agreements may not escalate sufficiently to cover increases in costs, or the agreements may not be renewed or may be suspended in some circumstances.***

Our costs may increase at a rate greater than the fees we charge to third parties. Furthermore, third parties may not renew their contracts with us. Additionally, some third parties' obligations under their agreements with us may be permanently or temporarily reduced due to certain events, some of which are beyond our control, including force majeure events wherein the supply of either natural gas, NGLs or crude oil are curtailed or cut off. Force majeure events include (but are not limited to): revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions and mechanical or physical failures of equipment affecting our facilities or facilities of third parties. If the escalation of fees is insufficient to cover increased costs, or if third parties do not renew or extend their contracts with us, or if third parties suspend or terminate their contracts with us, our financial results would suffer.

***We are exposed to the credit risks of our key customers and derivative counterparties, and any material nonpayment or nonperformance by our key customers or derivative counterparties could reduce our ability to make distributions to our unitholders.***

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers, which risks may increase during periods of economic uncertainty. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any material nonpayment or nonperformance by our key customers or our derivative counterparties could reduce our ability to make distributions to our unitholders.

***We may not be able to retain existing customers, or acquire new customers, which would reduce our revenues and limit our future profitability.***

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other gatherers, processors, pipelines, fractionators, and the price of, and demand for, natural gas, NGLs and crude oil in the markets we serve. Our competitors include large oil, natural gas, refining and petrochemical companies, some of which have greater financial resources, more numerous or greater capacity pipelines, processing and other facilities, and greater access to natural gas and NGL supplies than we do. Additionally, our customers that gather gas through facilities that are not otherwise dedicated to us may develop their own processing and fractionation facilities in lieu of using our services. Certain of our competitors may also have advantages in competing for acquisitions, or other new business opportunities, because of their financial resources and synergies in operations.

As a consequence of the increase in competition in the industry, and the volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternative fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could affect our profitability. For more information regarding our competition, please read Item 1. Business—*Competition* of Part I of this Form 10-K.

***Transportation on certain of our pipelines may be subject to federal or state rate and service regulation, and the imposition and/or cost of compliance with such regulation could adversely affect our operations and cash flows available for distribution to our unitholders.***

Some of our natural gas, NGL and crude oil pipelines are or may in the future be subject to siting, public necessity, rate and service regulations by FERC or various state regulatory bodies, depending upon jurisdiction. FERC generally regulates the transportation of natural gas, NGLs and crude oil in interstate commerce and FERC's regulatory authority includes: facilities construction, acquisition, extension or abandonment of services or facilities (for natural gas pipelines only); rates; operations; accounts and records; and depreciation and amortization policies. FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, the costs we incur in our operations, the construction of new facilities or our ability to recover the full cost of operating our pipelines. We also own and are constructing pipelines that are carrying or are expected to carry NGLs owned by us across state lines. We currently are, and expect in the future to be, the only shipper on these pipelines and do not operate, and do not expect in the future to operate, these pipelines as a common carrier or hold them out for service to the public. We do not expect third-party entities to seek to utilize our NGL pipelines; therefore, we believe these pipelines would meet the qualifications for a waiver from FERC's applicable reporting and filing requirements. However, we cannot provide assurance that FERC will not at some point find that some or all of such transportation is not exempt from its reporting and filing requirements. Such a finding could subject us to potentially burdensome and expensive operational, reporting and other requirements. In addition, we may also elect to construct in the future NGL common carrier pipelines to carry NGLs of third parties across state lines or otherwise in interstate commerce, and in such event we would be required to comply with FERC rate, operational, reporting and other requirements which may increase our cost of operations.

Intrastate natural gas and liquids pipelines, as well as proprietary natural gas and liquids pipelines are generally not subject to regulation by FERC; in addition, the NGA specifically exempts natural gas gathering systems from FERC's jurisdiction. Yet, such operations may still be subject to regulation by various state agencies. The applicable statutes and regulations generally require that our rates and terms and conditions of service provide no more than a fair return on the aggregate value of the facilities used to render services and that we offer service to our shippers on a not unduly discriminatory basis. We cannot assure unitholders that FERC will not at some point determine that such gathering and/or intrastate and proprietary pipelines are within its jurisdiction, and regulate such services, which could limit the rates that we may charge and increase our costs of operation. FERC rate cases can involve complex and expensive proceedings. For more information regarding regulatory matters that could affect our business, please read Item 1. Business—*Regulatory Matters* as set forth in this report.

***Some of our natural gas, NGL and crude oil transportation operations are subject to FERC's rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return.***

Action by FERC could adversely affect our ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition and results of operations.

For example, one such matter relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. In May 2005, FERC adopted a policy statement ("Policy Statement"), stating that it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect actual or potential tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to the Policy Statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. This tax allowance policy was upheld by the D.C. Circuit in May 2007. Whether a pipeline's owners have actual or potential income tax liability may be reviewed by FERC on a case-by-case basis. How the Policy Statement is applied in practice to pipelines owned by publicly traded partnerships could impose limits on our ability to include a full income tax allowance in cost of service.

***If we are unable to obtain new rights-of-way or other property rights, or the cost of renewing existing rights-of-way or property rights increases, then we may be unable to fully execute our growth strategy, which may adversely affect our operations and cash flows available for distribution to unitholders.***

The construction of additions to our existing gathering assets and the expansion of our gathering, processing and fractionation assets may require us to obtain new rights-of-way or other property rights prior to constructing new plants, pipelines and other transportation facilities. We may be unable to obtain such rights-of-way or other property rights to connect new natural gas supplies to our existing gathering lines, to connect our existing or future facilities to new natural gas or natural gas liquids markets, or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or other property rights or to renew existing rights-of-way or property rights. If the cost of obtaining new or renewing existing rights-of-way or other property rights increases, it may adversely affect our operations and cash flows available for distribution to unitholders.

***We are indemnified for liabilities arising from an ongoing remediation of property on which certain of our facilities are located and our results of operation and our ability to make distributions to our unitholders could be adversely affected if an indemnifying party fails to perform its indemnification obligations.***

Columbia Gas is the previous owner of the property on which our Kenova, Boldman, Cobb, Kermit and Majorsville facilities are located, and is the previous operator of our Boldman and Cobb facilities and current operator of our Kermit facility. Columbia Gas has been or is currently involved in investigatory or remedial activities with respect to the real property underlying the Boldman, Cobb and Majorsville facilities pursuant to an "Administrative Order by Consent for Removal Actions" entered into by Columbia Gas and the U.S. Environmental Protection Agency and, in the case of the Boldman facility, an "Agreed Order" with the Kentucky Natural Resources and Environmental Protection Cabinet.

Columbia Gas has agreed to retain sole liability and responsibility for, and to indemnify us against, any environmental liabilities associated with these regulatory orders or the real property underlying these facilities to the extent such liabilities arose prior to the effective date of the agreements pursuant to which such properties were acquired or leased from Columbia Gas.

In addition, Consol Coal is the previous owner and/or operator of certain facilities on the real property on which our rail facility is constructed near Houston, Pennsylvania, and has been or is currently involved in investigatory or remedial activities related to AMD with respect to the real property underlying these facilities. Consol Coal has accepted liability and responsibility for, and has agreed to indemnify us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations.

Our results of operation and our ability to make cash distributions to our unitholders could be adversely affected if in the future either Columbia Gas or Consol Coal fails to perform under the indemnification provisions of which we are the beneficiary.

***Our business is subject to laws and regulations with respect to environmental, occupational safety and health, nuisance, zoning, land use and other regulatory matters, and the violation of, or the cost of compliance with, such laws and regulations could adversely affect our operations and cash flows available for distribution to our unitholders.***

Numerous governmental agencies enforce comprehensive and stringent federal, regional, state and local laws and regulations on a wide range of environmental, occupational safety and health, nuisance, zoning, land use, and other regulatory matters. We could be adversely affected by increased costs due to stricter pollution-control requirements or liabilities resulting from non-compliance with operating or other regulatory permits. Strict joint and several liability may be incurred without regard to fault, or the legality of the original conduct, under certain of the environmental laws for remediation of contaminated areas, including CERCLA, RCRA, and analogous state laws. Private parties, including the owners of properties located near our storage, fractionation and processing facilities or through which our pipeline systems pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. New, more stringent environmental laws, regulations and enforcement policies, and new, amended or re-interpreted permitting requirements and processes, might adversely affect our operations and activities, and existing laws, regulations and policies could be reinterpreted or modified to impose additional requirements, delays or constraints on our construction of facilities or on our operations. For example, it is possible that future amendment or re-interpretation of existing air emission laws could impose more stringent permitting or pollution control equipment requirements on us if two or more of our facilities are aggregated into one air emissions permit application, which could increase our costs. Federal, state and local agencies also could impose additional safety requirements, any of which could affect our profitability. Local governments may adopt more stringent local permitting and zoning ordinances that impose additional time, place and manner restrictions, delays or constraints on our activities to construct and operate our facilities, require the relocation of our facilities, prevent or restrict the expansion of our facilities, or increase our costs to construct and operate our facilities, including the construction of sound mitigation devices. In addition, we face the risk of accidental releases or spills associated with our operations, which could result in material costs and liabilities, including those relating to claims for damages to property, natural resources and persons, environmental remediation and restoration costs, and governmental fines and penalties. Our failure to comply with or alleged non-compliance with environmental or safety-related laws and regulations could result in administrative, civil and criminal penalties, the imposition of investigatory and remedial obligations and even injunctions that restrict or prohibit some or all of our operations. For more information regarding the environmental, safety and other regulatory matters that could affect our business, please read Item 1. Business—*Regulatory Matters*, Item 1. Business—*Environmental Matters*, and Item 1. Business—*Pipeline Safety Regulations*, each as set forth in this report.

***Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs, reduced demand for our services, and adversely affect the cash flows available for distribution to our unitholders.***

As a consequence to an EPA administrative conclusion that GHGs present an endangerment to public health and the environment, the EPA has adopted regulations establishing PSD construction and Title V operating permit requirements for GHG emissions from certain large stationary sources that are potential major sources of GHG emissions. Also, the EPA adopted rules regulating the monitoring and reporting of greenhouse gas emissions from specified large GHG emission sources in the United States on an annual basis, including, among others, certain onshore and offshore oil and natural gas production and onshore oil and natural gas processing, fractionation, transmission, storage and distribution facilities. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, but, in the absence of federal climate legislation in the United States in recent years, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. If Congress were to undertake comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. These requirements or the adoption of any new legislation or regulations that requires additional reporting, monitoring or recordkeeping of GHGs, limits emissions of GHGs from our equipment and operations, or imposes a carbon tax, could adversely affect our operations and materially restrict or delay our ability to obtain air permits for new or modified facilities, could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we process or fractionate. For more information regarding greenhouse gas emission and regulation, please read Item 1. Business—*Environmental Matters—Air and Greenhouse Gases*. Finally, for a variety of reasons, natural and/or anthropogenic, climate changes could occur which could 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 assets and operations, which in turn could adversely affect our cash available for distribution to our unitholders.

***Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in reduced volumes available for us to gather, process and fractionate.***

We do not conduct hydraulic fracturing operations, but we do provide gathering, processing and fractionation services with respect to natural gas and NGLs produced by our customers as a result of such operations. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but the EPA has asserted federal regulatory authority under the SDWA for certain hydraulic fracturing activities involving the use of diesel fuels and, due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislation has been introduced before Congress from time to time to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Also, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. Most notably, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014, and has also announced the proposed development of effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. Moreover, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult to complete natural gas wells in shale formations and increase our producers' costs of compliance. This could significantly reduce the volumes of natural gas that we gather and process and NGLs that we gather and fractionate which could adversely impact our earnings, profitability and cash flows.

***The amount of gas we process, gather and transmit, or the NGLs and crude oil we gather and transport, may be reduced if the pipelines to which we deliver the natural gas, NGLs or crude oil cannot, or will not, accept the gas, NGLs or crude oil.***

All of the natural gas we process, gather and transmit is delivered into pipelines for further delivery to end-users. If these pipelines cannot, or will not, accept delivery of the gas due to downstream constraints on the pipeline, limits on or changes in interstate pipeline gas quality specifications, we may be forced to limit or stop the flow of gas through our pipelines and processing systems. In addition, interruption of pipeline service upstream of our processing facilities would limit or stop flow through our processing and fractionation facilities. Likewise, if the pipelines into which we deliver NGLs or crude oil are interrupted, we may be limited in, or prevented from conducting, our crude oil or NGL transportation operations. Any number of factors beyond our control could cause such interruptions or constraints on pipeline service, including necessary and scheduled maintenance, or unexpected damage to the upstream or downstream pipelines or to ours or other's facilities. Because our revenues and net operating margins depend upon (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) the volume of crude oil we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

***We may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.***

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, the DOT through the PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could do the most harm. The regulations require the following of operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with this regulation, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures or repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of our gathering and transmission lines.

***Pipeline safety laws and regulations expanding integrity management programs or requiring the use of certain safety technologies could require us to use more comprehensive and stringent safety controls and subject us to increased capital and operating costs.***

On January 3, 2012, President Obama signed the 2011 Pipeline Safety Act, which, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of the pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. In addition, the PHMSA published a final rule in May 2011 expanding pipeline safety requirements including added reporting obligations and integrity management standards to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner. Also, in August 2011, the PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines, gathering lines and related facilities. The adoption of these and other laws or regulations that apply more comprehensive or stringent safety standards to gathering lines could require us to install new or modified safety controls, pursue added capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant and have a material adverse effect on its financial position or results of operations and ability to make distributions to our unitholders.

***Interruptions in operations at any of our facilities may adversely affect our operations and cash flows available for distribution to our unitholders.***

Our operations depend upon the infrastructure that we have developed, including processing and fractionation plants, storage facilities, gathering facilities, various means of transportation and marketing services. Any significant interruption at these facilities or pipelines, or in our ability to transmit natural gas or NGLs, or to transport crude oil to or from these facilities or pipelines for any reason, or to market the natural gas or NGL's, would adversely affect our operations and cash flows available for distribution to our unitholders.

Operations at our facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events at our physical plants or facilities;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption in the supply of crude oil to our crude oil pipeline, natural gas to our processing plants or gathering pipelines, or a disruption in the supply of NGLs to our NGL pipelines and fractionation facilities;
- disruption in our supply of water and other resources necessary to operate our facilities; and
- inadequate storage capacity or market access to support production volumes.

In addition, the construction and operation of certain of our facilities in our Northeast and Liberty segments may be impacted by surface or subsurface mining operations. One or more third parties may have previously engaged in, or may in the future engage in, subsurface mining operations near or under our facilities, which could cause subsidence or other damage to our facilities or adversely impact our construction activities. In such event, our operations at such facilities may be impaired or interrupted, and we may not be able to recover the costs incurred to repair our facilities from such third parties.

***Due to our lack of asset diversification, adverse developments in our gathering, processing, transportation, transmission, fractionation and storage businesses could reduce our operations and cash flows available for distribution to our unitholders.***

We rely exclusively on the revenues generated from our gathering, processing, transportation, transmission, fractionation and storage businesses. An adverse development in one of these businesses would have a significantly greater impact on our operations and cash flows available for distribution to our unitholders than if we maintained more diverse assets.

***We may not be able to successfully execute our business plan and may not be able to grow our business, which could adversely affect our operations and cash flows available for distribution to our unitholders.***

Our ability to successfully operate our business, generate sufficient cash to pay the quarterly cash distributions to our unitholders and to allow for growth, is subject to a number of risks and uncertainties. Similarly, we may not be able to successfully expand our business through acquiring or growing our assets, because of various factors, including economic and competitive factors beyond our control. If we are unable to grow our business, or execute on our business plan including increasing or maintaining distributions, the market price of the common units is likely to decline.

***Alternative financing strategies may not be successful.***

Periodically, we may consider the use of alternative financing strategies such as joint venture arrangements and the sale of non-strategic assets. Joint venture arrangements may not share the risks and rewards of ownership in proportion to the voting interests. Joint venture arrangements may require us to pay certain costs or to make certain capital investments and we may have little control over the amount or the timing of these payments and investments. We may not be able to negotiate terms that adequately reimburse us for our costs to fulfill service obligations for those joint ventures where we are the operator. In addition, our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone.

We may periodically sell assets or portions of our business. Separating the existing operations from our assets or operations of which we dispose may result in significant expense and accounting charges, disrupt our business or divert management's time and attention. We may not achieve expected cost savings from these dispositions or the proceeds from sales of assets or portions of our business may be lower than the net book value of the assets sold. We may not be relieved of all of our obligations related to the assets or businesses sold. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

***We are subject to operating and litigation risks that may not be covered by insurance.***

Our industry is subject to numerous operating hazards and risks incidental to processing, transporting, fractionating and storing natural gas and NGLs and to transporting and storing crude oil. These include:

- damage to pipelines, plants, related equipment and surrounding properties caused by floods, hurricanes and other natural disasters and acts of terrorism;
- inadvertent damage from vehicles and construction and farm equipment;
- leakage of crude oil, natural gas, NGLs and other hydrocarbons into the environment, including groundwater;
- fires and explosions; and
- other hazards and conditions, including those associated with various hazardous pollutant emissions, high-sulfur content, or sour gas, and proximity to businesses, homes, or other populated areas, that could also result in personal injury and loss of life, pollution and suspension of operations.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. Market conditions could cause certain insurance premiums and deductibles to become unavailable, or available only for reduced amounts of coverage. For example, insurance carriers now require broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our operations and cash flows available for distribution to our unitholders.

***Our business may suffer if any of our key senior executives or other key employees discontinues employment with us or if we are unable to recruit and retain highly skilled staff.***

Our future success depends to a large extent on the services of our key employees. Our business depends on our continuing ability to recruit, train and retain highly qualified employees, including accounting, field operations, finance and other key back-office and mid-office personnel. The competition for these employees is intense, and the loss of these employees could harm our business. Our equity based long-term incentive plans are a significant component of our strategy to retain key employees. Further, our ability to successfully integrate acquired companies or handle complexities related to managing joint ventures depends in part on our ability to retain key management and existing employees at the time of the acquisition.

***A shortage of skilled labor may make it difficult for us to maintain labor productivity, and competitive costs could adversely affect our operations and cash flows available for distribution to our unitholders.***

Our operations require skilled and experienced laborers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the midstream energy business has caused us to conduct certain operations without full staff, which decreases our productivity and increases our costs. This shortage of trained workers is the result of the previous generation's experienced workers reaching the age for retirement, combined with the difficulty of attracting new laborers to the midstream energy industry. Thus, this shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our products and services, which could adversely affect our operations and cash flows available for distribution to our unitholders.

***If we do not make acquisitions on economically acceptable terms, our future growth may be limited.***

Our ability to grow depends in part on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) unable to obtain financing for these acquisitions on economically acceptable terms, or (iii) outbid by competitors, then our future growth and ability to increase distributions may be limited.

***If we are unable to timely and successfully integrate our future acquisitions, our future financial performance may suffer, and we may fail to realize all of the anticipated benefits of the transaction.***

Our future growth may depend in part on our ability to integrate our future acquisitions. We cannot guarantee that we will successfully integrate any acquisitions into our existing operations, or that we will achieve the desired profitability and anticipated results from such acquisitions. Failure to achieve such planned results could adversely affect our operations and cash flows available for distribution to our unitholders.

The integration of acquisitions with our existing business involves numerous risks, including:

- operating a significantly larger combined organization and integrating additional midstream operations into our existing operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management's attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- integrating personnel from diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities including those under the same stringent environmental laws and regulations relating to releases of pollutants into the environment and environmental protection as are applicable to our existing plants, pipelines and facilities. If so, our operation of these new assets could cause us to incur increased costs to address these liabilities or to attain or maintain compliance with such requirements. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we may consider in determining the application of these funds and other resources.

***We have partial ownership interests in a number of joint venture legal entities, including Pioneer, MarkWest Utica EMG and its subsidiaries, Bright Star, Wirth and Centrahoma, which could adversely affect our ability to control certain decisions of these entities. In addition, we may be unable to control the amount of cash we receive from the operation of these entities and where we do not have control, we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.***

Our inability, or limited ability, to control certain aspects of management of joint venture legal entities that we have a partial ownership interest in may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for entities where we have a non-controlling ownership interest, such as in Centrahoma, we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund. Specifically;

- we may have limited ability to influence certain management decisions with respect to these entities and their subsidiaries, including decisions with respect to incurrence of expenses and distributions to us;
- these entities may establish reserves for working capital, capital projects, environmental matters and legal proceedings, which would otherwise reduce cash available for distribution to us;
- these entities may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and
- these entities may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

All of these things could significantly and adversely impact our ability to distribute cash to our unitholders.

***Our operations depend on the use of information technology ("IT") systems that could be the target of industrial espionage or cyber attack.***

Our operations depend on the use of sophisticated information technology systems for the gathering and processing of natural gas, the gathering, fractionation, transportation and marketing of NGLs, and the gathering and transportation of crude oil. Our systems and networks, as well as those of our customers, vendors and counterparties, may become the target of cyber attacks or information security breaches, which in turn could result in the unauthorized release and misuse of confidential or proprietary information as well as disrupt our operations or damage our facilities or those of third parties, which could have a material adverse effect on our revenues and increase our operating and capital costs, which could reduce the amount of cash otherwise available for distribution. We may be required to incur additional costs to modify or enhance our systems or in order to try to prevent or remediate any such attacks.

***Certain changes in accounting and/or financial reporting standards issued by the FASB, the SEC or other standard-setting bodies could have a material adverse impact on our financial position or results of operations.***

We are subject to the application of GAAP, which periodically is revised and/or expanded. As such, we periodically are required to adopt new or revised accounting and/or financial reporting standards issued by recognized accounting standard setters or regulators, including the FASB and the SEC. It is possible that future requirements, including the proposed adoption and implementation of, or convergence with, IFRS, could change our current application of GAAP. Changes in the application of GAAP and the costs of implementing such changes could result in a material adverse impact on our financial position or results of operations.

**Risks Related to Our Partnership Structure**

***We may issue additional common units without unitholder approval, which would dilute current unitholder ownership interests.***

The General Partner, without your approval, may cause us to issue additional common units or other equity securities of equal rank with or senior to the common units.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- the unitholders' proportionate ownership interest will decrease;
- the amount of cash available for distribution 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.

***Unitholders have less ability to influence management's decisions than holders of common stock in a corporation.***

Unlike the holders of common stock in a corporation, unitholders have more limited voting rights on matters affecting our business, and therefore a more limited ability to influence management's decisions regarding our business. Our amended and restated partnership agreement provides that the General Partner may not withdraw and may not be removed at any time for any reason whatsoever. Furthermore, if any person or group other than the General Partner and its affiliates acquires beneficial ownership of 20% or more of any class of units (without the prior approval of the Board), that person or group loses voting rights on all of its units. However, if unitholders are dissatisfied with the performance of our General Partner, they have the right to annually elect the Board.

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

Under Delaware law, unitholders could be held liable for our obligations as a general partner if a court determined that the right or the exercise of the right by unitholders as a group to approve certain transactions or amendments to the agreement of limited partnership, or to take other action under our amended and restated partnership agreement, was considered participation in the "control" of our business. Unitholders elect the members of the Board, which may be deemed to be participation in the "control" of our business. This could subject unitholders to liability as a general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

**Tax Risks Related to Owning our Common Units**

***Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to a material amount of entity-level taxation, then our cash available for distribution to unitholders would be substantially reduced.***

The anticipated after-tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our 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 our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, our treatment 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 the common units.

Our amended and restated partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts may be reduced to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our 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 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 we were subjected to a material amount of additional entity-level taxation or other fees by individual states, it would reduce our cash available for distribution to unitholders.***

Changes in current state law may subject us to additional entity-level taxation or fees imposed by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, use, property, ad valorem and other forms of taxation or permit, impact, throughput and miscellaneous other fees. Imposition of any such taxes or fees may substantially reduce the cash available for distribution to our unitholders. For example, the state of Texas has instituted an income-based tax that results in an entity level tax for us. We are required to pay a Texas franchise tax of 1.0% of our gross margin that is apportioned to Texas in the prior year. The imposition of entity level taxes on us by any other state may reduce the cash available for distribution to our unitholders.

***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 to our unitholders.***

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 the General Partner because the costs will reduce our cash available for distribution.

***A unitholder may be required to pay taxes on his share of our income even if the unitholder does not receive any cash distributions from us.***

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

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

If a unitholder sells his or her common units, they will recognize a gain or loss equal to the difference between the amount realized and his tax basis in those common units. Because distributions in excess of the unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in his or her common units, the amount, if any, of such prior excess distributions with respect to the common units the unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than his or her tax basis in those common units, even if the price the unitholder receives is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells common units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives 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 our common units by tax-exempt entities, such as employee benefit plans, individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and could be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable tax rate, and non-U.S. persons will be required to file federal tax returns and pay tax on their share of our taxable income. If a unitholder is a tax exempt entity or a non-U.S. person, the unitholder should consult a 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 actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.***

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted 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 a unitholder's sale of our common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's 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 the 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 units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

***A unitholder whose common units are the subject of a "securities loan"(e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated, for tax purposes, as a partner with respect to those common 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 consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common 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 securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from lending their common units.

***We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the Class A and Class B unitholders and our common unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.***

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our common unitholders, the Class A unitholders and Class B unitholders. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders, which may have an unfavorable effect. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code ("IRC") Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our unitholders.

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

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

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

***Our unitholders will likely be subject to state and local taxes and return filing requirements in states where the unitholders do not live as a result of investing in common units.***

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

## ITEM 1B. Unresolved Staff Comments

None.

## ITEM 2. Properties

The following tables set forth certain information relating to our gas processing facilities, fractionation facilities, natural gas gathering systems, NGL pipelines, natural gas pipeline and crude oil pipeline as of and for the year ended December 31, 2012.

***Gas Processing Facilities:***

| Facility | Location | Year of Initial Construction | Design Throughput Capacity | Year ended December 31, 2012 Natural Gas Throughput | Utilization of Design Capacity | NGL Throughput |
|---|---|---|---|---|---|---|
| | | | (Mcf/d) | (Mcf/d) | | (Gal/d) |
| **Southwest** | | | | | | |
| *East Texas:* | | | | | | |
| Carthage West processing facility | Panola County, TX | 2005 | 280,000 | 259,500 | 93% | 724,000 |
| Carthage East processing facility(1) | Panola County, TX | 2012 | 120,000 | 82,400 | 69% | 230,000 |
| *Oklahoma:* | | | | | | |
| Western Oklahoma processing facility | Custer County, OK | 2000 | 235,000 | 206,500 | 88% | 585,800 |
| *Gulf Coast:* | | | | | | |
| Javelina processing facility(2) | Corpus Christi, TX | 1989 | 142,000 | 118,400 | 83% | 943,400 |
| **Northeast** | | | | | | |
| *Appalachia:* | | | | | | |
| Kenova processing facility(3) | Wayne County, WV | 1996 | 160,000 | 110,500 | 69% | 204,600 |
| Boldman processing facility(3) | Pike County, KY | 1991 | 70,000 | 37,100 | 53% | 45,000 |
| Cobb processing facility | Kanawha County, WV | 2005 | 65,000 | 33,000 | 51% | 72,000 |
| Kermit processing facility(3)(4) | Mingo County, WV | 2001 | 32,000 | N/A | N/A | N/A |
| Langley processing facility(5) | Langley, KY | 2000 | 325,000 | 139,900 | 43% | 381,600 |
| **Liberty** | | | | | | |
| *Marcellus Shale:* | | | | | | |
| Houston processing facility | Washington County, PA | 2009 | 355,000 | 240,000 | 68% | 553,100 |
| Majorsville processing facility | Marshall County, WV | 2010 | 270,000 | 180,200 | 67% | 380,600 |
| Sherwood processing facility(6) | Doddridge County, WV | 2012 | 200,000 | 97,800 | 49% | 9,000 |
| Mobley processing facility(7) | Wetzel County, WV | 2012 | 200,000 | 120,500 | 60% | 13,300 |
| Keystone processing facility(8) | Butler County, PA | 2012 | 90,000 | 43,900 | 49% | 600 |
| **Utica** | | | | | | |
| *Utica Shale:* | | | | | | |
| Cadiz processing facility(9) | Harrison County, OH | 2012 | 60,000 | 4,200 | 7% | 500 |

(1) During the fourth quarter 2012, we completed a 120 MMcf/d expansion of our processing facilities in East Texas, bringing the total processing capacity at this facility to 400 MMcf/d.

(2) Also includes fractionation capacity of 29,000 Bbl/d.

(3) A portion of the gas processed at the Boldman plant, and all of the gas processed at the Kermit plant, is further processed at the Kenova plant to recover additional NGLs.

(4) The Kermit processing plant is operated by a third party solely to prevent liquids from condensing in the gathering and transmission pipelines upstream of our Kenova plant. We do not receive Kermit gas volume information but do receive all of the liquids produced at the Kermit facility.

(5) During the fourth quarter of 2012, we completed an additional cryogenic natural gas processing plant at the Langley processing complex with a capacity of 150 MMcf/d.

(6) During the fourth quarter of 2012, we began operations at the Sherwood processing plant. The volume reported is the average daily rate for the days of operation.

(7) During the fourth quarter of 2012, we began operations at the Mobley processing plant. The volume reported is the average daily rate for the days of operation.

(8) The Keystone processing plant was acquired May 29, 2012. The volume reported is the average daily rate for the days of operation.

(9) During the third quarter of 2012 we began operations at the Cadiz processing plant. The volume reported is the average daily rate for the days of operation.

***Fractionation Facilities:***

| Facility | Location | Year of Initial Construction | Design Throughput Capacity | Year ended December 31, 2012 NGL Throughput | Utilization of Design Capacity |
|---|---|---|---|---|---|
| | | | (Bbl/d) | (Bbl/d) | |
| **Northeast** | | | | | |
| *Appalachia:* | | | | | |
| Siloam fractionation plant | South Shore, KY | 1957 | 24,000 | 17,500 | 73% |
| **Liberty** | | | | | |
| *Marcellus Shale:* | | | | | |
| Houston . . . . . . . . . . . . . | Washington County, PA | 2009 | 60,000 | 24,900 | 42% |

Our Siloam facility has both above ground, pressurized NGL storage facilities, with usable capacity of two million gallons, and underground storage facilities, with usable capacity of ten million gallons. Product can be received by truck, pipeline or rail car and can be transported from the facility by truck, rail car or barge. There are ten automated 24-hour-a-day truck loading and unloading slots, a rail loading/unloading rack with 14 unloading slots and a river barge facility capable of loading barges with a capacity of up to 840,000 gallons.

Our Houston facility has above ground NGL storage with a usable capacity of 3.8 million gallons, 12 automated 24-hour-a-day truck loading and unloading slots, and a rail loading facility with a capacity of 200 railcars per day. We also have an additional 38 million gallons of NGL storage capacity that can be utilized by our Northeast, Utica and Liberty segments under a firm capacity agreement with a third party that expires in 2018.

### *Natural Gas Gathering Systems:*

| Facility | Location | Year of Initial Construction | Design Throughput Capacity | Year ended December 31, 2012 Natural Gas Throughput | Utilization of Design Capacity |
|---|---|---|---|---|---|
| | | | (Mcf/d) | (Mcf/d) | |
| **Southwest** | | | | | |
| *East Texas:* | | | | | |
| East Texas gathering system . . . . . | Panola County, TX | 1990 | 640,000 | 450,000 | 70% |
| *Oklahoma:* | | | | | |
| Western Oklahoma gathering system . . . . . . . . . . . . . . . . . | Wheeler County, TX and Roger Mills, Ellis, Custer, and Beckham Counties, OK | 1998 | 340,000 | 235,600 | 69% |
| Southeast Oklahoma gathering system . . . . . . . . . . . . . . . . . | Hughes, Pittsburg and Coal Counties, OK | 2006 | 550,000 | 487,900 | 89% |
| *Other Southwest:* | | | | | |
| Other Southwest gathering systems(10) . . . . . . . . . . . . . . | Various | Various | 121,500 | 24,300 | 20% |
| **Liberty** | | | | | |
| *Marcellus Shale:* | | | | | |
| Houston gathering system . . . . . . | Washington County, PA | 2008 | 525,000 | 371,900 | 71% |
| Sherwood gathering system(11) . . . | Doddridge County, WV | 2012 | 240,000 | 89,700 | 37% |
| Keystone gathering system(11) . . . | Butler County, PA | 2012 | 90,000 | 43,900 | 49% |
| **Utica** | | | | | |
| Cadiz gathering system(11) . . . . . | Harrison County, OH | 2012 | 60,000 | 5,000 | 8% |

(10) Excludes lateral pipelines where revenue is not based on throughput.

(11) We began these operations of these systems in 2012. The volume reported is the average daily rate for the days of operation.

### *NGL Pipelines:*

| Pipeline | Location | Year of Initial Construction | Design Throughput Capacity | Year ended December 31, 2012 NGL Throughput | Utilization of Design Capacity |
|---|---|---|---|---|---|
| | | | (Bbl/d) | (Bbl/d) | |
| **Northeast** | | | | | |
| *Appalachia:* | | | | | |
| Langley to Siloam(12) . . . . . | Langley, KY to South Shore, KY | 1957 | 19,000 | 13,400 | 71% |
| **Southwest** | | | | | |
| *East Texas:* | | | | | |
| East Texas liquidline . . . . . . | Panola County, TX | 2005 | 25,000 | 22,700 | 91% |
| **Liberty** | | | | | |
| *Marcellus Shale:* | | | | | |
| Majorsville to Houston . . . . | Washington County, PA | 2010 | 43,400 | 9,100 | 21% |
| Fort Beeler to Majorsville . . | Marshall County, WV to Washington County, PA | 2011 | 45,000 | 2,100 | 5% |
| Mobley to Majorsville(13) . . | Wetzel County, WV to Marshall County, WV | 2012 | 64,000 | 3,700 | 6% |

(12) NGLs transported through the Langley to Ranger and Ranger to Kenova pipelines are combined with NGLs recovered at the Kenova facility. The volume reported for the Langley to Siloam pipeline represents the combined NGL stream.

(13) The Mobley to Majorsville pipeline was placed into service during the fourth quarter of 2012. The volume reported is the average daily rate for the days of operation.

*Natural Gas Pipeline:*

| Pipeline | Location | Year of Initial Construction | Design Throughput Capacity | Year ended December 31, 2012 Natural Gas Throughput | Year ended December 31, 2012 Utilization of Design Capacity |
|---|---|---|---|---|---|
| | | | (Dth/d) | (Dth/d) | |
| **Southwest** | | | | | |
| *Oklahoma:* | | | | | |
| Arkoma Connector Pipeline(14) . | Coal County, OK to Bryan County, OK | 2009 | 638,000 | 301,200 | 47% |

(14) The Arkoma Connector Pipeline is a joint venture with Arkoma Pipeline Partners, LLC ("ArcLight"), an affiliate of ArcLight Capital Partners, LLC. One of our wholly-owned subsidiaries serves as the operator (see Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

*Crude Oil Pipeline:*

| Pipeline | Location | Year of Initial Construction | Design Throughput Capacity | Year ended December 31, 2012 NGL Throughput | Year ended December 31, 2012 Utilization of Design Capacity |
|---|---|---|---|---|---|
| | | | (Bbl/d) | (Bbl/d) | |
| **Northeast** | | | | | |
| *Michigan:* | | | | | |
| Michigan crude pipeline . . . . . . | Manistee County, MI to Crawford County, MI | 1973 | 60,000 | 9,300 | 16% |

## Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the owners of record of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where determined necessary, permits, leases, license agreements and franchise ordinances from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, as applicable. We also have obtained easements and license agreements from railroad companies to cross over or under railroad properties or rights-of-way. Many of these authorizations and grants are revocable at the election of the grantor. Many of our processing and fractionation facilities, including our Siloam and Houston fractionation plants, and certain of our pipelines and other facilities, are on land that we own in fee or are held under long-term leases.

Some of the leases, easements, rights-of-way, permits, licenses and franchise ordinances that were transferred to us required the consent of the then-current landowner to transfer these rights, which in some instances was a governmental entity. We believe that we have obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business. We also believe we have satisfactory title or other right to all of our material land assets. Title to these properties is subject to encumbrances in some cases; however, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties, or will materially interfere with their use in the operation of our business.

We have pledged substantially all of our assets and those of our wholly-owned subsidiaries, other than MarkWest Liberty Midstream and its subsidiaries, as collateral for borrowings under our Credit Facility.

**ITEM 3. Legal Proceedings**

We are subject to a variety of risks and disputes, and are a party to various legal and regulatory proceedings in the normal course of our business. We maintain insurance policies in amounts and with coverage and deductibles as we believe reasonable and prudent. However, we cannot be assured that the insurance companies will promptly honor their policy obligations or that the coverage or levels of insurance will be adequate to protect us from all material expenses related to future claims for property loss or business interruption to us, or for third-party claims of personal and property damage or that the coverages or levels of insurance we currently have will be available in the future at economical prices. While it is not possible to predict the outcome of the legal actions with certainty, management is of the opinion that appropriate provisions and accruals for potential losses associated with all legal actions have been made in the consolidated financial statements and that none of these actions, either individually or in the aggregate, will have a material adverse effect on our financial condition, liquidity or results of operation.

On February 11, 2013 MarkWest Liberty Midstream entered into a Consent Order with the West Virginia Department of Environmental Protection ("WVDEP") relating to alleged violations of West Virginia's stormwater and erosion and sediment control regulations in connection with slips and landsides encountered during the construction of MarkWest Liberty Midstream's Mobley processing complex near Mobley, West Virginia. Under the Consent Order, MarkWest Liberty Midstream agreed to pay a civil administrative penalty in the amount of $306,210 and to submit corrective action and stream restoration plans. Pursuant to WVDEP's rules and regulations, the Consent Order is subject to a thirty day public notice period, which ends on March 22, 2013.

In connection with construction activities in eastern Ohio, MarkWest Utica EMG has experienced incidents of inadvertent releases of bentonite mud during construction borings under areas primarily involving reclaimed strip coal mine lands. MarkWest Utica EMG self-reported these incidents to the Ohio Environmental Protection Agency ("OEPA") and has remediated or is working to remediate any impacts from these bentonite releases. There was no adverse impact on human health from these incidents and the impact to the receiving areas was a physical sedimentation impact, without any chemicals or additives involved. OEPA has indicated that they are considering an administrative action, although no formal proceedings have been instituted. It is not certain the amount of penalties or other administrative remedies, if any, the OEPA may seek from MarkWest Utica EMG if any such formal proceedings are commenced.

**ITEM 4. Mine Safety Disclosures**

Not applicable.

## PART II

### ITEM 5. Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units have been listed on the New York Stock Exchange ("NYSE"), under the symbol "MWE," since May 2, 2007. Our common units had been traded on the American Stock Exchange, under the symbol "MWE," from May 24, 2002 to May 2, 2007. Prior to May 24, 2002, our equity securities were not listed on any exchange or traded on any public trading market.

The following table sets forth the high and low sales prices of the common units as reported by NYSE, as well as the amount of cash distributions paid per quarter for 2012 and 2011:

| | Unit Price | | | | | |
|---|---|---|---|---|---|---|
| **Quarter Ended** | **High** | **Low** | **Distributions Per Common Unit** | **Declaration Date** | **Record Date** | **Payment Date** |
| December 31, 2012 | $55.95 | $46.03 | $0.82 | January 23, 2013 | February 6, 2013 | February 14, 2013 |
| September 30, 2012 | $55.04 | $49.01 | $0.81 | October 25, 2012 | November 7, 2012 | November 14, 2012 |
| June 30, 2012 | $60.32 | $45.36 | $0.80 | July 26, 2012 | August 6, 2012 | August 14, 2012 |
| March 31, 2012 | $61.60 | $53.51 | $0.79 | April 26, 2012 | May 7, 2012 | May 15, 2012 |
| December 31, 2011 | $56.82 | $42.18 | $0.76 | January 26, 2012 | February 6, 2012 | February 14, 2012 |
| September 30, 2011 | $50.06 | $39.00 | $0.73 | October 18, 2011 | November 7, 2011 | November 14, 2011 |
| June 30, 2011 | $51.70 | $42.80 | $0.70 | July 21, 2011 | August 1, 2011 | August 12, 2011 |
| March 31, 2011 | $48.50 | $40.80 | $0.67 | April 21, 2011 | May 2, 2011 | May 13, 2011 |
| December 31, 2010 | $43.51 | $35.70 | $0.65 | January 27, 2011 | February 7, 2011 | February 14, 2011 |

As of February 19, 2013, there were approximately 192 holders of record of our common units.

**Distributions of Available Cash**

Within 45 days after the end of each quarter, we distribute all of our "Available Cash," including the "Available Cash" of our subsidiaries, on a pro rata basis to common unitholders of record on the applicable record date. Class B unitholders do not receive cash distributions. Class A unitholders receive distributions of Available Cash (excluding the Available Cash attributable to MarkWest Hydrocarbon.) However, because all Class A unitholders are wholly-owned subsidiaries, these intercompany distributions do not impact the amount of Available Cash that can be distributed to common unitholders.

We define "Available Cash" in our amended and restated partnership agreement, and we generally mean, for each fiscal quarter:

- all cash and cash equivalents on hand at the end of the quarter;
- less the amount of cash that the General Partner determines, in its reasonable discretion, is necessary or appropriate to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to unitholders for any one or more of the next four quarters;
- plus all cash and cash equivalents on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our Credit Facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Our ability to distribute available cash is contractually restricted by the terms of our Credit Facility and our indentures. Our Credit Facility and indentures contain covenants requiring us to maintain certain financial ratios and a minimum net worth. We are prohibited from making any distribution to unitholders if such distribution would cause an event of default or otherwise violate a covenant under our credit agreement or indentures. There is no guarantee that we will pay a quarterly distribution on the common units in any quarter.

### Distributions of Cash Upon Liquidation

If we dissolve in accordance with our amended and restated partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders, which will include the holders of Class B units that convert upon liquidation, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

### Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2012, regarding our common units that may be issued upon conversion of outstanding phantom units granted under all of our existing equity compensation plans that have been approved by security holders. There are no active plans that have not been approved by security holders.

| | Number of securities to be issued upon exercise of outstanding options, warrants and rights | Weighted average exercise price of outstanding options, warrants and rights(1) | Number of securities remaining available for future issuance under equity compensation plans(2) |
|---|---|---|---|
| Equity compensation plans approved by security holders: | | | |
| 2008 Long-Term Incentive Plan . . . . . . . | 687,576 | $— | 2,059,250 |

(1) Phantom units are granted with no exercise price.

(2) In June 2012 unitholders approved a 1.2 million unit increase to common units available.

### Recent Sales of Unregistered Units

None.

### Repurchase of Equity by MarkWest Energy Partners, L.P.

None.

## ITEM 6. Selected Financial Data

The following table sets forth selected consolidated historical financial and operating data for MarkWest Energy Partners (dollars in thousands, except per unit amounts). The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation in this Form 10-K.

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2012** | **2011** | **2010** | **2009** | **2008** |
| **Statement of Operations:** | | | | | |
| Revenue: | | | | | |
| Revenue | $ 1,395,231 | $1,534,434 | $1,241,563 | $ 858,635 | $1,060,662 |
| Derivative gain (loss)(1) | 56,535 | (29,035) | (53,932) | (120,352) | 277,828 |
| Total revenue | 1,451,766 | 1,505,399 | 1,187,631 | 738,283 | 1,338,490 |
| Operating expenses: | | | | | |
| Purchased product costs | 530,328 | 682,370 | 578,627 | 408,826 | 615,902 |
| Derivative (gain) loss related to purchased product costs(1) | (13,962) | 52,960 | 27,713 | 68,883 | 22,371 |
| Facility expenses | 208,385 | 173,598 | 151,449 | 126,977 | 103,682 |
| Derivative loss (gain) related to facility expenses(1) | 1,371 | (6,480) | (1,295) | (373) | 644 |
| Selling, general and administrative expenses | 94,116 | 81,229 | 75,258 | 63,728 | 68,975 |
| Depreciation | 189,549 | 149,954 | 123,198 | 95,537 | 67,480 |
| Amortization of intangible assets | 53,320 | 43,617 | 40,833 | 40,831 | 38,483 |
| Loss on disposal of property, plant and equipment | 6,254 | 8,797 | 3,149 | 1,677 | 178 |
| Accretion of asset retirement obligations | 677 | 1,190 | 237 | 198 | 129 |
| Impairment of goodwill and long-lived assets | — | — | — | 5,855 | 36,351 |
| Total operating expenses | 1,070,038 | 1,187,235 | 999,169 | 812,139 | 954,195 |
| Income (loss) from operations | 381,728 | 318,164 | 188,462 | (73,856) | 384,295 |
| Other income (expense): | | | | | |
| Earnings (loss) from unconsolidated affiliates | 699 | (1,095) | 1,562 | 3,505 | 90 |
| Impairment of unconsolidated affiliate | — | — | — | — | (41,449) |
| Gain on sale of unconsolidated affiliate | — | — | — | 6,801 | — |
| Interest income | 419 | 422 | 1,670 | 349 | 3,769 |
| Interest expense | (120,191) | (113,631) | (103,873) | (87,419) | (64,563) |
| Amortization of deferred financing costs and discount (a component of interest expense) | (5,601) | (5,114) | (10,264) | (9,718) | (8,299) |
| Derivative gain related to interest expense(1) | — | — | 1,871 | 2,509 | — |
| Loss on redemption of debt | — | (78,996) | (46,326) | — | — |
| Miscellaneous income (expense), net(1) | 62 | 144 | 1,189 | 2,459 | (241) |
| Income (loss) before provision for income tax | 257,116 | 119,894 | 34,291 | (155,370) | 273,602 |
| Provision for income tax expense (benefit): | | | | | |
| Current | (2,366) | 17,578 | 7,655 | 8,072 | 15,032 |
| Deferred | 40,694 | (3,929) | (4,466) | (50,088) | 53,798 |
| Total provision for income tax | 38,328 | 13,649 | 3,189 | (42,016) | 68,830 |
| Net income (loss) | 218,788 | 106,245 | 31,102 | (113,354) | 204,772 |
| Net loss (income) attributable to non-controlling Interest | 1,614 | (45,550) | (30,635) | (5,314) | 3,301 |
| Net income (loss) attributable to the Partnership's unitholders | $ 220,402 | $ 60,695 | $ 467 | $ (118,668) | $ 208,073 |
| Net income (loss) attributable to the Partnership's common unitholders per common unit(2): | | | | | |
| Basic | $ 1.98 | $ 0.75 | $ (0.01) | $ (1.97) | $ 4.02 |
| Diluted | $ 1.69 | $ 0.75 | $ (0.01) | $ (1.97) | $ 4.02 |
| Cash distribution declared per common unit | $ 3.160 | $ 2.750 | $ 2.560 | $ 2.560 | $ 2.059 |

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| **Balance Sheet Data (at December 31):** | | | | | |
| Working capital | $ (82,587) | $ 4,234 | $ (43,296) | $ 13,536 | $ 51,237 |
| Property, plant and equipment, net | 5,075,628 | 2,864,307 | 2,319,024 | 1,981,644 | 1,569,525 |
| Total assets | 6,835,716 | 4,070,425 | 3,333,362 | 3,014,737 | 2,673,054 |
| Total long-term debt | 2,523,051 | 1,846,062 | 1,273,434 | 1,170,072 | 1,172,965 |
| Total equity | 3,215,591 | 1,502,067 | 1,458,566 | 1,309,553 | 1,148,155 |
| **Cash Flow Data:** | | | | | |
| Net cash flow provided by (used in): | | | | | |
| Operating activities | $ 496,713 | $ 414,698 | $ 312,328 | $ 223,101 | $ 226,995 |
| Investing activities | (2,472,352) | (776,553) | (485,936) | (461,753) | (909,265) |
| Financing activities | 2,206,522 | 411,421 | 143,306 | 333,083 | 647,896 |
| **Other Financial Data:** | | | | | |
| Maintenance capital expenditures(3) | $ 16,782 | $ 16,067 | $ 10,286 | $ 7,483 | $ 7,161 |
| Growth capital expenditures(3) | 1,934,645 | 535,214 | 448,382 | 479,140 | 568,137 |
| Total capital expenditures | $ 1,951,427 | $ 551,281 | $ 458,668 | $ 486,623 | $ 575,298 |

(1) As discussed further in Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K, volatility in any given period related to unrealized gains and losses on our derivative positions can be significant. The following table summarizes the realized and unrealized gains and losses impacting *Revenue*, *Purchased product costs*, *Facility expenses*, *Interest expense* and *Miscellaneous income (expense), net* (in thousands):

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| Realized (loss) gain—revenue | $ (6,508) | $(48,093) | $(33,560) | $ 87,289 | $(15,704) |
| Unrealized gain (loss)—revenue | 63,043 | 19,058 | (20,372) | (207,641) | 293,532 |
| Realized (loss) gain—purchased product costs | (26,493) | (27,711) | (21,909) | (53,052) | 7,368 |
| Unrealized gain (loss)—purchased product costs | 40,455 | (25,249) | (5,804) | (15,831) | (29,739) |
| Unrealized (loss) gain—facility expenses | (1,371) | 6,480 | 1,295 | 373 | (644) |
| Realized gain—interest expense | — | — | 2,380 | 2,000 | — |
| Unrealized (loss) gain—interest expense | — | — | (509) | 509 | — |
| Unrealized gain—miscellaneous income (expense), net | — | — | 190 | 336 | — |
| Total derivative gain (loss) | $ 69,126 | $(75,515) | $(78,289) | $(186,017) | $254,813 |

(2) For the calculation of Net income (loss) attributable to the Partnership's common unitholders per common unit, see Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

(3) Maintenance capital includes capital expenditures made to maintain our operating capacity and asset base. Growth capital includes expenditures made to expand the existing operating capacity, to increase the efficiency of our existing assets, and to facilitate an increase in volumes within our operations. Growth capital also includes costs associated with new well connections. Growth capital excludes expenditures for third-party acquisitions and equity investment.

*Operating Data*

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| **Southwest** | | | | | |
| East Texas gathering systems throughput (Mcf/d) | 450,000 | 423,600 | 430,300 | 454,400 | 442,900 |
| East Texas natural gas processed (Mcf/d) | 270,800 | 228,300 | 233,100 | 246,600 | 189,300 |
| East Texas NGL sales (gallons, in thousands) | 275,800 | 238,700 | 245,800 | 245,800 | 193,500 |
| Western Oklahoma gathering system throughput (Mcf/d)(1) | 235,600 | 237,900 | 191,100 | 185,600 | 193,500 |
| Western Oklahoma natural gas processed (Mcf/d) | 206,500 | 175,500 | 134,700 | 148,000 | 105,300 |
| Western Oklahoma NGL sales (gallons, in thousands) | 214,400 | 177,200 | 134,100 | 126,900 | 79,400 |
| Southeast Oklahoma gathering systems throughput (Mcf/d) | 487,900 | 511,900 | 521,400 | 416,800 | 318,700 |
| Southeast Oklahoma natural gas processed (Mcf/d)(2) | 121,800 | 103,400 | 81,600 | 39,400 | 46,300 |
| Southeast Oklahoma NGL sales (gallons, in thousands) | 163,300 | 125,100 | 102,300 | 48,400 | 31,000 |
| Arkoma Connector Pipeline throughput (Mcf/d)(3) | 305,900 | 307,300 | 375,900 | 277,300 | N/A |
| Other Southwest gathering system throughput (Mcf/d)(4) | 24,300 | 29,900 | 39,500 | 57,600 | 69,400 |
| Gulf Coast refinery off-gas processed (Mcf/d) | 118,400 | 113,300 | 118,600 | 120,200 | 122,900 |
| Gulf Coast liquids fractionated (Bbl/d) | 22,500 | 21,200 | 22,500 | 23,200 | 24,400 |
| Gulf Coast NGL sales (gallons excluding hydrogen, in thousands) | 345,300 | 325,700 | 345,500 | 356,300 | 376,000 |
| **Northeast(5)** | | | | | |
| Natural gas processed (Mcf/d) | 320,500 | 305,900 | 188,700 | 194,600 | 202,200 |
| NGLs fractionated (Bbl/d)(6) | 17,500 | 20,300 | 20,700 | 18,300 | 12,400 |
| Keep-whole sales (gallons, in thousands) | 131,600 | 113,800 | 136,700 | 145,500 | 140,800 |
| Percent-of-proceeds sales (gallons, in thousands) | 139,700 | 130,300 | 120,300 | 99,900 | 54,000 |
| Total NGL sales (gallons, in thousands)(7) | 271,300 | 244,100 | 257,000 | 245,400 | 194,800 |
| Crude oil transported for a fee (Bbl/d) | 9,300 | 10,300 | 12,800 | 12,300 | 13,300 |
| **Liberty(8)** | | | | | |
| Natural gas processed (Mcf/d) | 496,400 | 323,900 | 215,700 | 51,800 | 18,700 |
| Gathering system throughput (Mcf/d) | 425,000 | 245,700 | 142,200 | 53,500 | 18,700 |
| NGLs fractionated (Bbl/d)(9) | 24,900 | 11,800 | 4,200 | 1,100 | N/A |
| NGL sales (gallons, in thousands)(10) | 393,600 | 241,200 | 119,900 | 34,400 | N/A |
| **Utica(11)** | | | | | |
| Natural gas processed (Mcf/d) | 4,200 | N/A | N/A | N/A | N/A |
| Gathering system throughput (Mcf/d) | 5,000 | N/A | N/A | N/A | N/A |

(1) Includes natural gas gathered in Western Oklahoma and from the Granite Wash formation in the Texas Panhandle as management considers this one integrated area of operations.

(2) The natural gas processing in Southeast Oklahoma is outsourced to Centrahoma or other third-party processors.

(3) The Arkoma Connector Pipeline was placed into service in July 2009. The volume reported is the average daily rate for the days of operation.

(4) Excludes lateral pipelines where revenue is not based on throughput.

(5) Includes throughput from the Kenova, Cobb, Boldman and Langley processing plants. We acquired the Langley processing plant in February 2011. The volumes reported are the average daily rates for the days of operation.

(6) Amount includes 400 barrels per day, 3,900 barrels per day and 4,000 barrels per day fractionated on behalf of Liberty for 2012, 2011 and 2010, respectively. Beginning in the fourth quarter of 2011, Siloam no longer fractionates NGLs on behalf of Liberty due to the operation of Liberty's fractionation facility that began in September 2011 except during temporary periods of capacity constraint.

(7) Represents sales at the Siloam fractionator. The total sales exclude approximately 6,500,000 gallons, 59,200,000 gallons and 60,900,000 gallons sold by the Northeast on behalf of Liberty for 2012, 2011 and 2010, respectively. These volumes are included as part of NGLs sold at Liberty.

(8) The 2009 volumes of NGLs fractionated and sold represent the average daily rate for the period of operation. The 2008 volumes of natural gas gathered and processed represent the average daily rate for the period of operation.

(9) Amount includes all NGLs that were produced at the Liberty processing facilities and fractionated into purity products at our Liberty fractionation facility. Through August 2011, only propane was recovered at our Liberty facilities. In September 2011, Liberty's fractionation facility commenced operations and Liberty now has full fractionation capabilities.

(10) Includes sale of all purity products fractionated at the Liberty facilities and sale of all unfractionated NGLs. Also includes the sale of purity products fractionated and sold at the Siloam facilities on behalf of Liberty.

(11) Utica operations began in August 2012. The volumes reported are the average daily rate for the days of operation.

## ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis ("MD&A") contains statements that are forward-looking and should be read in conjunction with *Selected Financial Data* and our consolidated financial statements and accompanying notes included elsewhere in this Form 10-K. Statements that are not historical facts are forward-looking statements. We use words such as "could," "may," "predict," "should," "expect," "hope," "continue," "potential," "plan," "intend," "anticipate," "project," "believe," "estimate" and similar expressions to identify forward-looking statements. These statements are based on current expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. Forward-looking statements are not guarantees and actual results could differ materially from those expressed or implied in the forward-looking statements as a result of a number of factors. We do not update publicly any forward-looking statement with new information or future events. Undue reliance should not be placed on forward-looking statements as many of these factors are beyond our ability to control or predict.

### Overview

We are a master limited partnership engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the gathering and transportation of crude oil. We have a leading presence in many unconventional gas plays including the Marcellus Shale, Utica Shale, Huron/Berea Shale, Haynesville Shale, Woodford Shale and Granite Wash formation.

***Significant Financial and Other Highlights***

Significant financial and other highlights for the year ended December 31, 2012 are listed below. Refer to *Results of Operations* and *Liquidity and Capital Resources* for further details.

- Effective January 2012, we entered into a new Utica Shale midstream joint venture to develop natural gas processing and NGL fractionation, transportation and marketing infrastructure in eastern Ohio.
- In May 2012, we completed the Keystone Acquisition for a final purchase price of approximately $507.3 million. The acquisition expanded our presence in the liquids-rich Marcellus Shale to northwest Pennsylvania. Keystone's existing assets are located in Butler County, Pennsylvania and include two cryogenic gas processing plants, a gas gathering system and associated field compression. We gather and process liquids-rich gas, and in 2013, we will exchange NGLs for fractionated products under a long-term, fee-based agreement.
- During 2012 we continued our expansion across all segments completing five new processing facilities increasing our total processing capacity by over 700 MMcf/d.
- We received total net proceeds of approximately $1.6 billion from public offerings of common units throughout 2012.
- In August 2012, we received net proceeds of approximately $730 million from a public offering of $750 million in aggregate principal amount of 5.5% senior unsecured notes due in February 2023. Additionally, in January 2013, we received net proceeds of approximately $987 million from a public offering of $1 billion in aggregate principal amount of 4.5% senior unsecured notes due in July 2023. We used a portion of the January 2013 proceeds to pay off other debt.
- We increased the borrowing capacity under our Credit Facility from $900 million to $1.2 billion.
- Total segment operating income before items not allocated to segments increased approximately $34.0 million, or 6%, for the year ended December 31, 2012 compared to the same period in 2011. The increase is primarily due to our acquisition of M&R's interest in MarkWest Liberty Midstream and an over 23% increase in processed volumes, primarily due to expanding operations in the Liberty and Southwest segments which was partially offset by a decline in NGL prices.
- Realized losses from the settlement of our derivative instruments were $33.0 million for the year ended 2012 compared to $75.8 million for the same period in 2011. Changes in the correlation between the price of NGLs and price of crude oil have reduced the effectiveness of our crude oil derivative positions that are used to manage NGL price risk.

***Impact of Business Combination on Comparability of Financial Results***

In reviewing our historical results of operations, investors should consider the impact of our business combinations, which fundamentally affect the comparability of our results of operations over the periods discussed.

One business combination occurred in both 2012 and 2011. The results of operations for each business acquired are included in our financial statements from the respective acquisition dates. The Keystone Acquisition closed on May 29, 2012 for a final purchase price of approximately $507.3 million. As a result, approximately seven months of activity related to Keystone is reflected in the accompanying Consolidated Statements of Operations for the year ended December 31, 2012. The revenue and income before provision for income tax were not material for the year ended December 31, 2012. The Langley Acquisition of the processing facilities and Ranger Pipeline closed on February 1, 2011 for consideration of $230.7 million. As a result, eleven months of activity for the

Langley processing facilities and Ranger Pipeline is reflected in the accompanying Consolidated Statements of Operations for the year ended December 31, 2011. The revenue and income before provision for income tax were approximately $21.8 million and $6.8 million, respectively, for the year ended December 31, 2011.

## Results of Operations

### *Segment Reporting*

We classify our business in the following reportable segments: Southwest, Northeast, Liberty and Utica. We capture information in MD&A by geographical segment. Items below *Income (loss) from operations* in the accompanying Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any unrealized gains (losses) from derivative instruments are not allocated to individual business segments. Management does not consider these items allocable to or controllable by any individual business segment and therefore excludes these items when evaluating segment performance. The segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

### Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

The tables below present financial information, as evaluated by management, for the reported segments for the years ended December 31, 2012 and 2011. The information includes net operating margin, a non-GAAP financial measure. For a reconciliation of net operating margin to *Income (loss) from operations,* the most comparable GAAP financial measure, see *Our Contracts* discussion in Item 1. Business.

**Southwest**

| | Year ended December 31, | | | |
|---|---|---|---|---|
| | 2012 | 2011 | $ Change | % Change |
| | (in thousands) | | | |
| Segment revenue | $856,416 | $1,031,986 | $(175,570) | (17)% |
| Purchased product costs | 387,902 | 506,911 | (119,009) | (23)% |
| Net operating margin | 468,514 | 525,075 | (56,561) | (11)% |
| Facility expenses | 124,921 | 121,197 | 3,724 | 3% |
| Portion of operating income attributable to non-controlling interests | 5,790 | 5,431 | 359 | 7% |
| Operating income before items not allocated to segments | $337,803 | $ 398,447 | $ (60,644) | (15)% |

*Segment Revenue.* Segment revenue decreased primarily due to lower NGL prices and a decrease in natural gas sales volumes. The decrease was partially offset by an increase in NGL sales volumes, primarily due to the expansion of Western Oklahoma processing facilities completed at the end of the third quarter of 2011 and increases in processing and gathering fees in Oklahoma and Texas.

*Purchased Product Costs.* Purchased product costs decreased primarily due to lower NGL prices and reduction in the volume of natural gas purchased.

*Facility Expenses.* Facility expenses increased primarily due to the expansion of our processing and gathering facilities in Oklahoma.

## Northeast

| | Year ended December 31, 2012 | 2011 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Segment revenue | $225,818 | $268,884 | $(43,066) | (16)% |
| Purchased product costs | 68,402 | 91,612 | (23,210) | (25)% |
| Net operating margin | 157,416 | 177,272 | (19,856) | (11)% |
| Facility expenses | 24,106 | 27,126 | (3,020) | (11)% |
| Operating income before items not allocated to segments | $133,310 | $150,146 | $(16,836) | (11)% |

*Segment Revenue.* Segment revenue decreased due to lower NGL prices, as well as a contract change related to the Langley Acquisition in the first quarter of 2011. Subsequent to the Langley Acquisition, we continue to market the NGLs related to natural gas processed at the Langley Processing Facilities; however we are acting as an agent and therefore record revenue net of purchase product costs. Prior to the contract change, we were acting as the principal. The decrease in revenue was partially offset by increased NGL sales volumes, which was partly due to a key transmission pipeline feeding our processing plants that was damaged and had limited service capacity during 2011 but that was repaired and fully operational for 2012.

*Purchased Product Costs.* Purchased product costs decreased due to the contract change related to the Langley Acquisition discussed in the *Segment Revenue* section above. In addition, purchased product costs decreased due to lower prices for natural gas purchased to satisfy the keep-whole arrangements in the Appalachia area, which was partially offset by an increase in sales volumes.

*Facility Expenses.* Facility expenses decreased primarily due to a reduction in property taxes resulting from a favorable rate determination related to one of our facilities.

## Liberty

| | Year ended December 31, 2012 | 2011 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Segment revenue | $319,867 | $248,949 | $ 70,918 | 28% |
| Purchased product costs | 74,024 | 83,847 | (9,823) | (12)% |
| Net operating margin | 245,843 | 165,102 | 80,741 | 49% |
| Facility expenses | 65,825 | 34,913 | 30,912 | 89% |
| Portion of operating income attributable to non-controlling interests | — | 63,731 | (63,731) | (100)% |
| Operating income before items not allocated to segments | $180,018 | $ 66,458 | $113,560 | 171% |

*Segment Revenue.* Segment revenue increased due to ongoing expansion of the Liberty operations resulting in increased gathered, processed and fractionated volumes. Revenue increased $66.2 million related to gathering, processing and fractionation fees and approximately $20.0 million related to increased NGL product sales under a percent of proceeds agreement with a producer, offset by a decrease of approximately $17.1 million in sales of propane from inventory purchased from producer customers. NGLs sales increased due to higher volumes but were partially offset by lower prices.

*Purchased Product Costs.* Purchased product costs decreased due to lower NGL prices and lower NGL volumes purchased from producer customers.

*Facility Expenses.* Facility expenses increased due to costs related to the expansion of Liberty operations.

*Portion of Operating Income Attributable to Non-controlling Interests.* The portion of operating income attributable to non-controlling interests represents M&R's interest in net operating income of MarkWest Liberty Midstream. As a result of our acquisition of M&R's interest in MarkWest Liberty Midstream, no portion of its income is attributable to non-controlling interests for the year ended December 31, 2012.

## Utica

| | Year ended December 31, 2012 (in thousands) | 2011 | $ Change | % Change |
|---|---|---|---|---|
| Segment revenue | $ 571 | $— | $ 571 | N/A |
| Purchased product costs | — | — | — | N/A |
| Net operating margin | 571 | — | 571 | N/A |
| Facility expenses | 3,968 | — | 3,968 | N/A |
| Portion of operating (loss) income attributable to non-controlling interests | (1,359) | — | (1,359) | N/A |
| Operating (loss) income before items not allocated to segments | $(2,038) | $— | $(2,038) | N/A |

The results of operations for the year ended December 31, 2012 include our operations in Utica Shale areas of eastern Ohio. The first phase of operations began in third quarter 2012. The total planned cryogenic processing capacity is expected to be in operation in 2014. Facility expenses include start-up costs and other costs that cannot be capitalized.

**Reconciliation of Segment Operating Income to Consolidated Income (Loss) Before Provision for Income Tax**

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated income (loss) before provision for income tax for the years ended December 31, 2012 and 2011. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

| | Year ended December 31, | | | |
|---|---|---|---|---|
| | 2012 | 2011 | $ Change | % Change |
| | (in thousands) | | | |
| Total segment revenue | $1,402,672 | $1,549,819 | $(147,147) | (9)% |
| Derivative gain (loss) not allocated to segments | 56,535 | (29,035) | 85,570 | (295)% |
| Revenue deferral adjustment | (7,441) | (15,385) | 7,944 | (52)% |
| Total revenue | $1,451,766 | $1,505,399 | $ (53,633) | (4)% |
| Operating income before items not allocated to segments | $ 649,093 | $ 615,051 | $ 34,042 | 6% |
| Portion of operating income attributable to non-controlling interests | 4,431 | 69,162 | (64,731) | (94)% |
| Derivative gain (loss) not allocated to segments | 69,126 | (75,515) | 144,641 | (192)% |
| Revenue deferral adjustment | (7,441) | (15,385) | 7,944 | (52)% |
| Compensation expense included in facility expenses not allocated to segments | (1,022) | (1,781) | 759 | (43)% |
| Facility expenses adjustments | 11,457 | 11,419 | 38 | 0% |
| Selling, general and administrative expenses | (94,116) | (81,229) | (12,887) | 16% |
| Depreciation | (189,549) | (149,954) | (39,595) | 26% |
| Amortization of intangible assets | (53,320) | (43,617) | (9,703) | 22% |
| Loss on disposal of property, plant and equipment | (6,254) | (8,797) | 2,543 | (29)% |
| Accretion of asset retirement obligations | (677) | (1,190) | 513 | (43)% |
| Income from operations | 381,728 | 318,164 | 63,564 | 20% |
| Earnings (loss) from unconsolidated affiliates | 699 | (1,095) | 1,794 | (164)% |
| Interest income | 419 | 422 | (3) | (1)% |
| Interest expense | (120,191) | (113,631) | (6,560) | 6% |
| Amortization of deferred financing costs and discount (a component of interest expense) | (5,601) | (5,114) | (487) | 10% |
| Loss on redemption of debt | — | (78,996) | 78,996 | (100)% |
| Miscellaneous income, net | 62 | 144 | (82) | (57)% |
| Income before provision for income tax | $ 257,116 | $ 119,894 | $ 137,222 | 114% |

*Derivative Gain (Loss) Not Allocated to Segments.* Unrealized gain from the change in fair value of our derivative instruments was $102.1 million in 2012 compared to an unrealized gain of $0.3 million in 2011. Realized loss from the settlement of our derivative instruments was $33.0 million in 2012 compared to $75.8 million in 2011. The total change of $144.6 million is due mainly to volatility in commodity prices when comparing prices in 2012 with prices in 2011. Despite the decline in NGL prices in 2012 compared to 2011, we continued to experience realized losses on our derivative positions used to manage NGL price risk due to the decreased effectiveness of crude oil positions used as proxy contract for NGLs. We are not able to predict the future effectiveness of our crude oil positions in managing NGL price risk, but ineffectiveness may continue for the near term.

*Revenue Deferral Adjustment.* Revenue deferral adjustment relates primarily to certain contracts in which the cash consideration we receive for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as we expect to perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the year ended December 31, 2012, approximately $0.8 million and $6.6 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. For the year ended December 31, 2011, approximately $7.2 million and $8.2 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

*Selling, General and Administrative.* Selling, general and administrative expenses increased primarily due to higher labor, benefits, travel, office expense and professional services necessary to support the overall growth of our operations.

*Depreciation.* Depreciation increased due to additional projects completed during 2012 and 2011, as well as the Keystone Acquisition.

*Amortization of Intangible Assets.* Amortization increased due to the intangible asset acquired in the Keystone Acquisition.

*Interest Expense.* Interest expense increased primarily due to increased borrowings resulting from our senior notes offerings in order to fund our capital plan, but was partially offset by lower interest rates and increased capitalized interest due to a number of significant expansion projects under construction.

*Amortization of Deferred Financing Costs and Discount.* The increase was due to the amortization of deferred financing costs related to notes issued in the third quarter of 2012 and the fourth quarter of 2011.

*Loss on Redemption of Debt.* The decrease in loss on redemption of debt was related to the redemption of debt which occurred in the first quarter of 2011, while no such redemptions of debt occurred during 2012.

*Provision for Income Tax.* The total provision for income tax for the year ended December 31, 2012 was $38.3 million. See Note 21 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for details of the significant components of the provision.

MarkWest Hydrocarbon pays tax based on enacted and applicable corporate and state tax rates on its pro-rata share of income and deductions allocated to the Class A units by the Partnership.

The current provision for income tax was a tax benefit of $2.4 million for the year ended December 31, 2012 compared to a tax expense of $17.6 million for the year ended December 31, 2011. The decrease in the current provision was primarily due to a current year election of bonus depreciation for tax purposes. Approximately $2.7 million tax benefit is attributable to MarkWest Hydrocarbon, Inc. Of this amount, a tax benefit of $10.5 million is attributable to MarkWest Hydrocarbon's ownership of Class A units, and an expense of $7.8 million is related to the Corporation's NGL marketing activities. The remaining $0.3 million is related to taxes payable by the Partnership associated with the Texas Margin tax. We expect the current provision for income tax to increase in 2013 due to expected increases in additional income allocated to MarkWest Hydrocarbon as a result of its ownership of Class A units due to increases in earnings and additional income expected to be allocated by the Partnership in accordance with the internal revenue code.

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

The tables below present financial information, as evaluated by management, for the reported segments for the years ended December 31, 2011 and 2010. The information includes net operating margin, a non-GAAP financial measure. For a reconciliation of net operating margin to *Income (loss) from operations*, the most comparable GAAP financial measure, see *Our Contracts* discussion in Item 1. Business.

**Southwest**

| | Year ended December 31, 2011 | Year ended December 31, 2010 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Segment revenue | $1,031,986 | $750,928 | $281,058 | 37% |
| Purchased product costs | 506,911 | 308,960 | 197,951 | 64% |
| Net operating margin | 525,075 | 441,968 | 83,107 | 19% |
| Facility expenses | 121,197 | 115,109 | 6,088 | 5% |
| Portion of operating income attributable to non-controlling interests | 5,431 | 6,440 | (1,009) | (16)% |
| Operating income before items not allocated to segments | $ 398,447 | $320,419 | $ 78,028 | 24% |

*Segment Revenue.* Segment revenue increased primarily due to higher commodity prices for all areas of the segment, higher condensate revenue and an overall increase in the volume of natural gas processed and NGLs produced in Oklahoma, due in part to the expansion of the processing facilities.

*Purchased Product Costs.* Purchased product costs increased primarily due to higher commodity prices and an increase in the volume of natural gas processed and NGLs produced in Oklahoma.

*Facility Expenses.* Facility expenses increased primarily due to operating expenses of the SMR which began in March 2010 to provide additional services to our refinery customers at our Gulf Coast processing facilities.

**Northeast**

| | Year ended December 31, 2011 | Year ended December 31, 2010 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Segment revenue | $268,884 | $384,724 | $(115,840) | (30)% |
| Purchased product costs | 91,612 | 252,827 | (161,215) | (64)% |
| Net operating margin | 177,272 | 131,897 | 45,375 | 34% |
| Facility expenses | 27,126 | 19,513 | 7,613 | 39% |
| Operating income before items not allocated to segments | $150,146 | $112,384 | $ 37,762 | 34% |

*Segment Revenue.* Segment revenue decreased primarily due to a contract change related to the Langley Acquisition. Subsequent to the Langley Acquisition, we continue to market the NGLs related to natural gas processed at the Langley Processing Facilities; however we are acting as an agent and therefore record revenue net of purchase product costs. Prior to the contract change, we were acting as the principal. Segment revenue also decreased due to a decrease in volumes processed under keep-whole terms primarily due to the required repairs of a significant third-party transmission pipeline feeding our Kenova plant. The repairs of the transmission pipeline were completed in the fourth quarter of 2011, after which volumes returned to normal levels.

*Purchased Product Costs.* Purchased product costs decreased due to the contract change related to the Langley Acquisition discussed in the *Segment Revenue* section above. In addition, purchased product costs decreased as a percentage of revenue due to an increase in the spread between NGL and natural gas prices.

*Facility Expenses.* Facility expenses increased primarily due to the Langley Acquisition on February 1, 2011.

**Liberty**

| | Year ended December 31, 2011 | Year ended December 31, 2010 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Segment revenue | $248,949 | $105,911 | $143,038 | 135% |
| Purchased product costs | 83,847 | 16,840 | 67,007 | 398% |
| Net operating margin | 165,102 | 89,071 | 76,031 | 85% |
| Facility expenses | 34,913 | 24,028 | 10,885 | 45% |
| Portion of operating income attributable to non-controlling interests | 63,731 | 26,126 | 37,605 | 144% |
| Operating income before items not allocated to segments | $ 66,458 | $ 38,917 | $ 27,541 | 71% |

*Segment Revenue.* Segment revenue increased due to ongoing expansion of the Liberty operations and higher NGL prices. Segment revenue increased approximately $43.7 million related to gathering and processing fees and approximately $89.0 million related to NGL product sales.

*Purchased Product Costs.* Purchased product costs increased primarily due to the purchase and sale of propane from certain producers at market prices less a discount, which began in the second half of 2010.

*Facility Expenses.* Facility expenses increased due to costs related to the expansion of Liberty operations. The increase in costs related to expansion were partially offset by a reduction in compressor rental expense as compressors were purchased in the first quarter of 2010 and by environmental and remediation costs incurred in 2010 that did not recur in 2011.

*Portion of Operating Income Attributable to Non-controlling Interests.* Portion of operating income attributable to non-controlling interests represents M&R's interest in net operating income of MarkWest Liberty Midstream. The increase is the result of ongoing expansion of the Liberty operations, as well as M&R's interest increasing from 40% to 49% effective January 1, 2011. Due to our acquisition of M&R's interest effective December 31, 2011, going forward there will be no operating income allocated to non-controlling interest.

### Reconciliation of Segment Operating Income to Consolidated Income (Loss) Before Provision for Income Tax

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated income (loss) before provision for income tax for the years ended December 31, 2011 and 2010. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

| | Year ended December 31, | | | |
|---|---|---|---|---|
| | 2011 | 2010 | $ Change | % Change |
| | (in thousands) | | | |
| Total segment revenue | $1,549,819 | $1,241,563 | $308,256 | 25% |
| Derivative loss not allocated to segments | (29,035) | (53,932) | 24,897 | (46)% |
| Revenue deferral adjustment | (15,385) | — | (15,385) | N/A |
| Total revenue | $1,505,399 | $1,187,631 | $317,768 | 27% |
| Operating income before items not allocated to segments | $ 615,051 | $ 471,720 | $143,331 | 30% |
| Portion of operating income attributable to non-controlling interests | 69,162 | 32,566 | 36,596 | 112% |
| Derivative loss not allocated to segments | (75,515) | (80,350) | 4,835 | (6)% |
| Revenue deferral adjustment | (15,385) | — | (15,385) | N/A |
| Compensation expense included in facility expenses not allocated to segments | (1,781) | (1,890) | 109 | (6)% |
| Facility expenses adjustments | 11,419 | 9,091 | 2,328 | 26% |
| Selling, general and administrative expenses | (81,229) | (75,258) | (5,971) | 8% |
| Depreciation | (149,954) | (123,198) | (26,756) | 22% |
| Amortization of intangible assets | (43,617) | (40,833) | (2,784) | 7% |
| Loss on disposal of property, plant and equipment | (8,797) | (3,149) | (5,648) | 179% |
| Accretion of asset retirement obligations | (1,190) | (237) | (953) | 402% |
| Income from operations | 318,164 | 188,462 | 129,702 | 69% |
| (Loss) earnings from unconsolidated affiliates | (1,095) | 1,562 | (2,657) | (170)% |
| Interest income | 422 | 1,670 | (1,248) | (75)% |
| Interest expense | (113,631) | (103,873) | (9,758) | 9% |
| Amortization of deferred financing costs and discount (a component of interest expense) | (5,114) | (10,264) | 5,150 | (50)% |
| Derivative gain related to interest expense | — | 1,871 | (1,871) | (100)% |
| Loss on redemption of debt | (78,996) | (46,326) | (32,670) | 71% |
| Miscellaneous income, net | 144 | 1,189 | (1,045) | (88)% |
| Income before provision for income tax | $ 119,894 | $ 34,291 | $ 85,603 | 250% |

*Derivative Loss Not Allocated to Segments.* Unrealized gain from the change in fair value of our derivative instruments was $0.3 million in 2011 compared to an unrealized loss of $24.9 million in 2010. Realized loss from the settlement of our derivative instruments was $75.8 million in 2011 compared to $55.5 million in 2010. The total change of $4.8 million is due mainly to volatility in commodity prices when comparing prices in 2011 with prices in 2010.

*Revenue Deferral Adjustment.* Revenue deferral adjustment relates primarily to certain contracts in which the cash consideration we receive for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as we expect to perform a similar level of service for the entire term;

therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the year ended December 31, 2011, approximately $7.2 million and $8.2 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. There were no revenue deferral adjustments in 2010 or 2009. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

*Facility Expenses Adjustments.* Facility expenses adjustments consist of the reallocation of the MarkWest Pioneer field services fee and the reallocation of the interest expense related to the SMR, which is included in facility expenses for the purposes of evaluating the performance of the Southwest segment. The increase is due to a full year of interest expense related to the SMR in 2011 compared to approximately nine months of SMR interest expense in 2010.

*Selling, General and Administrative.* Selling, general and administrative expenses increased primarily due to higher labor, benefits and professional services necessary to support the overall growth of our operations.

*Depreciation.* Depreciation increased due to additional projects completed and placed into service during 2010 and 2011, as well as the Langley Acquisition.

*Loss on Disposal of Property, Plant and Equipment.* Loss relates to disposals of miscellaneous equipment, primarily in the Northeast segment.

*Interest Expense.* Interest expense increased primarily due to increased borrowings under our Credit Facility and a net increase in our borrowings resulting from our senior notes offerings and related redemptions in order to fund our capital plan. Interest expense also increased approximately $1.8 million related to payments of the liability associated with the SMR Transaction that began in March 2010.

*Amortization of Deferred Financing Costs and Discount.* Amortization of deferred financing costs and discount decreased primarily due to the write-off of the unamortized discount associated with our 6.875% senior notes due 2014 ("2014 Senior Notes"), which were redeemed in the fourth quarter of 2010. The decrease was partially offset by the amortization of deferred financing costs related to notes issued in the fourth quarter of 2010 and 2011.

*Loss on Redemption of Debt.* Loss on redemption of debt relates to the redemption of approximately $275 million of our 2016 Senior Notes and approximately $419 million of our 2018 Senior Notes. Approximately $7.6 million relates to the non-cash write-off of the unamortized discount and deferred finance costs associated with these senior notes and approximately $71.4 million relates to the payment of the related call and tender premiums. See Note 15 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details.

*Derivative Gain Related to Interest Expense.* Derivative gain related to interest expense reflects changes in the fair value of interest rate swaps which we used to manage the interest rate risk associated with the fair value of our fixed rate borrowings. The interest rate swaps effectively converted a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve a desired mix of fixed and variable rate debt. We settled all of the outstanding interest rate swaps in January 2010. See Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details.

*Provision for Income Tax.* The total provision for income tax for the year ended December 31, 2011 was $13.7 million. See Note 21 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for a discussion of the significant changes in the provision.

MarkWest Hydrocarbon pays tax based on enacted and applicable corporate and state tax rates on its pro-rata share of income and deductions allocated to the Class A units by the Partnership.

The current provision for income tax was $17.6 million for the year ended December 31, 2011. Approximately $16.0 million is attributable to MarkWest Hydrocarbon, Inc. Of this amount, $8.5 million is attributable to MarkWest Hydrocarbon's ownership of Class A units, and the remaining expense of $7.5 million is related to the Corporation's NGL marketing business. The remaining $1.6 million is related to taxes payable by the Partnership associated with the Texas Margin tax and Michigan Business Taxes.

**Liquidity and Capital Resources**

Our primary strategy is to expand our asset base through organic growth projects and acquisitions that are accretive to our cash available for distribution per common unit.

Our 2012 capital expenditures and our 2013 capital plan are summarized in the table below (in millions):

| | 2013 Full Year Plan | | Actual |
|---|---|---|---|
| | Low | High | Year ended December 31, 2012 |
| Consolidated growth capital(1) | $2,217 | $2,517 | $1,934 |
| Utica joint venture partner's estimated share of growth capital | (717) | (717) | (233) |
| Partnership share of growth capital | 1,500 | 1,800 | 1,701 |
| Acquisition(2) | — | — | 507 |
| Partnership share of growth capital and acquisitions | $1,500 | $1,800 | $2,208 |

(1) Growth capital includes expenditures made to expand the existing operating capacity, to increase the efficiency of our existing assets, and to facilitate an increase in volumes within our operations. Growth capital also includes costs associated with new well connections. Growth capital excludes expenditures for third-party acquisitions and equity investments.

(2) As discussed in Note 3 to the accompanying Consolidated Financial Statements, MarkWest Liberty Midstream and its wholly owned subsidiary acquired Keystone for cash of $509.6 million in May 2012 and has recorded a receivable for a $2.3 million working capital adjustment to the purchase price as of December 31, 2012.

Our primary sources of liquidity to meet operating expenses, pay distributions to our unitholders and fund capital expenditures are cash flows generated by our operations, our Credit Facility and access to debt and equity markets, both public and private. We may also consider the use of alternative financing strategies such as entering into additional joint venture arrangements or selling non-strategic assets.

Management believes that expenditures for our currently planned capital projects will be funded with cash flows from operations, current cash balances, contributions by our joint venture partners, our current borrowing capacity under the Credit Facility, additional long-term borrowings, proceeds from equity offerings, and possible sales of non-strategic assets. Our access to capital markets can be impacted by factors outside our control, including economic conditions; however, we believe that our strong cash flows and balance sheet, our Credit Facility and our credit rating will provide us with adequate access to funding given our expected cash needs. Any new borrowing cost would be affected by market conditions and long-term debt ratings assigned by independent rating agencies. As of February 19, 2013, our credit ratings were Ba2 with a Stable outlook by Moody's Investors Service, BB with a Stable outlook by Standard & Poor's, which both reflect upgrades during 2011, and BB with a Stable outlook by Fitch Ratings. Changes in our operating results, cash flows or financial position could impact the ratings assigned by the various rating agencies. Should our credit ratings be adjusted downward, we may incur higher costs to borrow, which could have a material impact on our financial condition and results of operations.

*Credit Facility*

On December 20, 2012 we amended our Credit Facility to increase the maximum permissible total leverage ratio from 5.25 to 1 to 5.5 to 1 for all quarters ending on or before December 31, 2013 thereby increasing the amount available for borrowing in 2013. Earlier in 2012, we amended our Credit Facility to increase the borrowing capacity to $1.2 billion and extend the maturity date by one year to September 7, 2017, providing us with the additional financial flexibility to continue to execute our growth strategy. See Note 15 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details of our Credit Facility.

As of February 19, 2013, we had no borrowings outstanding and $11.3 million of letters of credit outstanding under the Credit Facility, leaving approximately $1,188.7 million available for borrowing, of which approximately $680 million was available for borrowing based on financial covenant requirements. Additionally, the full amount of unused capacity is available for borrowing on a short term basis to provide financial flexibility within a given fiscal quarter.

*Senior Notes Offerings and Tender Offers*

In January 2013, we completed a public offering for $1 billion in aggregate principal amount of 4.5% senior unsecured 2023B Senior Notes, which were issued at par. We received net proceeds of approximately $986.9 million. A portion of the proceeds, together with cash on hand, was used to repurchase $81.1 million aggregate principal amount of 8.75% senior notes due April 2018, approximately $175 million of the outstanding principal amount of our 6.5% senior notes due August 2021 and approximately $245 million of the outstanding principal amount of our 6.25% senior notes due June 2022, with the remainder used to fund our capital expenditure program and for general partnership purposes.

During 2012, we completed a public offering for $750 million in aggregate principal amount of 5.5% senior unsecured 2023A Senior Notes, which were issued at 99.015% of par. We used a portion of the $730 million net proceeds to repay borrowings under our Credit Facility and used the remainder for general partnership purposes, including, but not limited to, funding capital expenditures and general working capital.

As of December 31, 2012, we had five series of senior notes outstanding: $81 million in aggregate principal issued in April and May 2008 and due April 2018; $500 million in aggregate principal issued in November 2010 and due November 2020; $500 million in aggregate principal issued in February and March 2011 and due August 2021; $700 million aggregate principal issued in October 2011 and due June 2022; $750 million aggregate principal issued in August 2012 and due in February 2023 (altogether the "Senior Notes"). For further discussion of the Senior Notes and the accounting impacts, see Note 15 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

*Debt Covenants*

The Credit Facility and indentures governing the Senior Notes limit the activity of the Partnership and its restricted subsidiaries. The Credit Facility and indentures place limits on the ability of the Partnership and its restricted subsidiaries to incur additional indebtedness; declare or pay dividends or distributions or redeem, repurchase or retire equity interests or subordinated indebtedness; make investments; incur liens; create any consensual limitation on the ability of the Partnership's restricted subsidiaries to pay dividends or distributions, make loans or transfer property to the Partnership; engage in transactions with the Partnership's affiliates; sell assets, including equity interests of the Partnership's subsidiaries; make any payment on or with respect to, or purchase, redeem, defease or otherwise acquire or retire for value any subordinated obligation or guarantor subordination obligation (except principal and interest at maturity); and consolidate, merge or transfer assets.

The Credit Facility limits our ability to enter into transactions with parties that require margin calls under certain derivative instruments. Under the Credit Facility, neither we nor the bank can require margin calls for outstanding derivative positions. As of February 19, 2013, all of our derivative positions are with members of the participating bank group and are not subject to margin deposit requirements. We believe this arrangement gives us additional liquidity as it allows us to enter into derivative instruments without utilizing cash for margin calls or requiring the use of letters of credit. We believe the recent Dodd-Frank legislation will not change our ability to enter into derivatives without utilizing cash for margin calls.

*Equity Offerings*

On November 19, 2012, we completed a public offering of approximately 9.8 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' option to purchase additional units. The total net proceeds, including the exercise of the underwriters' option, was approximately $437 million and were used to fund the capital expenditure program and for general partnership purposes. The proceeds partially funded the January 2013 call options on the 2021 Senior Notes and the 2022 Senior Notes discussed above in *Senior Notes Offerings and Tender Offers*. We completed three additional public offerings earlier in 2012. In total, we issued 32.2 million common units and received net proceeds of approximately $1.6 billion. See Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the accounting treatment of the common unit offerings.

*Continuous Offering Program*

In November 2012, we announced the EDA which allows us from time to time, through the Manager, as our sales agent, to offer and sell common units representing limited partner interests having an aggregate offering price of up to $600 million. Sales of such common units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by us and the Manager. We may also sell common units to the Manager as principal for its own account at a price to be agreed upon at the time of the sale. For any such sales, we will enter into a separate agreement with the Manager.

Through December 31, 2012, we sold an aggregate of 0.1 million common units under the Agreement, receiving proceeds of approximately $6 million. The proceeds from sales were used for general partnership purposes. The Manager received $0.2 million for acting as our sales agent in connection with these issuances. We plan to continue issuing common units under this plan through-out 2013.

*Utica Shale Joint Venture*

Effective January 1, 2012, we and EMG Utica, LLC ("EMG Utica") executed agreements to form the Utica Joint Venture ("Original Agreement"), operated through MarkWest Utica EMG, to develop significant natural gas processing and NGL fractionation, transportation and marketing infrastructure in Eastern Ohio beginning in 2012. See Note 4 in the Notes to the Financial Statements included in Item 8 of this Form 10-K for details of the Original Agreement. In February 2013, we and EMG Utica entered into the Amended Utica LLC Agreement for MarkWest Utica EMG which replaced the Original Agreement. Pursuant to the Amended Utica LLC Agreement, the aggregate funding commitment of EMG Utica has increased from $500 million to $950 million (the "Minimum EMG Investment"). As part of this commitment, EMG Utica is required to fund, as needed, all capital required for MarkWest Utica EMG until such time as EMG Utica has contributed aggregate capital equal to $750 million (the "Tier 1 EMG Contributions"). Following the funding of the Tier 1 EMG Contributions, we will have the one time right to elect to fund up to 60% of all capital required for MarkWest Utica EMG until such time as EMG Utica has contributed aggregate capital equal to the Minimum EMG Investment, and EMG Utica will be required to fund all capital not elected to be funded by us. Once EMG Utica has funded the Minimum EMG Investment, we will be required to fund, as needed, 100% of all capital for MarkWest Utica EMG until such time as the aggregate capital that has been contributed by us and EMG Utica equals $2 billion. After such time, and until our investment balance equals 70% of the aggregate investment balances of us and EMG (the "Second Equalization Date"), EMG Utica will have the right, but not the obligation, to fund up to 10% of each capital call for MarkWest Utica EMG, and we will be required to fund all remaining capital not elected to be funded by EMG Utica. After the Second Equalization Date, we and EMG Utica will have the right, but not the obligation, to fund our pro rata portion (based on our respective investment balances) of any additional required capital and may also fund additional capital which the other party elects not to fund.

Under the Amended Utica LLC Agreement, after EMG Utica has contributed more than $500 million to MarkWest Utica EMG, and prior to December 31, 2016, EMG Utica's investment balance will also be increased by a quarterly special allocation of income ("Preference Amount") applied to the amount of capital contributed by EMG Utica in excess of $500 million. No Preference Amount will accrue after December 31, 2016.

Under the Amended Utica LLC Agreement, we will continue to receive 60% of cash generated by MarkWest Utica EMG that is available for distribution until the earlier of December 31, 2016 and the date on which our investment balance equals 60% of the aggregate investment balances ("First Equalization Date"). After the earlier to occur of those dates, cash generated by MarkWest Utica EMG that is available for distribution will be allocated to us and EMG Utica in proportion to our respective investment balances.

If our investment balance does not equal at least 51% of the aggregate investment balances of EMG Utica and us as of December 31, 2016, then EMG Utica may require that we purchase membership interests from EMG Utica so that, following the purchase, our investment balance equals 51% of the aggregate investment balances of EMG Utica and us. The purchase price payable would equal the investment balance associated with the membership interests so acquired from EMG Utica. If EMG Utica makes this election, then we would be required to purchase the membership interests on or prior to March 1, 2017, but effective as of January 1, 2017.

In contemplation of executing the Amended Utica LLC Agreement, we and EMG Utica executed an amendment to the Original Agreement in January 2013 that obligated us to temporarily fund MarkWest Utica EMG while EMG Utica completed efforts to raise additional capital to fund its remaining $150 million capital commitment under the Original Agreement. In February 2013, we contributed approximately $76.2 million to MarkWest Utica EMG and subsequently received a distribution of $61.2 million as reimbursement for the temporary funding. The remaining $15 million will be retained by MarkWest Utica EMG and treated as a capital contribution from us under the terms of the Amended Utica LLC Agreement.

*Liquidity Risks and Uncertainties*

Our ability to pay distributions to our unitholders, to fund planned capital expenditures and to make acquisitions depends upon our future operating performance. That, in turn, may be affected by prevailing economic conditions in our industry, as well as financial, business and other factors, some of which are beyond our control.

Due to lower demand caused primarily by the mild winter at the end of 2011 and in 2012 and other economic factors, NGL prices have declined significantly in 2012 compared to 2011, which has adversely impacted our liquidity and operating results and will continue to have an adverse impact if price declines are sustained.

Additionally, we execute a risk management strategy to mitigate our exposure to downward fluctuations in commodity prices. We use derivative financial instruments relating to the future price of crude oil and direct product derivatives to mitigate our exposure to NGL price risk. During 2012, the correlation between the price of NGLs and crude oil has weakened significantly and as a result, our derivative financial instruments have not been as effective in offsetting the impact of NGL price declines. If the pricing relationship between crude oil and NGLs does not return to the historical correlation or continues to weaken, our derivative financial instruments will continue to be less effective.

*Cash Flow*

The following table summarizes cash inflows (outflows) (in thousands).

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| Net cash provided by operating activities | $ 496,713 | $ 414,698 | $ 82,015 |
| Net cash used in investing activities | (2,472,352) | (776,553) | (1,695,799) |
| Net cash provided by financing activities | 2,206,522 | 411,421 | 1,795,101 |

Net cash provided by operating activities increased primarily due to a $34.0 million increase in operating income, excluding derivative gains and losses, in our operating segments and an increase in operating cash flows resulting from changes in working capital, and a $42.8 million increase in net cash flow from the settlement of commodity derivative positions. In January 2013, $25 million of our cash that was maintained as collateral for outstanding letters of credit was released to us and is available for other purposes.

Net cash used in investing activities increased primarily due to the $506.8 million net cash spent on the Keystone Acquisition which occurred in the second quarter of 2012 and a $1.4 billion increase in capital expenditures primarily related to our expansion of Liberty and Utica operations, partially offset by the $230.7 million Langley Acquisition which occurred in the first quarter of 2011.

Net cash provided by financing activities increased primarily due to:

- $538.6 million increase in proceeds from public equity offerings;
- $176.9 million increase in net borrowings;
- $997.6 million due to acquisition of EMG's interest in MarkWest Liberty Midstream which occurred in 2011;
- $139.2 million increase in cash contributions received from our joint venture partners; and
- $61 million decrease in distributions to non-controlling interest holders due to the acquisition of the non-controlling interest in MarkWest Liberty Midstream.

These increases were partially offset by:

- $121.6 million increase in distributions to common unitholders due to additional units outstanding and growth in the per unit distribution.

**Total Contractual Cash Obligations**

A summary of our total contractual cash obligations as of December 31, 2012, is as follows (in thousands):

| | Payment Due by Period | | | | |
|---|---|---|---|---|---|
| **Type of obligation** | **Total Obligation** | **Due in 2013** | **Due in 2014 - 2015** | **Due in 2016 - 2017** | **Thereafter** |
| Long-term debt(1) | $2,523,051 | $ — | $ — | $ — | $2,523,051 |
| Interest payments on long-term debt(1)(2) | 1,450,286 | 158,347 | 316,695 | 316,695 | 658,549 |
| Operating leases and long-term storage agreement(3) | 151,586 | 18,544 | 29,819 | 27,992 | 75,231 |
| Purchase obligations(4) | 664,791 | 664,791 | — | — | — |
| Natural gas purchase obligations(5) | 272,439 | 22,362 | 51,153 | 55,381 | 143,543 |
| SMR Liability(6) | 299,677 | 17,412 | 34,824 | 34,824 | 212,617 |
| Other long-term liabilities reflected on the Consolidated Balance Sheets: | | | | | |
| Asset retirement obligation(7) | 8,548 | — | — | — | 8,548 |
| Total contractual cash obligations | $5,370,378 | $881,456 | $432,491 | $434,892 | $3,621,539 |

(1) Amounts do not include the January 2013 issuance of the 2023B Senior Notes and related redemption of the 2018 Senior Notes, 2021 Senior Notes and 2022 Senior Notes.

(2) Assumes that our outstanding borrowing at December 31, 2012 remain outstanding until their respective maturity dates and we incur interest at 4.75% on our Credit Facility, 8.75% on the 2018 Senior Notes, 6.75% on the 2020 Senior Notes, 6.5% on the 2021 Senior Notes, 6.25% on the 2022 Senior Notes, and 5.5% on the 2023A Senior Notes.

(3) Amounts relate primarily to a long-term propane storage agreement and our office and vehicle leases.

(4) Represents purchase orders and contracts related to purchase or build out of property, plant and equipment. Purchase obligations exclude current and long-term unrealized losses on derivative instruments included on the accompanying Consolidated Balance Sheets, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts are generally settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity.

(5) Natural gas purchase obligations consist primarily of a purchase agreement with a producer in the Northeast segment. The contract provides for the purchase of keep-whole volumes at a specific price and is a component of a broader regional arrangement. The contract price is designed to share a portion of the frac spread with the producer and as a result, the amounts reflected for the obligation exceed the cost of purchasing the keep-whole volumes at a market price. The contract is considered an embedded derivative (see Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for the fair value of the frac spread sharing component). We use the frac spread as of December 31, 2012 for calculating this obligation.

(6) Represents amounts due under a product supply agreement (see Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the product supply agreement).

(7) Excludes estimated accretion expense of $18.7 million. The total amount to be paid is approximately $27.2 million.

**Off-Balance Sheet Arrangements**

We do not engage in off-balance sheet financing activities.

**Effects of Inflation**

Inflation did not have a material impact on our results of operations for the years ended December 31, 2012, 2011 or 2010. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire, build, or replace property, plant and equipment. It may also increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and expect to continue to pass along all or a portion of increased costs to our customers in the form of higher fees.

**Critical Accounting Policies and Estimates**

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, 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 policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements, because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See Note 2 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information on these policies and estimates, as well as a discussion of additional accounting policies and estimates.

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Intangible Assets*<br>Intangible assets are comprised of customer contracts and relationships acquired in business combinations, recorded under the purchase method of accounting at their estimated fair values at the date of acquisition. Using relevant information and assumptions, management determines the fair value of acquired identifiable intangible assets. | The fair value of customer contracts is generally calculated using an income approach based on discounted future cash flows. The key assumptions include contract renewals, historical volumes, current and future capacity of the gathering system or processing plants, pricing volatility and the discount rate.<br><br>Amortization of intangibles with definite lives is calculated using the straight-line method over the estimated useful life of the intangible asset. We consider alternative methods of amortization when the intangibles assets are initially recorded, however we have previously determined that alternative amortization methods do not create material differences in amortization expense each year and therefore concluded straight-lining methodology to be appropriate. The estimated economic life is determined by assessing the life of the assets to which the contracts and relationships relate, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions and maintenance and renewal costs. | If the actual results differ significantly from the assumptions used to determine the fair value and economic lives of intangible assets, the carrying value of the intangible asset may be over/understated resulting in an over/understatement of amortization expense as the over/understatement of the intangible assets would create an under/overstatement of other assets (i.e. goodwill). |

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Impairment of Long-Lived Assets*<br>Management evaluates our long-lived assets, including intangibles, for impairment when certain events have taken place that indicate that the carrying value may not be recoverable from the expected undiscounted future cash flows. Qualitative and quantitative information is reviewed in order to determine if a triggering event has occurred or an impairment indicator exists. If we determine that a triggering event has occurred we would complete a full impairment analysis. If we determine that the carrying value of an asset group is not recoverable, a loss is recorded for the difference between the fair value and the carrying value. We evaluate our property, plant and equipment and intangibles on at least a segment level and at lower levels where cash flows for specific assets can be identified. | Management considers the volume of reserves dedicated to be processed by the asset and future NGL product and natural gas prices to estimate cash flows for each asset group. The amount of additional reserves developed by future drilling activity depends, in part, on expected commodity prices. Projections of reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. | As of December 31, 2012, there were no indicators of impairment for any of our asset groups.<br><br>A significant variance in any of the assumptions or factors used to estimate future cash flows could result in the impairment of an asset. For certain asset groups that comprise approximately 10% of total long-lived assets, a decrease in the estimated future cash flows used in our impairment analysis would indicate that the net book value of the asset groups may not be fully recoverable and further evaluation would be required to estimate a potential impairment. |

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Impairment of Goodwill* Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of November 30 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The first step of the evaluation is a qualitative analysis to determine if it is "more likely than not" that the carrying value of a reporting unit with goodwill exceeds its fair value. The additional quantitative steps in the goodwill impairment test are only performed if we determine that it is more likely than not that the carrying value is greater than the fair value. | Management performed a quantitative analysis and determined the fair value of our reporting units using the income and market approaches for our 2012 impairment analysis. These approaches are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors such as relevant commodity prices and production volumes. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.<br><br>For the current year qualitative analysis, we analyzed the changes in the assumptions above in light of current economic conditions to determine if it was more likely than not that impairment exists. We looked at factors that include changes in the forecasted operating income and volumes for the two reporting units with goodwill, changes in the commodity price environment, changes in our per unit market value and changes in the our peers market value, and changes in industry EBITDA multiples.<br><br>Management is also required to make certain assumptions when identifying the reporting units and determining the amount of goodwill allocated to each reporting unit. The method of allocating goodwill resulting from the acquisitions involved estimating the fair value of the reporting units and allocating the purchase price for each acquisition to each reporting unit. Goodwill is then calculated for each reporting unit as the excess of the allocated purchase price over the estimated fair value of the net assets. | As a result of the goodwill impairment testing completed in 2012, we recorded no impairment expense. The fair value of our reporting units with goodwill would have to decline by more than 30% for there to be a potential indicator of impairment. |

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Impairment of Equity Investments* We evaluate our equity method investment in Centrahoma for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of an other-than-temporary loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. | Our impairment assessment requires us to apply judgment in estimating future cash flows from Centrahoma. The primary estimates include the expected volumes to be processed by Centrahoma, the terms of the related processing agreements, and future commodity prices. We determined that there were no material events or changes in circumstances that would indicate an other-than-temporary loss in value has occurred.<br><br>Our impairment assessment requires us to apply judgment in estimating future cash flows. The primary estimates include the expected volumes to be processed by Centrahoma, the terms of the related processing agreements, and future commodity prices. | Based on the current forecasts, our ownership in Centrahoma will generate cash flows with a present value in excess of the current carrying value of the investment. Management determined that there were no material events or changes in circumstances that would indicate an other-than-temporary decline in value of our investment in Centrahoma. |
| *Accounting for Risk Management Activities and Derivative Financial Instruments* Our derivative financial instruments are recorded at fair value in the accompanying Consolidated Balance Sheets. Changes in fair value and settlements are reflected in our earnings in the accompanying Consolidated Statements of Operations as gains and losses related to revenue, purchased product costs, facility expenses and/or miscellaneous income. | When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument's fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based on inputs that are largely unobservable such as option volatilities and NGL prices that are interpolated and extrapolated due to inactive markets. These instruments are classified as Level 3 under the fair value hierarchy. All fair value measurements are appropriately adjusted for nonperformance risk. | If the assumptions used in the pricing models for our Level 2 and 3 financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains that could be material. A 10% difference in our estimated fair value of Level 2 and 3 derivatives at December 31, 2012 would have affected net income before provision for income tax by approximately $9.0 million for the year ended December 31, 2012. |

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Accounting for Significant Embedded Derivative Instruments*<br>We have a Gas Purchase Agreement with Equitable ("EQT"), in which we are required to purchase natural gas based on a complex formula designed to share some of the frac-spread with EQT, through December 31, 2022. This contract has been identified as an embedded derivative and requires a complex valuation based on significant judgment.<br><br>The agreement has a primary term that expires on December 31, 2022 and contains two successive term-extending options under which EQT can extend the purchase agreement an additional five years. Such options are part of the embedded feature and thus are required to be considered in the valuation of the embedded derivative. We are required to make a significant judgment about the probability that the options would be exercised when determining the value of the extension options. | We carry the EQT embedded derivative at fair value with changes in fair value recognized in income each period. The valuation requires significant judgment when forming the assumptions used. Third-party forward curves for certain commodity prices utilized in the valuation do not extend through the term of the arrangement. Thus, pricing is required to be extrapolated for those periods. We utilize multiple cash flow techniques to extrapolate NGL pricing. Due to the illiquidity of future markets, we do not believe one method is more indicative of fair value than the other methods. The fair value is also appropriately adjusted for nonperformance risk each period.<br><br>We evaluated various factors in order to determine the probability that the term-extending options would be exercised by EQT such as estimates of future gas reserves in the region, the competitive environment in which the contract operates, the commodity price environment, and EQT's business strategy. We have asserted that the probability that EQT will exercise their option to extend the agreement is 0% as of December 31, 2012 based on the high degree of uncertainty. | The EQT Embedded Derivative is an instrument that is not exchange-traded. The valuation of the instrument is complex and requires significant judgment. The inputs used in the valuation model require specialized knowledge, as NGL price curves do not exist for the entire term of the arrangement.<br><br>The valuation is sensitive to NGL and natural gas future price curves. Holding the natural gas curves constant, a 10% increase (decrease) in NGL price curves causes a 41% increase (decrease) in the liability as of December 31, 2012. Holding the NGL curves constant, a 10% increase (decrease) in the natural gas curves causes a 15% decrease (increase) in the liability as of December 31, 2012.<br><br>The determination of the fair value of the option to extend is based on our judgment about the probability of EQT exercising the extension. If it were determined that the probability of exercise was not 0% as of December 31, 2012, the liability would be understated. |

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Variable Interest Entities*<br>We evaluate all legal entities in which we hold an ownership or other pecuniary interest to determine if the entity is a VIE.<br><br>Our interests in a VIE are referred to as variable interests. Variable interests can be contractual, ownership or other pecuniary interests in an entity that change with changes in the fair value of the VIE's assets.<br><br>When we conclude that we hold an interest in a VIE we must determine if we are the entity's primary beneficiary. A primary beneficiary is deemed to have a controlling financial interest in a VIE. This controlling financial interest is evidenced by both (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses that could potentially be significant to the VIE or the right to receive benefits that could potentially be significant to the VIE.<br><br>We consolidate any VIE when we determine that we are the primary beneficiary. We must disclose the nature of any interests in a VIE that is not consolidated. | Significant judgment is exercised in determining that a legal entity is a VIE and in evaluating our interest in a VIE.<br><br>We use primarily qualitative analysis to determine if an entity is a VIE. We evaluate the entity's need for continuing financial support; the equity holder's lack of a controlling financial interest; and/or if an equity holder's voting interests are disproportionate to its obligation to absorb expected losses or receive residual returns.<br><br>We evaluate our interests in a VIE to determine whether we are the primary beneficiary. We use primarily qualitative analysis to determine if we are deemed to have a controlling financial interest in the VIE.<br><br>We continually monitor our interests in legal entities for changes in the design or activities of an entity and changes in our interests, including our status as the primary beneficiary to determine if the changes require us to revise our previous conclusions. | MarkWest Pioneer and MarkWest Utica EMG are VIEs and we are considered the primary beneficiary of both. We have a controlling interest in the Wirth Gathering Partnership and the Bright Star Partnership, which are less-than wholly-owned but are consolidated under the voting interest model. All of these entities are consolidated subsidiaries. Changes in the design or nature of the activities of any of these entities, or our involvement with an entity may require us to reconsider our conclusions on the entity's status as a VIE and/or our status as the primary beneficiary. Such reconsideration requires significant judgment and understanding of the organization. This could result in the deconsolidation of the affected subsidiary. The deconsolidation of a subsidiary would have a significant impact on our financial statements.<br><br>We account for our ownership interest in Centrahoma under the equity method and have determined it is not a VIE. However, changes in the design or nature of the activities of the entity may require us to reconsider our conclusions. Such reconsideration would require the identification of the variable interests in the entity and a determination on which party is the entity's primary beneficiary. If Centrahoma were considered a VIE and we were determined to be the primary beneficiary, the change could cause us to consolidate the entity. The consolidation of an entity that is currently accounted for under the equity method could have a significant impact on our financial statements. |

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Acquisitions—Purchase Price Allocation*<br>We allocate the purchase price of an acquired business to its identifiable assets and liabilities based on estimated fair values. The excess of the purchase price over the amount allocated to the assets and liabilities is recorded as goodwill.<br><br>For significant acquisitions, we engage outside appraisal firms to assist in the fair value determination of identifiable intangible assets such as customer relationships, trade names and any other significant assets or liabilities. We adjust the preliminary purchase price allocation, as necessary, after the acquisition closing date through the end of the measurement period of up to one year as we finalize valuations for the assets acquired and liabilities assumed. | Purchase price allocation methodology requires management to make assumptions and apply judgment to estimate the fair value of acquired assets and liabilities. Management estimates the fair value of assets and liabilities primarily using a market approach, income approach, or cost approach, as appropriate. Key inputs into the fair value determinations include estimates and assumptions related to future volumes, commodity prices, operating costs, replacement costs and construction costs, as well as an estimate of the expected term and profits of the related customer contract or contracts. | If estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets and liabilities significantly differed from assumptions made, the allocation of purchase price between goodwill, intangibles and property plant and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangibles or goodwill are not achieved, impairments could arise. |

**Recent Accounting Pronouncements**

See Note 2—*Recent Accounting Pronouncements* of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for information regarding recent accounting pronouncements.

## ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity price changes and, to a lesser extent, interest rate changes and nonperformance by our customers and counterparties.

*Commodity Price Risk*

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty, availability of natural gas and NGL transportation, NGL fractionation capacity and a variety of additional factors that are beyond our control. Our profitability is directly affected by prevailing commodity prices primarily as a result of processing or conditioning at our or third-party processing plants, purchasing and selling, or gathering and transporting, volumes of natural gas at index-related prices and the cost of third-party transportation and fractionation services. To the extent that commodity prices influence the level of drilling activity, such prices also affect profitability. To protect ourselves financially against adverse price movements and to maintain more stable and predictable earnings so that we can meet our cash distribution objectives, debt service and capital expenditures, we execute a strategy governed by the risk management policy approved by the Board. We have a committee comprised of senior management that oversees risk management activities, continually monitors the risk management program and adjusts our strategy as conditions warrant. We enter into certain derivative contracts to reduce the risks associated with unfavorable changes in the prices of natural gas, NGLs and crude oil. Derivative contracts utilized are swaps, options and fixed price forward contracts traded on the OTC market. The risk management policy does not allow speculative derivative contracts.

To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have entered into derivative financial instruments relating to the future price of NGLs and crude oil. We manage our NGL price risk using crude oil derivatives and direct NGL product derivatives. Historically there has been a strong relationship between changes in NGL and crude oil prices. The pricing relationship between NGLs and crude oil may vary in certain periods because crude oil pricing is generally based on worldwide demand and the level of production of major crude oil exporting countries while NGL prices are correlated to North America supply and petrochemical demand. In periods where NGL prices and crude oil prices are not consistent with the historical relationship, we incur increased risk and additional gains or losses. We enter into NGL derivative contracts when adequate market liquidity exists. We expect our use of direct NGL product derivatives to increase due to the weakening in NGL to crude oil correlations.

To mitigate our cash flow exposure to fluctuations in the price of natural gas, we primarily utilize derivative financial instruments relating to the future price of natural gas and take into account the partial offset of our long and short gas positions resulting from normal operating activities.

As a result of our current derivative positions, we have mitigated a portion of our expected commodity price risk through the fourth quarter of 2014. We would be exposed to additional commodity risk in certain situations such as if producers under deliver or over deliver product or when processing facilities are operated in different recovery modes. In the event we have derivative positions in excess of the product delivered or expected to be delivered, the excess derivative positions may be terminated.

We enter into derivative contracts with financial institutions that are participating members of our Credit Facility as collateral is not posted by us due to the collateral position of the participating members in substantially all of our wholly-owned assets other than MarkWest Liberty Midstream. A separate agreement with certain bank group members allows MarkWest Liberty Midstream to enter into derivative positions without posting cash collateral. All of our financial derivative positions are currently with participating bank group members. Management conducts a standard credit review on counterparties. For all participating bank group members, collateral requirements do not exist when a derivative contract favors us. We use standardized agreements that allow for offset of positive and negative exposures (master netting arrangements).

*Outstanding Derivative Contracts*

The following tables provide information on the volume of our derivative activity for positions related to long liquids and keep-whole price risk at December 31, 2012, including the weighted-average prices ("WAVG"):

| WTI Crude Collars | Volumes (Bbl/d) | WAVG Floor (Per Bbl) | WAVG Cap (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|---|
| 2013 | 3,714 | 88.08 | 107.45 | 3,660 |
| 2014 | 1,418 | 90.36 | 108.73 | 2,683 |

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 2,263 | 94.53 | 1,051 |
| 2014 | 573 | 93.17 | 153 |

| Natural Gas Swaps | Volumes (MMBtu/d) | WAVG Price (Per MMBtu) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 1,453 | 4.66 | (693) |

| IsoButane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 22,963 | $1.68 | $(488) |

| Normal Butane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 29,344 | $1.56 | $(416) |

| Natural Gasoline Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 19,144 | $2.02 | (617) |

The following tables provide information on the volume of our taxable subsidiary's commodity derivative activity for positions related to keep-whole price risk at December 31, 2012, including the WAVG:

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 761 | 96.44 | 952 |

| Natural Gas Swaps | Volumes (MMBtu/d) | WAVG Price (Per MMBtu) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 9,793 | 5.34 | (6,422) |
| 2014 | 4,249 | 5.69 | (2,571) |

| Propane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 (Jan - Mar, Oct - Dec) | 36,885 | 1.29 | 2,239 |
| 2014 (Jan - Mar, Oct - Dec) | 87,837 | 1.25 | 3,940 |

| IsoButane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 8,819 | 1.68 | (156) |
| 2014 | 3,885 | 1.67 | (65) |

| Normal Butane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 24,217 | 1.54 | (401) |
| 2014 | 10,711 | 1.61 | 192 |

| Natural Gasoline Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 | 16,285 | 2.09 | 44 |
| 2014 | 7,106 | 2.32 | 829 |

| Propane Fixed Physical | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 (Jan - Mar) | 5,889 | 1.03 | 58 |

The following table provides information on the volume of MarkWest Liberty Midstream's commodity derivative activity positions related to long liquids price risk at December 31, 2012, including the WAVG:

| WTI Crude Collars | Volumes (Bbl/d) | WAVG Floor (Per Bbl) | WAVG Cap (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|---|
| 2013 | 1,062 | 89.33 | 106.78 | 1,115 |

| Propane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) | Fair Value (in thousands) |
|---|---|---|---|
| 2013 (Jan - Mar) | 30,897 | $0.86 | $(167) |

The following table provides information on the derivative positions related to long liquids and keep-whole price risk that we have entered into subsequent to December 31, 2012, including the WAVG:

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) |
|---|---|---|
| 2014 | 408 | $91.83 |

| IsoButane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2014 | 6,221 | $1.64 |

| Normal Butane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2014 | 8,141 | $1.56 |

The following tables provide information on the derivative positions of MarkWest Liberty Midstream related to long liquids price risk that we have entered into subsequent to December 31, 2012, including the WAVG:

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) |
|---|---|---|
| 2014 | 358 | $91.85 |

| IsoButane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2014 | 3,565 | $1.63 |

| Normal Butane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2014 | 8,440 | $1.50 |

We have a commodity contract with a producer in the Appalachia region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. This contract is accounted for as an embedded derivative and is recorded at fair value. The changes in fair value of this commodity contract are based on the difference between the contractual and index pricing and are recorded in earnings through *Derivative loss related to purchased product costs*. In February 2011, we executed agreements with the producer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022. As of December 31, 2012, the estimated fair value of this contract was a liability of $93.6 million and the recorded value was a liability of $40.1 million. The recorded liability does not include the inception fair value of the commodity contract related to the extended period from April 1, 2015 to December 31, 2022. In accordance with GAAP for non-option embedded derivatives, the fair value of this extended portion of the commodity contract at its inception of February 1, 2011 is deemed to be allocable to the host processing contract and, therefore, not recorded as a derivative liability. See the following table for a reconciliation of the liability recorded for the embedded derivative as of December 31, 2012 (in thousands):

| | |
|---|---|
| Fair value of commodity contract | $ 93,610 |
| Inception value for period from April 1, 2015 to December 31, 2022 | (53,507) |
| Derivative liability as of December 31, 2012 | $ 40,103 |

We have a commodity contract that gives us an option to fix a component of the utilities cost to an index price on electricity at one of our plant locations through the fourth quarter of 2014. The changes in the fair value of the derivative component of this contract are recognized as *Derivative (gain) loss related to facility expenses*. As of December 31, 2012, the estimated fair value of this contract was an asset of $6.1 million.

*Interest Rate Risk*

Our primary interest rate risk exposure results from our Credit Facility which has a borrowing capacity of $1.2 billion. As of February 19, 2013, we have no borrowings outstanding on our Credit Facility. The debt related to this agreement bears interest at variable rates that are tied to either the U.S. prime rate or LIBOR at the time of borrowing.

We may make use of interest rate swap agreements in the future to adjust the ratio of fixed and floating rates in our debt portfolio, however we have no interest rate swaps outstanding as of December 31, 2012. Our debt portfolio as of December 31, 2012 is shown in the following table.

| Long-Term Debt | Interest Rate | Lending Limit | Due Date | Outstanding at December 31, 2012 |
|---|---|---|---|---|
| Credit Facility | Variable | $ 1.2 billion | September 2017 | $ — |
| 2018 Senior Notes | Fixed | $ 81 million | April 2018 | $ 81 million |
| 2020 Senior Notes | Fixed | $500 million | November 2020 | $500 million |
| 2021 Senior Notes | Fixed | $500 million | August 2021 | $500 million |
| 2022 Senior Notes | Fixed | $700 million | June 2022 | $700 million |
| 2023A Senior Notes | Fixed | $750 million | February 2023 | $750 million |

In January 2013, we completed a public offering for $1 billion in aggregate principal amount of 4.5% senior unsecured notes due in July 2023. We received net proceeds of approximately $986.9 million. A portion of the proceeds, together with cash on hand, was used to repurchase $81.1 million aggregate principal amount of 8.75% senior notes due in April 2018, approximately $175 million of the outstanding principal amount of our 6.5% senior notes due August 2021 and approximately $245 million of the outstanding principal amount of our 6.25% senior notes due June 2022, with the remainder to be used to fund our capital expenditure program and for general partnership purposes.

*Credit Risk*

We are subject to risk of loss resulting from nonpayment by our customers to whom we provide midstream services or sell natural gas or NGLs. Our credit exposure related to these customers is represented by the value of our trade receivables. Where exposed to credit risk, we analyze the customer's financial condition prior to entering into a transaction or agreement, establish credit terms and monitor the appropriateness of these terms on an ongoing basis. In the event of a customer default, we may sustain a loss and our cash receipts could be negatively impacted.

We are subject to risk of loss resulting from nonpayment or nonperformance by the counterparties to our derivative contracts. Our credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value at the reporting date. These outstanding instruments expose us to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of our counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

## ITEM 8. Financial Statements and Supplementary Data

### Index to Consolidated Financial Statements



All schedules have been omitted because they are not required or because the required information is contained in the financial statements or notes thereto.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors of
MarkWest Energy GP, L.L.C
Denver, Colorado

We have audited the accompanying consolidated balance sheets of MarkWest Energy Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2012 and 2011, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MarkWest Energy Partners, L.P. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2013

**MARKWEST ENERGY PARTNERS, L.P.**

**CONSOLIDATED BALANCE SHEETS**

**(in thousands)**

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents ($33,727 and $2,684, respectively) | $ 347,899 | $ 117,016 |
| Restricted cash ($500 and $0, respectively) | 25,500 | 26,193 |
| Receivables, net ($1,591 and $1,569, respectively) | 198,769 | 226,561 |
| Inventories | 24,633 | 41,006 |
| Fair value of derivative instruments | 19,504 | 8,698 |
| Deferred income taxes | 5,281 | 14,885 |
| Other current assets ($264 and $169, respectively) | 35,053 | 11,748 |
| Total current assets | 656,639 | 446,107 |
| Property, plant and equipment ($568,063 and $156,808, respectively) | 5,700,176 | 3,302,369 |
| Less: accumulated depreciation ($24,636 and $15,551, respectively) | (624,548) | (438,062) |
| Total property, plant and equipment, net | 5,075,628 | 2,864,307 |
| Other long-term assets: | | |
| Restricted cash | 10,000 | — |
| Investment in unconsolidated affiliate | 31,179 | 27,853 |
| Intangibles, net of accumulated amortization of $221,416 and $168,168, respectively | 855,155 | 603,767 |
| Goodwill | 142,174 | 67,918 |
| Deferred financing costs, net of accumulated amortization of $18,567 and $13,194, respectively | 51,145 | 41,798 |
| Deferred contract cost, net of accumulated amortization of $2,574 and $2,262, respectively | 676 | 988 |
| Fair value of derivative instruments | 10,878 | 16,092 |
| Other long-term assets ($102 and $102, respectively) | 2,242 | 1,595 |
| Total assets | $6,835,716 | $4,070,425 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable ($73,883 and $96, respectively) | $ 320,645 | $ 179,871 |
| Accrued liabilities ($110,746 and $1,144, respectively) | 391,352 | 171,451 |
| Fair value of derivative instruments | 27,229 | 90,551 |
| Total current liabilities | 739,226 | 441,873 |
| Deferred income taxes | 191,318 | 93,664 |
| Fair value of derivative instruments | 32,190 | 65,403 |
| Long-term debt, net of discounts of $8,061 and $1,050, respectively | 2,523,051 | 1,846,062 |
| Other long-term liabilities ($79 and $73, respectively) | 134,340 | 121,356 |
| Commitments and contingencies (see Note 17) | | |
| Equity: | | |
| Common units (127,494 and 94,940 common units issued and outstanding, respectively) | 2,134,714 | 679,309 |
| Class B units (19,954 units issued and outstanding) | 752,531 | 752,531 |
| Non-controlling interest in consolidated subsidiaries | 328,346 | 70,227 |
| Total equity | 3,215,591 | 1,502,067 |
| Total liabilities and equity | $6,835,716 | $4,070,425 |

Asset and liability amounts in parentheses represent the portion of the consolidated balance attributable to variable interest entities.

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

**MARKWEST ENERGY PARTNERS, L.P.**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

**(in thousands, except per unit amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| Revenue: | | | |
| Revenue | $1,395,231 | $1,534,434 | $1,241,563 |
| Derivative gain (loss) | 56,535 | (29,035) | (53,932) |
| Total revenue | 1,451,766 | 1,505,399 | 1,187,631 |
| Operating expenses: | | | |
| Purchased product costs | 530,328 | 682,370 | 578,627 |
| Derivative (gain) loss related to purchased product costs | (13,962) | 52,960 | 27,713 |
| Facility expenses | 208,385 | 173,598 | 151,449 |
| Derivative loss (gain) related to facility expenses | 1,371 | (6,480) | (1,295) |
| Selling, general and administrative expenses | 94,116 | 81,229 | 75,258 |
| Depreciation | 189,549 | 149,954 | 123,198 |
| Amortization of intangible assets | 53,320 | 43,617 | 40,833 |
| Loss on disposal of property, plant and equipment | 6,254 | 8,797 | 3,149 |
| Accretion of asset retirement obligations | 677 | 1,190 | 237 |
| Total operating expenses | 1,070,038 | 1,187,235 | 999,169 |
| Income from operations | 381,728 | 318,164 | 188,462 |
| Other income (expense): | | | |
| Earnings (loss) from unconsolidated affiliates | 699 | (1,095) | 1,562 |
| Interest income | 419 | 422 | 1,670 |
| Interest expense | (120,191) | (113,631) | (103,873) |
| Amortization of deferred financing costs and discount (a component of interest expense) | (5,601) | (5,114) | (10,264) |
| Derivative gain related to interest expense | — | — | 1,871 |
| Loss on redemption of debt | — | (78,996) | (46,326) |
| Miscellaneous income, net | 62 | 144 | 1,189 |
| Income before provision for income tax | 257,116 | 119,894 | 34,291 |
| Provision for income tax (benefit) expense: | | | |
| Current | (2,366) | 17,578 | 7,655 |
| Deferred | 40,694 | (3,929) | (4,466) |
| Total provision for income tax | 38,328 | 13,649 | 3,189 |
| Net income | 218,788 | 106,245 | 31,102 |
| Net loss (income) attributable to non-controlling interest | 1,614 | (45,550) | (30,635) |
| Net income attributable to the Partnership's unitholders | $ 220,402 | $ 60,695 | $ 467 |
| Net income (loss) attributable to the Partnership's common unitholders per common unit (Note 22): | | | |
| Basic | $ 1.98 | $ 0.75 | $ (0.01) |
| Diluted | $ 1.69 | $ 0.75 | $ (0.01) |
| Weighted average number of outstanding common units: | | | |
| Basic | 109,979 | 78,466 | 70,128 |
| Diluted | 130,648 | 78,619 | 70,128 |
| Cash distribution declared per common unit | $ 3.16 | $ 2.75 | $ 2.56 |

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

## MARKWEST ENERGY PARTNERS, L.P.
## CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
### (in thousands)

| | Common Units | | Class B Units | | Non-controlling Interest | Total |
|---|---|---|---|---|---|---|
| | Units | Amount | Units | Amount | | |
| **December 31, 2009** | 66,275 | $ 1,026,814 | — | $ — | $ 282,739 | $ 1,309,553 |
| Share-based compensation activity | 278 | 12,087 | — | — | — | 12,087 |
| Excess tax benefits related to share-based compensation | — | 98 | — | — | — | 98 |
| Distributions paid | — | (181,058) | — | — | (6,150) | (187,208) |
| Issuance of units in public equity offering, net of offering costs | 4,887 | 142,255 | — | — | — | 142,255 |
| Contributions to MarkWest Liberty Midstream joint venture, net | — | — | — | — | 158,293 | 158,293 |
| Deferred income tax impact from changes in equity | — | (7,614) | — | — | — | (7,614) |
| Net income | — | 467 | — | — | 30,635 | 31,102 |
| **December 31, 2010** | 71,440 | 993,049 | — | — | 465,517 | 1,458,566 |
| Share-based compensation activity | 275 | 8,083 | — | — | — | 8,083 |
| Excess tax benefits related to share-based compensation | — | 1,084 | — | — | — | 1,084 |
| Distributions paid | — | (218,398) | — | — | (66,887) | (285,285) |
| Issuance of units in public equity offerings, net of offering costs | 23,225 | 1,095,488 | — | — | — | 1,095,488 |
| Issuance of Class B units | — | — | 19,954 | 752,531 | — | 752,531 |
| Contributions to MarkWest Liberty Midstream joint venture | — | — | — | — | 126,392 | 126,392 |
| Purchase of non-controlling interest of MarkWest Liberty M&R, net of tax benefit | — | (1,198,465) | — | — | (500,345) | (1,698,810) |
| Deferred income tax impact from changes in equity | — | (62,227) | — | — | — | (62,227) |
| Net income | — | 60,695 | — | — | 45,550 | 106,245 |
| **December 31, 2011** | 94,940 | 679,309 | 19,954 | 752,531 | 70,227 | 1,502,067 |
| Issuance of units in public offering, net of offering costs | 32,308 | 1,634,081 | — | — | — | 1,634,081 |
| Distributions paid | — | (339,967) | — | — | (5,887) | (345,854) |
| Contributions from non-controlling interest | — | — | — | — | 265,620 | 265,620 |
| Share-based compensation activity | 246 | 6,548 | — | — | — | 6,548 |
| Excess tax benefits related to share-based compensation | — | 907 | — | — | — | 907 |
| Deferred income tax impact from changes in equity | — | (66,566) | — | — | — | (66,566) |
| Net income | — | 220,402 | — | — | (1,614) | 218,788 |
| **December 31, 2012** | 127,494 | $ 2,134,714 | 19,954 | $752,531 | $ 328,346 | $ 3,215,591 |

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

## MARKWEST ENERGY PARTNERS, L.P.
## CONSOLIDATED STATEMENTS OF CASH FLOWS
## (in thousands)

| | Year ended December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| **Cash flows from operating activities:** | | | |
| Net income | $ 218,788 | $ 106,245 | $ 31,102 |
| Adjustments to reconcile net income to net cash provided by operating activities (net of acquisitions): | | | |
| Depreciation | 189,549 | 149,954 | 123,198 |
| Amortization of intangible assets | 53,320 | 43,617 | 40,833 |
| Loss on redemption of debt | — | 78,996 | 46,326 |
| Amortization of deferred financing costs and discount | 5,601 | 5,114 | 10,264 |
| Accretion of asset retirement obligations | 677 | 1,190 | 237 |
| Amortization of deferred contract cost | 312 | 312 | 312 |
| Phantom unit compensation expense | 14,615 | 13,479 | 15,319 |
| Equity in (earnings) loss of unconsolidated affiliates | (699) | 1,095 | (1,562) |
| Contribution to unconsolidated affiliate | — | (560) | — |
| Distributions from unconsolidated affiliate | 2,600 | 300 | 2,508 |
| Unrealized (gain) loss on derivative instruments | (102,127) | 4,147 | 28,475 |
| Loss on disposal of property, plant and equipment | 6,254 | 8,797 | 3,149 |
| Deferred income taxes | 40,694 | (3,929) | (4,466) |
| Other | — | 1,626 | — |
| Changes in operating assets and liabilities, net of working capital acquired: | | | |
| Receivables | 32,588 | (45,463) | (37,090) |
| Inventories | 16,580 | (16,025) | 5,710 |
| Other current assets | (23,115) | (3,728) | 2,654 |
| Accounts payable and accrued liabilities | 28,412 | 54,745 | 45,361 |
| Other long-term assets | (647) | (307) | 174 |
| Other long-term liabilities | 13,311 | 15,093 | (176) |
| Net cash provided by operating activities | 496,713 | 414,698 | 312,328 |
| **Cash flows from investing activities:** | | | |
| Restricted cash | (9,497) | 2,006 | (28,001) |
| Capital expenditures | (1,951,427) | (551,281) | (458,668) |
| Acquisition of business, net of cash acquired | (506,797) | (230,728) | — |
| Investment in unconsolidated affiliate | (5,227) | — | — |
| Proceeds from disposal of property, plant and equipment | 596 | 3,450 | 733 |
| Net cash flows used in investing activities | (2,472,352) | (776,553) | (485,936) |
| **Cash flows from financing activities:** | | | |
| Proceeds from public equity offerings, net | 1,634,081 | 1,095,488 | 142,255 |
| Proceeds from Credit facility | 511,100 | 1,182,200 | 494,404 |
| Payments of Credit facility | (577,100) | (1,116,200) | (553,704) |
| Proceeds from long-term debt | 742,613 | 1,199,000 | 500,000 |
| Payments of long-term debt | — | (693,888) | (375,000) |
| Payments of premiums on redemption of long-term debt | — | (71,377) | (9,732) |
| Payments for debt issuance costs, deferred financing costs and registration costs | (14,720) | (20,163) | (20,912) |
| Acquisition of non-controlling interest, including transaction costs | — | (997,601) | — |
| Contributions from non-controlling interest | 265,620 | 126,392 | 158,293 |
| Payments of SMR Liability | (2,058) | (1,875) | (1,354) |
| Cash paid for taxes related to net settlement of share-based payment awards | (8,067) | (6,354) | (3,834) |
| Excess tax benefits related to share-based compensation | 907 | 1,084 | 98 |
| Payment of distributions to common unitholders | (339,967) | (218,398) | (181,058) |
| Payment of distributions to non-controlling interest | (5,887) | (66,887) | (6,150) |
| Net cash flows provided by financing activities | 2,206,522 | 411,421 | 143,306 |
| Net increase (decrease) in cash and cash equivalents | 230,883 | 49,566 | (30,302) |
| Cash and cash equivalents at beginning of year | 117,016 | 67,450 | 97,752 |
| Cash and cash equivalents at end of year | $ 347,899 | $ 117,016 | $ 67,450 |

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

## MARKWEST ENERGY PARTNERS, L.P.
## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 1. Organization and Basis of Presentation

MarkWest Energy Partners, L.P. ("MarkWest Energy Partners") was formed in January 2002 as a Delaware limited partnership. MarkWest Energy Partners and its subsidiaries (collectively, the "Partnership") are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs and the gathering and transportation of crude oil. We have a leading presence in many unconventional gas plays including the Marcellus Shale, Utica Shale, Huron/Berea Shale, Haynesville Shale, Woodford Shale and Granite Wash formation. The Partnership's principal executive office is located in Denver, Colorado.

The Partnership's consolidated financial statements include all majority- owned or majority-controlled subsidiaries. In addition, MarkWest Utica EMG and MarkWest Pioneer, VIEs for which the Partnership has been determined to be the primary beneficiary, are included in the consolidated financial statements (see Note 4). For non-wholly-owned subsidiaries, the interests owned by third parties have been recorded as *Non-controlling interest in consolidated subsidiaries* in the accompanying Consolidated Balance Sheets. Intercompany investments, accounts and transactions have been eliminated. The Partnership's investment in Centrahoma in which the Partnership exercises significant influence but does not control and is not the primary beneficiary, is accounted for using the equity method. The accompanying consolidated financial statements of the Partnership have been prepared in accordance with GAAP.

### 2. Summary of Significant Accounting Policies

*Use of Estimates*

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, 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. Estimates affect, among other items, valuing identified intangible assets; determining the fair value of derivative instruments; valuing inventory; evaluating impairments of long-lived assets, goodwill and equity investments; establishing estimated useful lives for long-lived assets; recognition of share-based compensation expense; estimating revenues, expense accruals and capital expenditures; valuing asset retirement obligations; and in determining liabilities, if any, for legal contingencies.

*Cash and Cash Equivalents*

The Partnership considers investments in highly liquid financial instruments purchased with an original maturity of 90 days or less to be cash equivalents. Such investments include money market accounts.

*Restricted Cash*

Restricted cash consists primarily of cash and investments that must be maintained as collateral for letters of credit issued to certain third party producer customers. The balances will be outstanding until certain capital projects are completed and the third party releases the restriction. Restricted cash balances for which the restrictions are not expected to be released within a period of twelve months are classified as long-term assets in the Consolidated Balance Sheets.

**2. Summary of Significant Accounting Policies (Continued)**

*Inventories*

Inventories, which consist primarily of natural gas, propane, other NGLs and spare parts and supplies, are valued at the lower of weighted-average cost or fair value. Processed natural gas and NGL inventories include material, labor and overhead. Shipping and handling costs related to purchases of natural gas and NGLs are included in inventory.

*Property, Plant and Equipment*

Property, plant and equipment are recorded at cost. Expenditures that extend the useful lives of assets are capitalized. Repairs, maintenance and renewals that do not extend the useful lives of the assets are expensed as incurred. Interest costs for the construction or development of long-lived assets are capitalized and amortized over the related asset's estimated useful life. Leasehold improvements are depreciated over the shorter of the useful life or lease term. Depreciation is provided, principally on the straight-line method, over a period of 20 to 25 years for all assets, with the exception of miscellaneous equipment and vehicles, which are depreciated over a period of three to ten years.

The Partnership evaluates transactions involving the sale of property, plant and equipment to determine if they are, in-substance, the sale of real estate. Tangible assets may be considered real estate if the costs to relocate them for use in a different location exceeds 10% of the asset's fair value. Financial assets, primarily in the form of ownership interests in an entity, may be in-substance real estate based on the significance of the real estate in the entity. Sales of real estate are not considered consummated if the Partnership maintains an interest in the asset after it is sold or has certain other forms of continuing involvement. Significant judgment is required to determine if a transaction is a sale of real estate and if a transaction has been consummated. If a sale of real estate is not considered consummated, the Partnership cannot record the transaction as a sale and must account for the transaction under an alternative method of accounting such as a financing or leasing arrangement. The Partnership's sale of the SMR in 2009, which was considered in-substance real estate, was not considered a sale due to the Partnership's continuing involvement and was accounted for as a financing arrangement. See Note 5 for a description of the transaction and its impact on the financial statements.

*Asset Retirement Obligations*

An asset retirement obligation ("ARO") is a legal obligation associated with the retirement of tangible long-lived assets that generally result from the acquisition, construction, development or normal operation of the asset. AROs are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a risk free interest rate, and increases due to the passage of time based on the time value of money until the obligation is settled. The Partnership recognizes a liability of a conditional ARO as soon as the fair value of the liability can be reasonably estimated. A conditional ARO is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

**2. Summary of Significant Accounting Policies (Continued)**

*Investment in Unconsolidated Affiliate*

Equity investments in which the Partnership exercises significant influence, but does not control and is not the primary beneficiary, are accounted for using the equity method, and are reported in *Investment in unconsolidated affiliate* in the accompanying Consolidated Balance Sheets.

The Partnership believes the equity method is an appropriate means for it to recognize increases or decreases measured by GAAP in the economic resources underlying the investments. Regular evaluation of these investments is appropriate to evaluate any potential need for impairment. The Partnership uses evidence of a loss in value to identify if an investment has an other than a temporary decline.

*Intangibles*

The Partnership's intangibles are comprised of customer contracts and relationships acquired in business combinations and recorded under the acquisition method of accounting at their estimated fair values at the date of acquisition. Using relevant information and assumptions, management determines the fair value of acquired identifiable intangible assets. Fair value is generally calculated as the present value of estimated future cash flows using a risk-adjusted discount rate. The key assumptions include probability of contract renewals, economic incentives to retain customers, historical volumes, current and future capacity of the gathering system, pricing volatility and the discount rate. Amortization of intangibles with definite lives is calculated using the straight-line method over the estimated useful life of the intangible asset. The estimated economic life is determined by assessing the life of the assets related to the contracts and relationships, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions and maintenance and renewal costs.

*Goodwill*

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership evaluates goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

*Impairment of Long-Lived Assets*

The Partnership's policy is to evaluate whether there has been an impairment in the value of long-lived assets when certain events indicate that the remaining balance may not be recoverable. The Partnership evaluates the carrying value of its property, plant and equipment on at least a segment

**2. Summary of Significant Accounting Policies (Continued)**

level and at lower levels where the cash flows for specific assets can be identified and are largely independent from other asset groups. A long-lived asset group is considered impaired when the estimated undiscounted cash flows from such asset group are less than the asset group's carrying value. In that event, a loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset group. Fair value is determined primarily using estimated discounted cash flows. Management considers the volume of reserves behind the asset and future NGL product and natural gas prices to estimate cash flows. The amount of additional reserves developed by future drilling activity depends, in part, on expected natural gas prices. Projections of reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. Any significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset group.

For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value, less the cost to sell, to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

*Deferred Financing Costs*

Deferred financing costs are amortized over the contractual term of the related obligations or, in certain circumstances, accelerated if the obligation is refinanced, using the effective interest method.

*Deferred Contract Cost*

The Partnership may pay consideration to a producer upon entering a long-term arrangement to provide midstream services to the producer. In such cases, the amount of consideration paid is recorded as *Deferred contract cost, net of accumulated amortization* on the accompanying Consolidated Balance Sheets and is amortized over the term of the arrangement.

*Derivative Instruments*

Derivative instruments (including derivative instruments embedded in other contracts) are recorded at fair value and included in the Consolidated Balance Sheets as assets or liabilities. Assets and liabilities related to derivative instruments with the same counterparty are not netted in the Consolidated Balance Sheets. The Partnership discloses the fair value of all of its derivative instruments separate from other assets and liabilities under the caption *Fair value of derivative instruments* in the Consolidated Balance Sheets, inclusive of option premiums (net of amortization). Changes in the fair value of derivative instruments are reported in the Statements of Operations in accounts related to the item whose value or cash flows are being managed. Substantially all derivative instruments were marked to market through *Revenue*, *Purchased product costs*, *Facility expenses*, *Interest expense* or *Miscellaneous income (expense), net.* Revenue gains and losses relate to contracts utilized to manage the cash flow for the sale of a product and the amortization of associated option premiums. Option premiums are amortized over the effective term of the corresponding option contract. Purchased product costs gains and losses relate to contracts utilized to manage the cost of natural gas purchases, typically related to keep-whole arrangements. Facility expenses gains and losses relate to a contract utilized to manage electricity costs. Interest expense gains relate to contracts to manage the interest rate risk associated with the fair value of its fixed rate borrowings. Miscellaneous income (expense), net relate to changes

**2. Summary of Significant Accounting Policies (Continued)**

in the fair value of certain embedded put options. Changes in risk management activities are reported as an adjustment to net income in computing cash flow from operating activities on the accompanying Consolidated Statements of Cash Flows.

During 2012, 2011 and 2010, the Partnership did not designate any hedges or designate any contracts as normal purchases and normal sales.

*Fair Value of Financial Instruments*

Management believes the carrying amount of financial instruments, including cash and cash equivalents, restricted cash, receivables, accounts payable and accrued liabilities approximate fair value because of the short-term maturity of these instruments. The recorded value of the amounts outstanding under the Credit Facility approximates fair value due to the variable interest rate that approximates current market rates. Derivative instruments are recorded at fair value, based on available market information (see Note 7). The following table shows the carrying value and related fair value of financial instruments that are not recorded in the financial statements at fair value as of December 31, 2012 and 2011 (in thousands):

| | December 31, 2012 | | December 31, 2011 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Long-term debt | $2,523,051 | $2,763,080 | $1,846,062 | $1,880,710 |
| SMR Liability | 91,851 | 130,736 | 93,909 | 119,887 |

The fair value of the long-term debt is estimated based on recent market quotes. The Partnership has continued to report an asset, and the related depreciation, for the total capitalized costs of constructing the SMR and has recorded a liability equal to the proceeds from the transaction plus the estimated costs incurred by the buyer to complete construction ("SMR Liability"). The fair value of the SMR Liability is estimated using a discounted cash flow approach based on the contractual cash flows and the Partnership's unsecured borrowing rate. Both the long-term debt and SMR fair values are considered Level 3 measurements as discussed below.

*Fair Value Measurement*

Financial assets and liabilities recorded at fair value in the Consolidated Balance Sheets are categorized based upon a fair value hierarchy established by GAAP, which classifies the inputs used to measure fair value into the following levels:

- Level 1—inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2—inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3—inputs to the valuation methodology are unobservable and significant to the fair value measurement.

**2. Summary of Significant Accounting Policies (Continued)**

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

The determination to classify a financial instrument within Level 3 of the valuation hierarchy is based upon the significance of the unobservable inputs to the overall fair value measurement. However, Level 3 financial instruments typically include, in addition to the unobservable or Level 3 inputs, observable inputs (that is, inputs that are actively quoted and can be validated to external sources); accordingly, the gains and losses for Level 3 financial instruments include changes in fair value due in part to observable inputs that are part of the valuation methodology. Level 3 financial instruments include interest rate swaps, crude oil options, all NGL derivatives, and the embedded derivatives in commodity contracts discussed in Note 6 as they have significant unobservable inputs.

The methods and assumptions described above may produce a fair value that may not be realized in future periods upon settlement. Furthermore, while the Partnership believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. For further discussion see Note 7.

*Revenue Recognition*

The Partnership generates the majority of its revenues from natural gas gathering, transportation and processing; NGL gathering, transportation, fractionation, marketing and storage; and crude oil gathering and transportation. It enters into a variety of contract types. The Partnership provides services under the following different types of arrangements:

- *Fee-based arrangements*—Under fee-based arrangements, the Partnership receives a fee or fees for one or more of the following services: gathering, processing and transmission of natural gas; gathering, transportation, fractionation exchange and storage of NGLs; and gathering and transportation of crude oil. The revenue the Partnership earns from these arrangements is generally directly related to the volume of natural gas, NGLs or crude oil that flows through the Partnership's systems and facilities and is not directly dependent on commodity prices. In certain cases, the Partnership's arrangements provide for minimum annual payments or fixed demand charges.

- *Percent-of-proceeds arrangements*—Under percent-of-proceeds arrangements, the Partnership gathers and processes natural gas on behalf of producers, sells the resulting residue gas, condensate and NGLs at market prices and remits to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, the Partnership delivers an agreed-upon percentage of the residue gas and NGLs to the producer and sells the volumes the Partnership keeps to third parties.

- *Percent-of-index arrangements*—Under percent-of-index arrangements, the Partnership purchases natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount, or (3) a percentage discount to a specified index price less an additional fixed amount. The Partnership then gathers and delivers the natural gas to pipelines where the Partnership resells the natural gas at the index price or at a different percentage discount to the index price.

**2. Summary of Significant Accounting Policies (Continued)**

- *Keep-whole arrangements*—Under keep-whole arrangements, the Partnership gathers natural gas from the producer, processes the natural gas and sells the resulting condensate and NGLs to third parties at market prices. Because the extraction of the condensate and NGLs from the natural gas during processing reduces the Btu content of the natural gas, the Partnership must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require the Partnership to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the NGL to gas ratio.

Under certain contracts, the Partnership is allowed to retain a fixed percentage of the volume gathered to cover the compression fuel charges and deemed-line losses. To the extent the Partnership's gathering systems are operated more or less efficiently than specified per contract allowance, the Partnership is entitled to retain the benefit or loss for its own account.

In many cases, the Partnership provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of the Partnership's contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements. It is upon delivery and title transfer that the Partnership meets all four revenue recognition criteria and it is at such time that the Partnership recognizes revenue.

The Partnership's assessment of each of the revenue recognition criteria as they relate to its revenue producing activities is as follows:

*Persuasive evidence of an arrangement exists.* The Partnership's customary practice is to enter into a written contract, executed by both the customer and the Partnership.

*Delivery.* Delivery is deemed to have occurred at the time the product is delivered and title is transferred or, in the case of fee-based arrangements, when the services are rendered.

*The fee is fixed or determinable.* The Partnership negotiates the fee for its services at the outset of its fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue is determinable when the sale of the applicable product has been completed upon delivery and transfer of title.

*Collectability is reasonably assured.* Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates a customer's financial position (e.g. cash position and credit rating) and its ability to pay. If collectability is not considered reasonably assured at the outset of an arrangement in accordance with the Partnership's credit review process, revenue is recognized when the fee is collected.

The Partnership enters into revenue arrangements where it sells customers' gas and/or NGLs and depending on the nature of the arrangement acts as the principal or agent. Revenue from such sales is recognized gross where the Partnership acts as the principal, as the Partnership takes title to the gas and/or NGLs, has physical inventory risk and does not earn a fixed amount. Revenue is recognized net when the Partnership acts as an agent and earns a fixed amount and does not take ownership of the gas and/or NGLs.

Amounts billed to customers for shipping and handling, including fuel costs, are included in *Revenue*. Shipping and handling costs associated with product sales are included in operating expenses. Taxes collected from customers and remitted to the appropriate taxing authority are excluded from revenue.

**2. Summary of Significant Accounting Policies (Continued)**

*Revenue and Expense Accruals*

The Partnership routinely makes accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third party information and reconciling the Partnership's records with those of third parties. The delayed information from third parties includes, among other things, actual volumes purchased, transported or sold, adjustments to inventory and invoices for purchases, actual natural gas and NGL deliveries and other operating expenses. The Partnership makes accruals to reflect estimates for these items based on its internal records and information from third parties. Estimated accruals are adjusted when actual information is received from third parties and the Partnership's internal records have been reconciled.

*Incentive Compensation Plans*

The Partnership issues phantom units under its share-based compensation plans as described further in Note 19. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit. Phantom units are treated as equity awards and compensation expense is measured for these phantom unit grants based on the fair value of the units on the grant date, as defined by GAAP. The fair value of the units awarded is amortized into earnings, reduced for an estimate of expected forfeitures, over the period of service corresponding with the vesting period. For certain plans, the awards are accounted for as liability awards and the compensation expense is adjusted monthly for the change in the fair value of the unvested units granted.

To satisfy common unit awards, the Partnership may issue new common units, acquire common units in the open market, or use common units already owned by the general partner.

*Income Taxes*

The Partnership is not a taxable entity for federal income tax purposes. As such, the Partnership does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Operations, is includable in the federal income tax returns of each partner. The Partnership is, however, a taxable entity under certain state jurisdictions. The Corporation is a tax paying entity for both federal and state purposes.

In addition to paying tax on its own earnings, the Corporation recognizes a tax expense or a tax benefit on its proportionate share of Partnership income or loss resulting from the Corporation's ownership of Class A units of the Partnership even though for financial reporting purposes such income or loss is eliminated in consolidation. The Class A units represent limited partner interests with the same rights as common units except that the Class A units do not have voting rights, except as required by law. Class A units are not treated as outstanding common units in the Consolidated Balance Sheet as they are eliminated in the consolidation of the Corporation. The deferred income tax component relates to the change in the temporary book to tax basis difference in the carrying amount of the investment in the Partnership which results primarily from its timing differences in the Corporation's proportionate share of the book income or loss as compared with the Corporation's proportionate share of the taxable income or loss of the Partnership.

The Partnership and the Corporation account for income taxes under the asset and liability method. Deferred income taxes are recognized for the future tax consequences attributable to

**2. Summary of Significant Accounting Policies (Continued)**

differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis, capital loss carryforwards and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates applied to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized as tax expense (benefit) from continuing operations in the period that includes the enactment date of the tax rate change. Realizability of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to reflect the deferred tax assets at net realizable value as determined by management. Deferred tax balances that are expected to be settled within twelve months are classified as current and all other deferred tax balances are classified as long-term in the accompanying Consolidated Balance Sheets. All changes in the tax bases of assets and liabilities are allocated among continued operations and items charged or credited directly to equity.

*Earnings (Loss) Per Unit*

The Partnership's outstanding phantom units are considered to be participating securities and the Class B units are considered to be a separate class of common units that do not participate in cash distributions. Therefore, basic and diluted earnings per common unit are calculated pursuant to the two-class method described in GAAP for earnings per share. In accordance with the two-class method, basic earnings per common unit is calculated by dividing net income attributable to the Partnership's unitholders, after deducting amounts that are allocable to participating securities or separate class of common units, the outstanding phantom units and Class B units, by the weighted average number of common units outstanding during the period. The amount allocable to the phantom units and Class B units is generally calculated as if all of the net income attributable to the Partnership's unitholders were distributed and not on the basis of actual cash distributions for the period. Therefore, no earnings are allocable to Class B units as they do not participate in cash distributions. During periods in which a net loss attributable to the Partnership is reported or periods in which the total distributions exceed the reported net income attributable to the Partnership's unitholders, the amount allocable to the phantom units and Class B units is based on actual distributions to the phantom units and Class B unitholders. Diluted earnings per unit is calculated by dividing net income attributable to the Partnership's unitholders, after deducting amounts allocable to the outstanding phantom units and Class B units, by the weighted average number of potential common units outstanding during the period. Potential common units are excluded from the calculation of diluted earnings per unit during periods in which net income attributable to the Partnership's unitholders, after deducting amounts that are allocable to the outstanding phantom units and Class B units, is a loss as the impact would be anti-dilutive.

*Business Combinations*

Transactions in which the Partnership acquires control of a business are accounted for under the acquisition method. The identifiable assets, liabilities and any non-controlling interests are recorded at the estimated fair market values as of the acquisition date. The purchase price in excess of the fair value acquired is recorded as goodwill.

*Accounting for Changes in Ownership Interests in Subsidiaries*

The Partnership's ownership interest in a consolidated subsidiary may change if it sells a portion of its interest, or acquires additional interest or if the subsidiary issues or repurchases its own shares. If

**2. Summary of Significant Accounting Policies (Continued)**

the transaction does not result in a change in control over the subsidiary, the transaction is accounted for as an equity transaction. If a sale results in a change in control, it would result in the deconsolidation of a subsidiary with a gain or loss recognized in the statement of operations. If the purchase of additional interest occurs which changes the acquirer's ownership interest from non-controlling to controlling, the acquirer's preexisting interest in the acquiree is remeasured to its fair value, with a resulting gain or loss recorded in earnings upon consummation of the business combination. Once an entity has control of a subsidiary, its acquisitions of some or all of the noncontrolling interests in that subsidiary are accounted for as equity transactions and are not considered to be a business combination. See Note 4 for a description of the transactions that resulted in a change in the Partnership's ownership interest in a subsidiary and the impact of these transactions to the financial statements.

*Recent Accounting Pronouncements*

In May 2011, the FASB amended the accounting guidance for fair value measurement and disclosure. The amended guidance was intended to converge the fair value measurement and disclosure requirements under GAAP and IFRS. The amendment primarily clarifies the application of the existing guidance and provides for increased disclosures, particularly related to Level 3 fair value measurements. The amended guidance was effective for the Partnership prospectively as of January 1, 2012. Except for the additional disclosures, the adoption of the amended guidance did not have a material effect on the Partnership's consolidated financial statements.

In December 2011, the FASB amended the accounting guidance for balance sheet offsetting for financial assets and financial liabilities. The amended guidance was intended to help investors and other financial statement users to better assess the effect or potential effect of offsetting arrangements on a company's financial position and provides for increased disclosures. The amended guidance is effective for the Partnership retrospectively for all comparable periods as of January 1, 2013. Except for the additional disclosures, the adoption of the amended guidance is not expected to have a material effect on the Partnership's consolidated financial statements.

**3. Business Combinations**

*Keystone Acquisition*

On May 29, 2012, the Partnership acquired natural gas gathering and processing assets from Keystone for a cash purchase price of approximately $507.3 million, giving effect to the final working capital adjustment. The Partnership paid cash of $509.6 million in May 2012 and has recorded a receivable for the $2.3 million working capital adjustment as of December 31, 2012.

Keystone's existing assets are located in Butler County, Pennsylvania and include two cryogenic gas processing plants totaling approximately 90 MMcf/d of processing capacity, a gas gathering system and associated field compression. The acquisition is referred to as the "Keystone Acquisition".

As a result of the Keystone Acquisition, the Partnership became a party to a long-term fee-based agreement to gather and process certain natural gas owned or controlled by Rex Energy, a subsidiary of Rex Energy Corporation, and Summit, a subsidiary of Sumitomo Corporation, at the acquired facilities and in 2013 to exchange the resulting NGLs for fractionated products at facilities already owned and operated by the Partnership. Rex and Summit have dedicated an area of approximately 900 square

**3. Business Combinations (Continued)**

miles to the Partnership as part of this long-term gathering and processing agreement. As a result of the Keystone Acquisition, the Partnership has expanded its position in the liquids-rich Marcellus Shale area into northwest Pennsylvania.

The Keystone Acquisition is accounted for as a business combination. The total purchase price is allocated to identifiable assets acquired and liabilities assumed based on the estimated fair values at the acquisition date. The remaining purchase price in excess of the fair value of the identifiable assets and liabilities is recorded as goodwill. The acquired assets and the related results of operations are included in the Partnership's Liberty segment. The following table summarizes the purchase price allocation for the Keystone Acquisition (in thousands):

| | |
|---|---|
| Assets: | |
| Cash | $ 2,837 |
| Accounts receivable | 1,756 |
| Inventory | 86 |
| Property, plant and equipment | 136,593 |
| Goodwill | 74,256 |
| Intangible asset | 304,708 |
| Liabilities: | |
| Accounts payable | (12,117) |
| Other short-term liabilities | (175) |
| Other long-term liabilities | (632) |
| **Total** | $507,312 |

The goodwill recognized from the Keystone Acquisition results primarily from synergies created from integrating the Keystone assets with the Partnership's existing Marcellus Shale operations and the Partnership's strengthened competitive position as it plans to expand its business in the newly developing liquids-rich areas of the Marcellus Shale. All of the goodwill is deductible for tax purposes.

The intangible asset consists of an identifiable contractual customer relationship with Rex and Summit. The acquired intangible asset will be amortized on a straight-line basis over the estimated customer contract useful life of approximately 19 years.

The results of operations of Keystone are included in the consolidated financial statements from the acquisition date. Revenue and net income related to Keystone are immaterial for the year ended December 31, 2012.

Pro forma financial results that give effect to the Keystone Acquisition are not presented as any pro forma adjustments would not be material to the Partnership's historical results.

*Langley Acquisition*

On February 1, 2011, the Partnership acquired natural gas processing and NGL pipeline assets from EQT for a cash purchase price of approximately $230.7 million. The assets acquired include natural gas processing facilities located near Langley, Kentucky, consisting of a cryogenic natural gas processing plant with a capacity of approximately 100 MMcf/d and a refrigeration natural gas processing plant with a capacity of approximately 75 MMcf/d, the partially constructed Ranger pipeline

**3. Business Combinations (Continued)**

that extends through parts of Kentucky and West Virginia, and certain other related assets. The acquired assets do not include certain residue gas compression and transportation facilities at the same location as the Langley Processing Facilities. This acquisition is referred to as the "Langley Acquisition". In connection with the Langley Acquisition, the Partnership completed the construction of the Ranger Pipeline to connect the Langley Processing Facilities to the Partnership's existing pipeline that transports NGLs to its Siloam fractionation facility in South Shore, Kentucky.

Concurrently with the closing of the Langley Acquisition, the Partnership entered into a long-term agreement to process certain natural gas owned or controlled by EQT at the Langley Processing Facilities. In 2012, the Partnership installed an additional cryogenic natural gas processing plant with a capacity of 150 MMcf/d as required by the processing agreement. The Partnership exchanges the NGLs produced at the Langley Processing Facilities for fractionated products from its Siloam facility and markets the fractionated products on behalf of EQT in accordance with a long-term NGL exchange and marketing agreement. As a result of the acquisition, the Partnership has significantly expanded its midstream operations in the liquids-rich gas areas of the Appalachian Basin.

The Langley Acquisition is accounted for as a business combination. The total purchase price is allocated to the identifiable assets acquired and liabilities assumed based on the estimated fair values at the acquisition date. The remaining purchase price in excess of the fair value of the identifiable assets and liabilities is recorded as goodwill. The acquired assets and the related results of operations are included in the Partnership's Northeast segment.

The following table summarizes the purchase price allocation for the Langley Acquisition (in thousands):

| | |
|---|---|
| Property, plant and equipment | $136,525 |
| Goodwill | 58,497 |
| Intangible asset | 33,900 |
| Inventory | 1,806 |
| Total | $230,728 |

The goodwill recognized from the Langley Acquisition results primarily from the Partnership's ability to continue to grow its business in the liquids-rich gas areas of the Appalachian Basin and access additional markets in a competitive environment as a result of securing the processing rights for a large area of dedicated acreage and acquiring expanded midstream infrastructure in the acquisition. All of the goodwill is deductible for tax purposes.

The intangible asset consists of an identifiable customer contract. The acquired intangible will be amortized on a straight-line basis over the estimated remaining customer contract useful life of approximately twelve years.

**4. Variable Interest Entities**

*MarkWest Utica EMG*

Effective January 1, 2012, the Partnership and EMG Utica (together the "Members"), executed agreements to form a joint venture, MarkWest Utica EMG, to develop significant natural gas gathering, processing and NGL fractionation, transportation and marketing infrastructure in Eastern Ohio.

**4. Variable Interest Entities (Continued)**

Under the terms of the agreements, the Partnership made an initial contribution to MarkWest Utica EMG in a nominal amount in exchange for a 60% membership interest in MarkWest Utica EMG, and EMG Utica made an initial contribution in a nominal amount and has agreed to contribute to MarkWest Utica EMG $350 million (Initial EMG Contribution) in exchange for a 40% membership interest in MarkWest Utica EMG. Following the funding of the Initial EMG Contribution, the Partnership had the one time right to elect that the Partnership fund 60% of all capital required to develop projects within MarkWest Utica EMG until such time as EMG Utica's total investment balance equals $500 million (the "Original Minimum EMG Investment") and, in such event, EMG Utica would have been required to fund the remaining 40% of all such capital. Subsequent to December 31, 2012, the Partnership did not make this election, and as a result, EMG Utica is obligated to fund, as needed, all capital required to develop projects within MarkWest Utica EMG until such time as EMG Utica's total investment balance reaches the Original Minimum EMG Investment or, if earlier, until December 31, 2016. Once EMG Utica has funded capital equal to the Original Minimum EMG Investment or, if earlier, January 1, 2017, the Partnership is required to fund, as needed, 100% of all capital required to develop projects within MarkWest Utica EMG until such time as the total investment balances of the Partnership and EMG Utica reach the First Equalization Date. If the First Equalization Date has not occurred by December 31, 2016, each member's ownership interest will be adjusted to equal the proportionate share of capital that it has contributed, and allocations of profits and losses and distributions of available cash will be made in accordance with those adjusted membership interests. Following the First Equalization Date, the Partnership shall have the right to elect to continue to fund up to 100% of any additional capital required until such time as the investment balances of the Partnership and EMG Utica reach the Second Equalization Date. To the extent the Partnership does not fully exercise such right at any time prior to the Second Equalization Date, EMG Utica shall have the right, but not the obligation, to contribute such additional capital that is requested and that is not contributed by the Partnership. After the Second Equalization Date, EMG Utica shall have the right, but not the obligation, to maintain a 30% interest in MarkWest Utica EMG by funding 30% of any additional required capital. EMG Utica contributed $264.8 million for the year ended December 31, 2012.

Subsequent to December 31, 2012, the Partnership and EMG Utica executed the Amended Utica LLC agreement which replaces the agreement described above. See Note 28 for discussion of the terms of the Amended Utica LLC Agreement.

The Partnership has determined that MarkWest Utica EMG is a VIE primarily due to the Partnership's disproportionate economic interests as compared to its stated ownership interests and voting interests. The Partnership's 60% ownership interest in the entity is disproportionate to its economic interest due to the timing of the capital funding requirements described above. The Partnership has concluded that it is the primary beneficiary of MarkWest Utica EMG based on its role as the operator and its right to receive benefits and absorb losses of MarkWest Utica EMG. The Partnership believes that its role as the operator along with its equity interests give it the power to direct the activities that most significantly affect the economic performance of MarkWest Utica EMG.

*MarkWest Pioneer*

MarkWest Pioneer is the owner and operator of the Arkoma Connector Pipeline, a 50-mile FERC-regulated pipeline that was placed in service in mid-July 2009. The Arkoma Connector Pipeline is designed to provide approximately 638,000 Dth/d of Arkoma Basin takeaway capacity and

**4. Variable Interest Entities (Continued)**

interconnects with the Midcontinent Express Pipeline, the Gulf Crossing Pipeline and the Natural Gas Pipeline of America L.L.C. In 2009, the Partnership sold a 50% interest in MarkWest Pioneer to ArcLight Capital Partners, LLC. Under the terms of the sale, the Partnership was required to fund all of the capital expenditures required to complete construction of the Arkoma Connector Pipeline in excess of $125 million, and as a result the Partnership has made capital contributions to MarkWest Pioneer in excess of its stated ownership and voting interests. A wholly-owned subsidiary of the Partnership serves as the operator and provides field operating and general and administrative services for fixed fees. The Partnership has determined that MarkWest Pioneer is a VIE primarily due to the Partnership's disproportionate economic interests as compared to its voting interests. Although voting interests are shared equally between the respective members of MarkWest Pioneer, the Partnership has concluded that it is the primary beneficiary based on its role as the operator. The Partnership believes that its role as the operator along with its equity interests give it the power to direct the activities that most significantly affect the economic performance of MarkWest Pioneer.

*MarkWest Liberty Midstream*

In 2009, the Partnership entered into a joint venture with M&R, the joint venture entity being MarkWest Liberty Midstream, which operates in the natural gas midstream business in and around the Marcellus Shale in western Pennsylvania. The Partnership determined MarkWest Liberty Midstream was a VIE until December 31, 2011, primarily due to the Partnership's disproportionate economic interests as compared to its voting interests in the entity. Effective December 31, 2011, the partnership acquired M&R's 49% non-controlling interest of MarkWest Liberty Midstream for $994.0 million cash and approximately 19,954,000 Class B units. Therefore, MarkWest Liberty Midstream is no longer a VIE.

*Financial Statement Impact of VIEs*

As of December 31, 2011, MarkWest Pioneer is the only VIE included in the Partnership's consolidated financial statements. The assets and liabilities attributable to MarkWest Pioneer as of December 31, 2011 are disclosed parenthetically on the accompanying Consolidated Balance Sheets. As of December 31, 2012, MarkWest Pioneer and MarkWest Utica EMG were both consolidated VIEs.

**4. Variable Interest Entities (Continued)**

The following table shows the assets and liabilities attributable to VIEs reflected in the Consolidated Balance Sheets as of December 31, 2012 (in thousands):

| | MarkWest Pioneer | MarkWest Utica EMG | Total |
|---|---|---|---|
| **ASSETS** | | | |
| Cash and cash equivalents | $ 2,143 | $ 31,584 | $ 33,727 |
| Restricted cash | — | 500 | 500 |
| Receivables, net | 1,188 | 403 | 1,591 |
| Other current assets | 182 | 82 | 264 |
| Property, plant and equipment, net of accumulated depreciation of $21,849 and $2,787, respectively | 136,009 | 407,418 | 543,427 |
| Other long-term assets | 102 | — | 102 |
| Total assets | $139,624 | $439,987 | $579,611 |
| **LIABILITIES** | | | |
| Accounts payable | $ 18 | $ 73,865 | $ 73,883 |
| Accrued liabilities | 1,174 | 109,572 | 110,746 |
| Other long-term liabilities | 79 | — | 79 |
| Total liabilities | $ 1,271 | $183,437 | $184,708 |

The assets of the VIEs are not available to the Partnership for any other purpose, including collateral for its secured debt (see Note 15 and Note 24). VIE asset balances can only be used to settle obligations of each respective VIE and not those of the Partnership or any other subsidiaries of the Partnership. The liabilities of the VIEs do not represent additional claims against the Partnership's general assets and the creditors or beneficial interest holders of the VIEs do not have recourse to the general credit of the Partnership. The Partnership's maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment, any additional capital contribution commitments and any operating expense incurred by the subsidiary operator in excess of its compensation received for the performance of the operating services. The Partnership may temporarily fund MarkWest Utica EMG for certain projects due to the timing of the capital call process. The Partnership will receive distributions as reimbursement for any such temporary funding. Other than temporary funding, the Partnership did not provide any financial support to the VIEs that it was not contractually obligated to provide during the years ended December 31, 2012 and 2011. All temporary funding was distributed back to the Partnership as of December 31, 2012.

The results of operations of MarkWest Utica EMG and its subsidiaries are shown separately as the Utica segment and MarkWest Pioneer results are included in the Partnership's Southwest segment (see Note 23). The results of operations and cash flows for MarkWest Pioneer are not material to the Partnership.

As discussed above, the Partnership's ownership interest in MarkWest Liberty Midstream changed as a result of a transaction completed in 2011. The following table summarizes the effect of the change

**4. Variable Interest Entities (Continued)**

of ownership interest on the equity attributable to the Partnership's common units for the year ended December 31, 2011 (in thousands):

| | |
|---|---|
| Net income (loss) attributable to the Partnership | $ 60,695 |
| Transfers to the non-controlling interests: | |
| Decrease in common unit equity for 2011 acquisition of equity interest in MarkWest Liberty Midstream, net of $51,321 income tax benefit | (1,194,865) |
| Decrease in common unit equity for transaction costs related to 2011 acquisition of equity interest in MarkWest Liberty Midstream | (3,600) |
| Net (loss) income attributable to the Partnership and transfers to the non-controlling interest | $(1,137,770) |

**5. SMR Transaction**

On September 1, 2009, the Partnership completed the SMR Transaction. At that time, the Partnership had begun constructing the SMR at its Javelina gas processing and fractionation facility in Corpus Christi, Texas. Under the terms of the agreement, the Partnership received proceeds of $73.1 million and the purchaser completed the construction of the SMR. The Partnership and the purchaser also executed a related product supply agreement under which the Partnership will receive all of the product produced by the SMR through 2030 in exchange for processing fees and the reimbursement of certain other expenses. The processing fee payments began when the SMR commenced operations in March 2010. The Partnership is deemed to have continuing involvement with the SMR as a result of certain provisions in the related agreements. Therefore, the transaction is treated as a financing arrangement under GAAP. The Partnership imputes interest on the SMR Liability at 9.35% annually, its incremental borrowing rate at transaction consummation. The accrued interest on the SMR Liability was capitalized until the SMR commenced operations and the Partnership began payment of the processing fee under the product supply agreement. Each processing fee payment has multiple elements: reduction of principal of the SMR Liability, interest expense associated with the SMR Liability, and facility expense related to the operation of the SMR. As of December 31, 2012 and 2011, the following amounts related to the SMR are included in the accompanying Consolidated Balance Sheets (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| **ASSETS** | | |
| Property, plant and equipment, net of accumulated depreciation of $14,926 and $9,658, respectively | $90,437 | $95,705 |
| **LIABILITIES** | | |
| Accrued liabilities | $ 2,259 | $ 2,058 |
| Other long-term liabilities | 89,592 | 91,851 |

**6. Derivative Financial Instruments**

*Commodity Derivatives*

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty, availability of NGL transportation and fractionation capacity and a variety of additional factors that are beyond the Partnership's control. The Partnership's profitability is directly affected by prevailing commodity prices primarily as a result of processing or conditioning at its own or third-party processing plants, purchasing and selling, or gathering and transporting, volumes of natural gas at index-related prices and the cost of third-party transportation and fractionation services. To the extent that commodity prices influence the level of natural gas drilling by the Partnership's producer customers, such prices also affect profitability. To protect itself financially against adverse price movements and to maintain more stable and predictable cash flows so that the Partnership can meet its cash distribution objectives, debt service and capital expenditures, the Partnership executes a strategy governed by the risk management policy approved by the General Partner's board of directors (the "Board"). The Partnership has a committee comprised of senior management that oversees risk management activities (the "Hedge Committee"), continually monitors the risk management program and adjusts its strategy as conditions warrant. The Partnership enters into certain derivative contracts to reduce the risks associated with unfavorable changes in the prices of natural gas, NGLs and crude oil. Derivative contracts utilized are swaps and options traded on the OTC market and fixed price forward contracts. The risk management policy does not allow the Partnership to take speculative positions with its derivative contracts.

To mitigate its cash flow exposure to fluctuations in the price of NGLs, the Partnership has entered into derivative financial instruments relating to the future price of NGLs and crude oil. The Partnership manages a portion of its NGL price risk using crude oil contracts, referred to as "proxy contracts," as the NGL financial markets are not as liquid and historically there has been a strong relationship between changes in NGL and crude oil prices. The pricing relationship between NGLs and crude oil, which may vary in certain periods due to various market conditions, has significantly weakened during 2012. In periods where NGL prices and crude oil prices are not consistent with the historical relationship, the Partnership incurs increased risk and additional gains or losses. The Partnership may settle its derivative positions prior to the contractual settlement date in order to take advantage of favorable terms at which the Partnership could settle these proxy contracts that are expected to be less effective. The Partnership enters into NGL derivative contracts when adequate market liquidity exists and future prices are satisfactory.

To mitigate its cash flow exposure to fluctuations in the price of natural gas, the Partnership utilizes derivative financial instruments relating to the future price of natural gas and takes into account the partial offset of its long and short gas positions resulting from normal operating activities.

As a result of its current derivative positions, the Partnership has mitigated a portion of its expected commodity price risk through the fourth quarter of 2014. The Partnership would be exposed to additional commodity risk in certain situations such as if producers under deliver or over deliver product or when processing facilities are operated in different recovery modes. In the event the Partnership has derivative positions in excess of the product delivered or expected to be delivered, the excess derivative positions may be terminated.

The Partnership enters into derivative contracts primarily with financial institutions that are participating members of the Credit Facility ("participating bank group members"). Currently, all of the Partnership's financial derivative positions are with participating bank group members. A separate

**6. Derivative Financial Instruments (Continued)**

agreement with certain bank group members allows MarkWest Liberty Midstream to enter into derivative positions without posting cash collateral. Management conducts a standard credit review on counterparties to derivative contracts. There are no collateral requirements for derivative contracts among the Partnership and any participating bank group members. Specifically, the Partnership is not required to post collateral when it enters into derivative contracts with participating bank group members as the participating bank group members have a collateral position in substantially all the wholly-owned assets of the Partnership other than MarkWest Liberty Midstream and its subsidiaries. The Partnership uses standard master netting arrangements that allow for offset of positive and negative exposures.

The Partnership records derivative contracts at fair value in the Consolidated Balance Sheets and has not elected hedge accounting or the normal purchases and normal sales designation. The Partnership's accounting may cause volatility in the Consolidated Statements of Operations as the Partnership recognizes in current earnings all unrealized gains and losses from the changes in fair value on derivatives.

*Volume of Commodity Derivative Activity*

As of December 31, 2012, the Partnership had the following outstanding commodity contracts that were executed to manage the cash flow risk associated with future sales of NGLs or future purchases of natural gas.

| Derivative contracts not designated as hedging instruments | Position | Notional Quantity (net) |
|---|---|---|
| Crude Oil (bbl) | Short | 3,470,375 |
| Natural Gas (MMBtu) | Long | 5,655,676 |
| NGLs (gal) | Short | 78,012,934 |

*Embedded Derivatives in Commodity Contracts*

The Partnership has a commodity contract with a producer in the Appalachia region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. This contract is accounted for as an embedded derivative and is recorded at fair value. The changes in fair value of this commodity contract are based on the difference between the contractual and index pricing and are recorded in earnings through *Derivative loss related to purchased product costs*. In February 2011, the Partnership executed agreements with the producer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022, with the producer's option to extend the agreement for successive five year terms through December 31, 2032. As of December 31, 2012, the estimated fair value of this contract was a liability of $93.6 million and the recorded value was a liability of $40.1 million. The recorded liability does not include the inception fair value of the commodity contract related to the extended period from April 1, 2015 to December 31, 2022. In accordance with GAAP for non-option embedded derivatives, the fair value of this extended portion of the commodity contract at its inception of February 1, 2011 is deemed to be allocable to the host processing contract and, therefore, not recorded as a derivative liability. See the following table for a

**6. Derivative Financial Instruments (Continued)**

reconciliation of the liability recorded for the embedded derivative as of December 31, 2012 (in thousands).

| | |
|---|---|
| Fair value of commodity contract | $ 93,610 |
| Inception value for period from April 1, 2015 to December 31, 2022. | (53,507) |
| Derivative liability as of December 31, 2012 | $ 40,103 |

The Partnership has a commodity contract that gives it an option to fix a component of the utilities cost to an index price on electricity at its plant location in the Southwest segment through the fourth quarter of 2014. Changes in the fair value of the derivative component of this contract are recognized as *Derivative gain related to facility expenses*. As of December 31, 2012 and 2011, the estimated fair value of this contract was an asset of $6.1 million and $7.5 million, respectively.

*Interest Rate Contracts*

The Partnership borrows funds using a combination of fixed and variable rate debt. The Partnership may utilize interest rate swap contracts to manage the interest rate risk associated with the fair value of its fixed rate borrowings and to effectively convert a portion of the underlying cash flows related to its long-term fixed rate debt securities into variable rate cash flows in order to achieve its desired mix of fixed and variable rate debt. As a result, the Partnership's future cash flows from these agreements will vary with the market rate of interest.

During the first quarter of 2010, the Partnership terminated all of its outstanding interest rate swap contracts. The financial statement impact is disclosed in the tables below.

**6. Derivative Financial Instruments (Continued)**

*Financial Statement Impact of Derivative Contracts*

The impact of the Partnership's derivative instruments on its Consolidated Balance Sheets and Statements of Operations are summarized below (in thousands):

| Derivative contracts not designated as hedging instruments and their balance sheet location | Assets | | Liabilities | |
|---|---|---|---|---|
| | Fair Value at December 31, 2012 | Fair Value at December 31, 2011 | Fair Value at December 31, 2012 | Fair Value at December 31, 2011 |
| *Commodity contracts(1)* | | | | |
| Fair value of derivative instruments—current | $19,504 | $ 8,698 | $(27,229) | $ (90,551) |
| Fair value of derivative instruments—long-term | 10,878 | 16,092 | (32,190) | (65,403) |
| Total | $30,382 | $24,790 | $(59,419) | $(155,954) |

(1) Includes *Embedded Derivatives in Commodity Contracts* as discussed above.

| Derivative contracts not designated as hedging instruments and the location of gain or (loss) recognized in income | Year ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| *Revenue: Derivative gain (loss)* | | | |
| Realized loss | $ (6,508) | $(48,093) | $(33,560) |
| Unrealized gain (loss) | 63,043 | 19,058 | (20,372) |
| Total revenue: derivative gain (loss) | 56,535 | (29,035) | (53,932) |
| *Derivative gain (loss) related to purchased product costs* | | | |
| Realized (loss) | (26,493) | (27,711) | (21,909) |
| Unrealized gain (loss) | 40,455 | (25,249) | (5,804) |
| Total derivative gain (loss) related to purchase product costs | 13,962 | (52,960) | (27,713) |
| *Derivative (loss) gain related to facility expenses* | | | |
| Unrealized (loss) gain | (1,371) | 6,480 | 1,295 |
| *Derivative gain related to interest expense* | | | |
| Realized gain | — | — | 2,380 |
| Unrealized loss | — | — | (509) |
| Total derivative gain related to interest expense | — | — | 1,871 |
| *Miscellaneous income, net* | | | |
| Unrealized gain | — | — | 190 |
| Total gain (loss) | $ 69,126 | $(75,515) | $(78,289) |

At December 31, 2012 and 2011, the fair value of the Partnership's commodity derivative contracts does not include any value for premium payments. For 2012, 2011 and 2010, the *Realized (loss) gain—revenue* includes amortization of premium payments of zero, $4.4 million and $3.3 million, respectively.

During the year ended 2012, the Partnership settled a portion of its crude oil derivative positions related to 2013 and 2014 commodity price exposure prior to the contractual settlement date in order to take advantage of favorable crude oil prices at which the Partnership could settle these proxy contracts

**6. Derivative Financial Instruments (Continued)**

that are expected to be less effective. The Partnership has opportunistically entered into future NGL risk management transactions to manage the 2013 and 2014 NGL price exposure. Upon early settlement, the Partnership received $15.1 million which was recorded as a realized gain in *Revenue: Derivative gain (loss)* in the accompanying Consolidated Statements of Operations.

**7. Fair Value**

*Fair Value Measurement*

Fair value measurements and disclosures relate primarily to the Partnership's derivative positions discussed in Note 6.

The derivative contracts are measured at fair value on a recurring basis and classified within Level 2 and Level 3 of the valuation hierarchy. The Level 2 and Level 3 measurements are obtained using a market approach. LIBOR rates are an observable input for the measurement of all derivative contracts. The measurements for all commodity contracts contain observable inputs in the form of forward prices based on WTI crude oil prices; Columbia Appalachia, Henry Hub, PEPL and Houston Ship Channel natural gas prices; Mont Belvieu and Conway NGL prices; and ERCOT electricity prices. Level 2 instruments include crude oil and natural gas swap contracts. The valuations are based on the appropriate commodity prices and contain no significant unobservable inputs. Level 3 instruments include crude oil options, all NGL transactions and embedded derivatives in commodity contracts. The significant unobservable inputs for crude oil options, NGL transactions and embedded derivatives in commodity contracts include option volatilities and commodity prices interpolated and extrapolated due to inactive markets and probability of renewal. The following table presents the financial instruments carried at fair value as of December 31, 2012 and 2011, and by the valuation hierarchy (in thousands):

| As of December 31, 2012 | Assets | Liabilities |
|---|---|---|
| *Significant other observable inputs (Level 2)* | | |
| Commodity contracts | $ 8,441 | $(15,970) |
| *Significant unobservable inputs (Level 3)* | | |
| Commodity contracts | 15,795 | (3,346) |
| Embedded derivatives in commodity contracts | 6,146 | (40,103) |
| Total carrying value in Consolidated Balance Sheet | $30,382 | $(59,419) |

| As of December 31, 2011 | Assets | Liabilities |
|---|---|---|
| *Significant other observable inputs (Level 2)* | | |
| Commodity contracts | $ 5,063 | $ (79,358) |
| *Significant unobservable inputs (Level 3)* | | |
| Commodity contracts | 12,210 | (15,175) |
| Embedded derivatives in commodity contracts | 7,517 | (61,421) |
| Total carrying value in Consolidated Balance Sheet | $24,790 | $(155,954) |

## 7. Fair Value (Continued)

The following table provides additional information about the significant unobservable inputs used in the valuation of Level 3 instruments as of December 31, 2012. The market approach is used for valuation of all instruments.

| Level 3 Instrument | Balance Sheet Classification | Unobservable Inputs | Value Range | Time Period |
|---|---|---|---|---|
| Commodity contracts . . | Assets | Forward propane prices (per gallon) | \$0.91 - \$1.01 | Jan. 2013 - Dec. 2014 |
| | | Forward isobutane prices (per gallon) | \$1.70 - \$1.76 | Mar. 2013 - Mar. 2014 |
| | | Forward normal butane prices (per gallon) | \$1.52 - \$1.62 | Mar. 2013 - Dec. 2014 |
| | | Forward natural gasoline prices (per gallon) | \$1.97 - \$2.21 | Jan. 2013 - Dec. 2014 |
| | | Crude option volatilities (%) | 15.12% - 29.71% | Jan. 2013 - Dec. 2014 |
| | Liabilities | Forward propane prices (per gallon) | \$0.91 - \$0.92 | Jan. 2013 - Mar. 2013 |
| | | Forward isobutane prices (per gallon) | \$1.70 - \$1.84 | Jan. 2013 - Dec. 2014 |
| | | Forward normal butane prices (per gallon) | \$1.52 - \$1.73 | Jan. 2013 - Dec. 2013 |
| | | Forward natural gasoline prices (per gallon) | \$2.04 - \$2.21 | Jan. 2013 - Dec. 2013 |
| | | Crude option volatilities (%) | 15.05% - 30.17% | Jan. 2013 - Dec. 2013 |
| Embedded derivatives in commodity contracts . | Asset | ERCOT Pricing (per MegaWatt Hour)(1) | \$28.79 - \$62.10 | Jan. 2013 - Dec. 2014 |
| | Liability | Forward propane prices (per gallon) | \$0.91 - \$1.01 | Jan. 2013 - Dec. 2022 |
| | | Forward isobutane prices (per gallon) | \$1.60 - \$1.84 | Jan. 2013 - Dec. 2022 |
| | | Forward normal butane prices (per gallon) | \$1.44 - \$1.73 | Jan. 2013 - Dec. 2022 |
| | | Forward natural gasoline prices (per gallon) | \$1.84 - \$2.21 | Jan. 2013 - Dec. 2022 |
| | | Forward natural gas prices (per mmbtu) | \$3.33 - \$6.22 | Jan. 2013 - Dec. 2022 |
| | | Probability of renewal(2) | 0% | |

(1) The forward ERCOT prices utilized in the valuations are generally increasing over time with a seasonal spike in pricing in the summer months.

**7. Fair Value (Continued)**

(2) The producer counterparty to the embedded derivative has the option to renew the gas purchase agreement and the related keep-whole processing agreement for two successive five year terms after 2022. The embedded gas purchase agreement cannot be renewed without the renewal of the related keep-whole processing agreement. Due to the significant number of years until the renewal options are exercisable and the high level of uncertainty regarding the counterparty's future business strategy, the future commodity price environment, and the future competitive environment for midstream services in the Appalachia area, management determined that a 0% probability of renewal is an appropriate assumption.

*Fair Value Sensitivity Related to Unobservable Inputs*

*Commodity contracts (assets and liabilities)*—For the Partnership's commodity contracts, increases in forward NGL prices result in a decrease in the fair value of the derivative assets and an increase in the fair value of the derivative liabilities. The forward prices for the individual NGL products generally increase or decrease in a positive correlation with one another. An increase in crude option volatilities will generally result in an increase in the fair value of the Partnership's derivative assets and derivative liabilities in commodity contracts.

*Embedded derivative in commodity contracts (liability)*—The embedded derivative liability relates to the natural gas purchase agreement embedded in a keep-whole processing agreement as discussed further in Note 6. Increases (decreases) in forward NGL prices result in an increase (decrease) in the fair value of the embedded derivative liability. An increase in the probability of renewal would result in an increase in the fair value of the related embedded derivative liability.

*Embedded derivative in commodity contracts (asset)*—The embedded derivative asset relates to utilities costs discussed further in Note 6. Increases in the forward ERCOT prices, relative to natural gas prices, result in an increase in the fair value of the embedded derivative asset.

*Level 3 Valuation Process*

The Partnership's Risk Management Department (the "Risk Department") is responsible for the valuation of the Partnership's commodity derivative contracts and embedded derivatives in commodity contracts. The Risk Department reports to the Chief Financial Officer and is responsible for the oversight of the Partnership's commodity risk management program. The members of the Risk Department have the requisite experience, knowledge and day-to-day involvement in the energy commodity markets to ensure appropriate valuations and understand the changes in the valuations from period to period. The valuations of the Level 3 commodity derivative contracts are performed by a third-party pricing service and reviewed and validated on a quarterly basis by the Risk Department by comparing the pricing and option volatilities to actual market data and/or data provided by at least one other independent third-party pricing service. The valuations for the embedded derivatives in commodity contracts are completed by the Risk Department utilizing the market data and price curves provided by the third-party pricing service. For the embedded derivative in the keep-whole processing arrangement discussed in Note 6, the Risk Department must develop forward price curves for NGLs and natural gas for periods in which price curves are not available from third-party pricing services due to insufficient market data. As of December 31, 2012, the Risk Department utilized internally developed price curves for the period of January 2015 through December 2022 in the valuation of the embedded derivative in the keep-whole processing arrangement. In developing the pricing curves for these periods, the Risk Department maximizes its use of the latest known market data and trends as well as its understanding of the historical relationships between the forward NGL and natural gas

**7. Fair Value (Continued)**

prices and the forward market data that is available for the required period, such as crude oil pricing and natural gas pricing from other markets. However, there is very limited actual market data available to validate the Partnership's estimated price curves.

*Changes in Level 3 Fair Value Measurements*

The tables below include a rollforward of the balance sheet amounts for the years ended December 31, 2012 and 2011 (including the change in fair value) for assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy (in thousands):

| | Year Ended December 31, 2012 | |
|---|---|---|
| | Commodity Derivative Contracts (net) | Embedded Derivatives in Commodity Contracts (net) |
| Fair value at beginning of period | $ (2,965) | $(53,904) |
| Total gain or loss (realized and unrealized) included in earnings(1) | 17,153 | 9,199 |
| Settlements | (1,739) | 10,748 |
| Fair value at end of period | $12,449 | $(33,957) |
| The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at end of period | $ 8,213 | $ 8,175 |

| | Year Ended December 31, 2011 | |
|---|---|---|
| | Commodity Derivative Contracts (net) | Embedded Derivatives in Commodity Contracts (net) |
| Fair value at beginning of period | $(14,357) | $(34,936) |
| Total gain or loss (realized and unrealized) included in earnings(1) | 3,182 | (30,827) |
| Settlements | 8,210 | 11,859 |
| Fair value at end of period | $ (2,965) | $(53,904) |
| The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at end of period | $ 6,241 | $(29,556) |

(1) Gains and losses on Commodity Derivative Contracts classified as Level 3 are recorded in *Derivative (loss) gain related to revenue*. Gains and losses on Embedded Derivatives in Commodity Contracts are recorded in *Purchased product costs, Derivative loss related to purchased product costs* and *Derivative gain related to facility expenses*.

## 8. Significant Customers and Concentration of Credit Risk

For the years ended December 31, 2012, 2011 and 2010, revenues from a single customer totaled $175.1 million, $203.3 million and $115.0 million, representing 12.6%, 13.2% and 9.3% of *Revenue*, respectively. Revenues from this customer are for NGL sales made primarily from the Southwest segment. As of December 31, 2012 and 2011, the Partnership had $12.5 million and $21.9 million of accounts receivable from this customer, respectively.

For the years ended December 31, 2012, 2011 and 2010, revenues from another customer totaled $165.3 million, $297.8 million and $198.6 million, representing 11.8%, 19.4% and 16.0% of *Revenue*, respectively. Revenues from this customer are for NGL sales made primarily in the Southwest segment. As of December 31, 2012 and 2011, the Partnership had $3.9 million and $8.0 million of accounts receivable from this customer, respectively.

## 9. Receivables

Receivables consist of the following (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| Trade, net | $188,250 | $221,343 |
| Other | 10,519 | 5,218 |
| Total receivables | $198,769 | $226,561 |

## 10. Inventories

Inventories consist of the following (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| NGLs | $14,763 | $32,352 |
| Spare parts, materials and supplies | 9,870 | 8,654 |
| Total inventories | $24,633 | $41,006 |

## 11. Property, Plant and Equipment

Property, plant and equipment consist of the following (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| Natural gas gathering and NGL transportation pipelines and facilities | $2,860,124 | $2,039,524 |
| Processing plants | 894,282 | 660,928 |
| Fractionation and storage facilities | 207,169 | 120,474 |
| Crude oil pipelines | 16,730 | 16,678 |
| Land, building, office equipment and other | 386,264 | 185,462 |
| Construction in progress | 1,335,607 | 279,303 |
| Property, plant and equipment | 5,700,176 | 3,302,369 |
| Less: accumulated depreciation | (624,548) | (438,062) |
| Total property, plant and equipment, net | $5,075,628 | $2,864,307 |

## 12. Goodwill and Intangible Assets

*Goodwill.* The table below shows the gross amount of goodwill acquired and the cumulative impairment loss recognized as of December 31, 2012 (in thousands).

| | Southwest | Northeast | Liberty | Total |
|---|---|---|---|---|
| Gross goodwill as of December 31, 2011 | $ 34,178 | $62,445 | $ — | $ 96,623 |
| Acquisition(1) | — | — | 74,256 | 74,256 |
| Gross goodwill as of December 31, 2012 | 34,178 | 62,445 | 74,256 | 170,879 |
| Cumulative impairment(2) | (28,705) | — | — | (28,705) |
| Balance as of December 31, 2012 | $ 5,473 | $62,445 | $74,256 | $142,174 |

(1) Represents goodwill associated with the Keystone Acquisition (see Note 3).

(2) All impairments recorded in the fourth quarter of 2008.

*Intangible Assets.* The Partnership's intangible assets as of December 31, 2012 and 2011 are comprised of customer contracts and relationships, as follows (in thousands):

| | December 31, 2012 | | | December 31, 2011 | | | |
|---|---|---|---|---|---|---|---|
| Description | Gross | Accumulated Amortization | Net | Gross | Accumulated Amortization | Net | Useful Life |
| Southwest | $ 669,390 | $(173,317) | $496,073 | $669,462 | $(139,131) | $530,331 | 10 - 25 yrs |
| Northeast | 102,473 | (38,719) | 63,754 | 102,473 | (29,037) | 73,436 | 12 yrs |
| Liberty | 304,708 | (9,380) | 295,328 | — | — | — | 19 yrs |
| Total | $1,076,571 | $(221,416) | $855,155 | $771,935 | $(168,168) | $603,767 | |

## 12. Goodwill and Intangible Assets (Continued)

Estimated future amortization expense related to the intangible assets at December 31, 2012 is as follows (in thousands):

| Year ending December 31, | |
|---|---|
| 2013 | $ 60,234 |
| 2014 | 60,234 |
| 2015 | 60,234 |
| 2016 | 60,234 |
| 2017 | 60,234 |
| Thereafter | 553,985 |
| | $855,155 |

## 13. Accrued Liabilities and Other Long-Term Liabilities

Accrued liabilities as of December 31, 2012 and 2011 consist of the following (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| Accrued property, plant and equipment | $276,402 | $ 87,098 |
| Interest | 38,647 | 27,458 |
| Product and operations | 34,165 | 22,969 |
| Employee compensation | 15,356 | 12,600 |
| Taxes (other than income tax) | 10,619 | 9,914 |
| Other | 16,163 | 11,412 |
| Total accrued liabilities | $391,352 | $171,451 |

Other long-term liabilities as of December 31, 2012 and 2011 consist of the following (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| SMR Liability (see Note 5) | $ 89,592 | $ 91,851 |
| Deferred revenue | 33,139 | 19,383 |
| Asset retirement obligation (See Note 14) | 8,548 | 6,818 |
| Other | 3,061 | 3,304 |
| Total other long-term liabilities | $134,340 | $121,356 |

## 14. Asset Retirement Obligations

The Partnership's assets subject to asset retirement obligations are primarily certain gas-gathering pipelines and processing facilities, a crude oil pipeline and other related pipeline assets. The Partnership also has land leases that require the Partnership to return the land to its original condition upon termination of the lease. The Partnership reviews current laws and regulations governing obligations for asset retirements and leases, as well as the Partnership's leases and other agreements.

**14. Asset Retirement Obligations (Continued)**

The following is a reconciliation of the changes in the asset retirement obligation from January 1, 2011 to December 31, 2012 (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| Beginning asset retirement obligation | $6,818 | $4,029 |
| Liabilities incurred | 1,053 | 1,599 |
| Accretion expense | 677 | 1,190 |
| Ending asset retirement obligation | $8,548 | $6,818 |

At December 31, 2012, 2011 and 2010, there were no assets legally restricted for purposes of settling asset retirement obligations. The asset retirement obligation has been recorded as part of *Other long-term liabilities* in the accompanying Consolidated Balance Sheets.

In addition to recorded asset retirement obligations, the Partnership has other asset retirement obligations related to certain gathering, processing and other assets as a result of environmental and other legal requirements. The Partnership is not required to perform such work until it permanently ceases operations of the respective assets. Because the Partnership considers the operational life of these assets to be indeterminable, an associated asset retirement obligation cannot be calculated and is not recorded.

**15. Long-Term Debt**

Debt is summarized below (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| **Credit Facility** | | |
| Revolving credit facility, variable interest, due September 2017(1) | $ — | $ 66,000 |
| **Senior Notes** | | |
| 2018 Senior Notes, 8.75% interest, net of discount of $109 and $129, respectively, issued April and May 2008 and due April 2018 | 81,003 | 80,983 |
| 2020 Senior Notes, 6.75% interest, issued November 2010 and due November 2020 | 500,000 | 500,000 |
| 2021 Senior Notes, 6.5% interest, net of discount of $826 and $921, respectively, issued February and March 2011 and due August 2021 | 499,174 | 499,079 |
| 2022 Senior Notes, 6.25% interest, issued October 2011 and due June 2022 | 700,000 | 700,000 |
| 2023A Senior Notes, 5.5% interest, net of discount of $7,126, issued August 2012 and due February 2023 | 742,874 | — |
| Total long-term debt | $2,523,051 | $1,846,062 |

(1) Applicable interest rate was 4.75% at December 31, 2012.

**15. Long-Term Debt (Continued)**

*Credit Facility*

On June 29, 2012, the Partnership amended its Credit Facility to increase the borrowing capacity to $1.2 billion and retained the existing accordion option, providing for potential future increases of up to an aggregate of $250 million upon the satisfaction of certain requirements. The term of the Credit Facility was extended one year and now matures on September 7, 2017. The Partnership incurred approximately $2.5 million, $2.1 million and $11.2 million of deferred financing costs associated with modifications of the Credit Facility during the years ended December 31, 2012, 2011 and 2010, respectively.

The borrowings under the Credit Facility bear interest at a variable interest rate, plus basis points. The variable interest rate is based either on the London interbank market rate ("LIBO Rate Loans"), or the higher of (a) the prime rate set by the Facility's administrative agent, (b) the Federal Funds Rate plus 0.50% and (c) the rate for LIBO Rate Loans for a one month interest period plus 1% ("Alternate Base Rate Loans"). The basis points correspond to the Partnership's Total Leverage Ratio (which is the ratio of the Partnership's consolidated funded debt to the Partnership's adjusted consolidated EBITDA), ranging from 0.75% to 1.75% for Alternate Base Rate Loans and from 1.75% to 2.75% for LIBO Rate Loans. The Partnership may utilize up to $150 million of the Credit Facility for the issuance of letters of credit and $10 million for shorter-term swingline loans.

Under the provisions of the Credit Facility and indentures, the Partnership is subject to a number of restrictions and covenants. The Credit Facility and indentures place limits on the ability of the Partnership and its restricted subsidiaries to incur additional indebtedness; declare or pay dividends or distributions or redeem, repurchase or retire equity interests or subordinated indebtedness; make investments; incur liens; create any consensual limitation on the ability of the Partnership's restricted subsidiaries to pay dividends or distributions, make loans or transfer property to the Partnership; engage in transactions with the Partnership's affiliates; sell assets, including equity interests of the Partnership's subsidiaries; make any payment on or with respect to, or purchase, redeem, defease or otherwise acquire or retire for value any subordinated obligation or guarantor subordination obligation (except principal and interest at maturity); and consolidate, merge or transfer assets. The Credit Facility also limits the Partnership's ability to enter into transactions with parties that require margin calls under certain derivative instruments. Under the Credit Facility, neither the Partnership nor the bank can require margin calls for outstanding derivative positions.

Significant financial covenants under the Credit Facility include the Interest Coverage Ratio (as defined in the Credit Facility), which must be greater than 2.75 to 1.0, and the Total Leverage Ratio (as defined in the Credit Facility), which must be less than 5.5 to 1.0. As of December 31, 2012, the Partnership was in compliance with these covenants. These covenants are used to calculate the available borrowing capacity on a quarterly basis. On December 20, 2012 the Partnership amended the Credit Facility to increase the maximum permissible total leverage ratio from 5.25 to 1 to 5.5 to 1 for all quarters ending on or before December 31, 2013, thereby increasing the amount available for borrowing in 2013. The Credit Facility is guaranteed by, and collateralized by substantially all assets of, the Partnership's wholly- owned subsidiaries, other than MarkWest Liberty Midstream and its subsidiaries. As of December 31, 2012, the Partnership had no borrowings outstanding and $11.6 million of letters of credit outstanding under the Credit Facility, leaving approximately $1,188.4 million available for borrowing of which approximately $680 million was available for

**15. Long-Term Debt (Continued)**

borrowing based on financial covenant requirements. Additionally, the full amount of unused capacity is available for borrowing on a short term basis to provide financial flexibility within a given fiscal quarter.

*Senior Notes*

*2014 Senior Notes.* In October 2004, the Partnership and its wholly-owned subsidiary, MarkWest Energy Finance Corporation (the "Issuers") completed a private placement, subsequently registered, of $225 million in senior notes at a fixed rate of 6.875%, payable semi-annually in arrears on May 1 and November 1, commencing May 1, 2005. In May 2009, the Issuers completed an additional private placement, subsequently registered, of $150 million in aggregate principal amount of 6.875% senior unsecured notes to qualified institutional buyers under Rule 144A under an indenture substantially similar to the indenture relating to the notes issued in October 2004. The 2014 Senior Notes were redeemed in the fourth quarter of 2010.

*2016 Senior Notes.* In July and October 2006, the Issuers completed a private placement, subsequently registered, of $275 million in aggregate principal amount of 8.5% senior unsecured notes due 2016 ("2016 Senior Notes") to qualified institutional buyers. The 2016 Senior Notes were redeemed in the first and third quarters of 2011.

*2018 Senior Notes.* In April 2008, the Issuers completed a private placement, subsequently registered, of $400 million in aggregate principal amount of 8.75% senior unsecured notes to qualified institutional buyers under Rule 144A. In May 2008, the Partnership completed the placement of an additional $100 million pursuant to the indenture to the 2018 Senior Notes. The notes issued in the April 2008 and May 2008 offerings are treated a single class of debt under this same indenture. Approximately $253.3 million and $165.6 million of the 2018 Senior Notes were redeemed in the fourth quarter and first quarter of 2011, respectfully. The remaining 2018 Senior Notes mature on April 15, 2018, and interest is payable semi-annually in arrears on April 15 and October 15. The Partnership received combined proceeds of approximately $488.5 million, after including initial purchasers' premium and deducting the underwriting fees and the other expenses of the offering.

*2020 Senior Notes.* In November 2010, the Issuers completed a public offering of $500 million in aggregate principal amount of 6.75% senior unsecured notes. The 2020 Senior Notes mature on November 1, 2020, and interest is payable semi-annually in arrears on May 1 and November 1. The Partnership received proceeds of approximately $490.3 million after deducting the underwriting fees and the other third-party expenses associated with the offering.

*2021 Senior Notes.* On February 24, 2011, the Issuers completed a public offering of $300 million in aggregate principal amount of 6.5% senior unsecured notes, which were issued at par. On March 10, 2011, the Issuers completed a follow-on public offering of an additional $200 million in aggregate principal amount of 2021 Senior Notes, which were issued at 99.5% of par and are treated as a single class of debt securities under the same indenture as the 2021 Senior Notes issued on February 24, 2011. The 2021 Senior Notes mature on August 15, 2021, and interest is payable semi-annually in arrears on February 15 and August 15. The Partnership received aggregate net proceeds of approximately $492 million from the 2021 Senior Notes offerings after deducting the underwriting fees and other third-party expenses associated with the offerings.

**15. Long-Term Debt (Continued)**

*2022 Senior Notes.* On November 3, 2011, the Issuers completed a public offering of $700 million in aggregate principal amount of 6.25% senior unsecured notes due June 2022. Interest on the 2022 Notes is payable semi-annually in arrears on June 15 and December 15, commencing June 15, 2012. The Partnership received aggregate net proceeds of approximately $688 million from the 2022 Senior Notes offerings, after deducting the underwriting fees and other third-party expenses.

*2023A Senior Notes.* On August 10, 2012, the Issuers completed a public offering of $750 million in aggregate principal amount of 5.5% senior unsecured notes due February 2023. Interest on the 2023A Senior Notes is payable semi-annually in arrears on February 15 and August 15, commencing February 15, 2023. The Partnership received aggregate net proceeds of approximately $730 million from the 2023A Senior Notes offerings, after deducting the underwriting fees and other third-party expenses.

The proceeds from the issuance of the 2021 and 2022 Senior Notes were used to redeem $275 million in aggregate principal amount of 2016 Senior Notes and $419 million in aggregate principal amount of 2018 Senior Notes and to provide additional working capital for general partnership purposes. The proceeds from the issuance of the 2020 Senior Notes were used to redeem the 2014 Senior Notes, repay the Credit Facility and to provide additional working capital for general partnership purposes. The proceeds from the issuance of the 2023A Senior Notes were used to fund capital expenditures and provide additional working capital for general partnership purposes.

The Partnership recorded a total pre-tax loss of approximately $79.0 million during 2011 related to the redemption of the 2016 Senior Notes and 2018 Senior Notes. The pre-tax loss consisted of approximately $7.6 million related to the non-cash write-off of the unamortized discount and deferred finance costs and approximately $71.4 million related to the payment of tender premiums and third party expenses. The loss is recorded in *Loss on redemption of debt* in the accompanying Consolidated Statements of Operations.

The Partnership recorded a total pre-tax loss of approximately $46.3 million in the fourth quarter of 2010 related to the redemption of the senior notes issued in October 2004 and May 2009. The pre-tax loss consisted of approximately $36.6 million related to the non-cash write-off of the unamortized discount and deferred finance costs and approximately $9.7 million related to the payment of premiums. The loss is recorded in *Loss on redemption of debt* in the accompanying Consolidated Statements of Operations.

The Issuers have no independent operating assets or operations. All subsidiaries that are owned 100% by the Partnership, other than MarkWest Energy Finance Corporation and MarkWest Liberty Midstream and its subsidiaries, guarantee the Senior Notes, jointly and severally and fully and unconditionally, subject to certain customary release provisions, including:

(1) in connection with any sale or other disposition of all or substantially all of a subsidiary guarantor's assets (including by way of merger or consolidation) to a third party, if the transaction does not violate the asset sale provisions of the indentures;

(2) in connection with any sale or other disposition of the equity interests of a subsidiary guarantor to a third party, if the transaction does not violate the asset sale provisions of the indentures and the subsidiary guarantor is no longer a restricted subsidiary of the Partnership;

(3) if the Partnership designates any subsidiary guarantor as an unrestricted subsidiary under the indentures;

**15. Long-Term Debt (Continued)**

(4) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indentures; and

(5) at such time as a subsidiary guarantor no longer guarantees any other indebtedness of the Issuers or MarkWest Energy Operating Company, L.L.C. ("Operating Company") and, in the case of Operating Company, Operating Company is not an obligor of any indebtedness under the Credit Facility.

Subsidiaries that are not 100% owned by the Partnership do not guarantee the Senior Notes (see Note 24 for required consolidating financial information). The Senior Notes are senior unsecured obligations equal in right of payment with all of the Partnership's existing and future senior debt. The Senior Notes are senior in right of payment to all of the Partnership's future subordinated debt but effectively junior in right of payment to its secured debt to the extent of the assets securing the debt, including the Partnership's obligations in respect of the Credit Facility.

The indentures governing the Senior Notes limit the activity of the Partnership and the restricted subsidiaries identified in the indentures. Subject to compliance with certain covenants, the Partnership may issue additional notes from time to time under the indentures. If at any time the Senior Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Rating Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate, in which case the Partnership and its subsidiaries will cease to be subject to such terminated covenants.

As of December 31, 2012, there are no minimum principal payments on Senior Notes due during the next five years. See Note 28 for long-term debt activity in 2013.

**16. Equity**

The Partnership Agreement stipulates the circumstances under which the Partnership is authorized to issue new capital, maintain capital accounts and distribute cash and contains specific provisions for the allocation of net income and losses to each of the partners for purposes of maintaining their respective partner capital accounts.

*Distributions of Available Cash*

The Partnership distributes all of its Available Cash, including the Available Cash of its subsidiaries, to all common unitholders of record within 45 days after the end of each quarter. Available Cash is generally defined as all cash and cash equivalents of the Partnership on hand at the end of each quarter, less reserves established by the general partner for future requirements, plus all cash for the quarter from working capital borrowings made after the end of the quarter. The general partner has the discretion to establish cash reserves that are necessary or appropriate to (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to unitholders and the general partner for up to the next four quarters. Class A unitholders receive distributions of Available Cash (excluding the Available Cash attributable to MarkWest Hydrocarbon). However, because all Class A unitholders are wholly-owned subsidiaries, these intercompany distributions do not impact the amount of Available Cash that can be distributed to common unitholders. Class B units are not entitled to participate in any distributions of Available Cash prior to their conversion.

**16. Equity (Continued)**

The quarterly cash distributions applicable to 2012, 2011 and 2010 were as follows:

| Quarter Ended | Distribution Per Common Unit | Declaration Date | Record Date | Payment Date |
|---|---|---|---|---|
| December 31, 2012 | $0.82 | January 23, 2013 | February 6, 2013 | February 14, 2013 |
| September 30, 2012 | $0.81 | October 25, 2012 | November 7, 2012 | November 14, 2012 |
| June 30, 2012 | $0.80 | July 26, 2012 | August 6, 2012 | August 14, 2012 |
| March 31, 2012 | $0.79 | April 26, 2012 | May 7, 2012 | May 15, 2012 |
| December 31, 2011 | $0.76 | January 26, 2012 | February 6, 2012 | February 14, 2012 |
| September 30, 2011 | $0.73 | October 18, 2011 | November 7, 2011 | November 14, 2011 |
| June 30, 2011 | $0.70 | July 21, 2011 | August 1, 2011 | August 12, 2011 |
| March 31, 2011 | $0.67 | April 21, 2011 | May 2, 2011 | May 13, 2011 |
| December 31, 2010 | $0.65 | January 27, 2011 | February 7, 2011 | February 14, 2011 |
| September 30, 2010 | $0.64 | October 27, 2010 | November 8, 2010 | November 12, 2010 |
| June 30, 2010 | $0.64 | July 22, 2010 | August 2, 2010 | August 13, 2010 |
| March 31, 2010 | $0.64 | April 22, 2010 | May 3, 2010 | May 14, 2010 |

*Equity Offerings*

The public equity offerings completed in 2012, 2011 and 2010 were as follows (in millions):

| Closing date of offering | Common units(1) | Net proceeds(2) |
|---|---|---|
| April 6, 2010 | 4.9 | $142 |
| January 14, 2011 | 3.5 | $138 |
| July 13, 2011 | 4.0 | $185 |
| October 13, 2011 | 5.8 | $251 |
| December 19, 2011 | 10.0 | $521 |
| January 13, 2012 | 0.7 | $ 38 |
| March 16, 2012 | 6.8 | $388 |
| May 14, 2012(3) | 8.0 | $427 |
| August 17, 2012 | 6.9 | $338 |
| November 19, 2012 | 9.8 | $437 |
| December 2012(4) | 0.1 | $ 6 |

(1) Includes the full exercise of the underwriters' overallotment option unless otherwise noted.

(2) Net proceeds from equity offerings were used to repay borrowings under the Credit Facility, to fund acquisitions and capital expenditures and to provide working capital for general partnership purposes.

(3) The underwriters' did not exercise their over-allotment option for this offering.

(4) In November 2012, the Partnership announced a continuous equity program which allows the Partnership from time to time, through the Manager, as its sales agent, to offer and sell common units representing limited partner interests having an aggregate offering

**16. Equity (Continued)**

price of up to $600 million. Sales of such common units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by the Manager and the Partnership. The Partnership may also sell common units to the Manager as principal for its own account at a price to be agreed upon at the time of the sale. For any such sales, the Partnership will enter into a separate agreement with the Manager.

**17. Commitments and Contingencies**

*Legal*

The Partnership is subject to a variety of risks and disputes, and is a party to various legal proceedings in the normal course of its business. The Partnership maintains insurance policies in amounts and with coverage and deductibles as it believes reasonable and prudent. However, the Partnership cannot assure that the insurance companies will promptly honor their policy obligations or that the coverage or levels of insurance will be adequate to protect the Partnership from all material expenses related to future claims for property loss or business interruption to the Partnership, or for third-party claims of personal and property damage, or that the coverages or levels of insurance it currently has will be available in the future at economical prices. While it is not possible to predict the outcome of the legal actions with certainty, management is of the opinion that appropriate provisions and accruals for potential losses associated with all legal actions have been made in the consolidated financial statements and that none of these actions, either individually or in the aggregate, will have a material adverse effect on the Partnership's financial condition, liquidity or results of operation.

*Contract Contingencies*

Certain natural gas processing arrangements in the Partnership's Liberty, Utica and Northeast segments require the Partnership to construct new natural gas processing plants and NGL pipelines and contain certain fees and charges if specified construction milestones are not achieved for reasons other than force majeure. In certain cases, certain producers may have the right to cancel the processing arrangements if there are significant delays that are not due to force majeure. As of December 31, 2012, management does not believe there are any indications that the Partnership will not be able to meet the construction milestones.

*Lease and Other Contractual Obligations*

The Partnership has various non-cancellable operating lease agreements and a long-term propane storage agreement expiring at various times through fiscal year 2040. Annual expense under these agreements was $20.8 million, $15.0 million and $18.4 million for the years ended December 31, 2012,

**17. Commitments and Contingencies (Continued)**

2011 and 2010, respectively. The minimum future payments under these agreements as of December 31, 2012 are as follows (in thousands):

| Year ending December 31, | |
|---|---|
| 2013 | 18,544 |
| 2014 | 15,994 |
| 2015 | 13,825 |
| 2016 | 13,761 |
| 2017 | 14,231 |
| 2018 and thereafter | 75,231 |
| | $151,586 |

*SMR Transaction*

On September 1, 2009, the Partnership entered into a product supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for all of the product processed by the SMR (see Note 5 for further discussion of this agreement and the related SMR Transaction). The product received under this agreement is sold to a refinery customer pursuant to a corresponding long-term agreement. The minimum amounts payable annually under the product supply agreement, excluding the potential impact of inflation adjustments per the agreement, are as follows (in thousands):

| Year ending December 31, | |
|---|---|
| 2013 | $ 17,412 |
| 2014 | 17,412 |
| 2015 | 17,412 |
| 2016 | 17,412 |
| 2017 | 17,412 |
| 2018 and thereafter | 212,617 |
| Total minimum payments | 299,677 |
| Less: Services element | 114,634 |
| Less: Interest | 93,192 |
| Total SMR liability | 91,851 |
| Less: Current portion of SMR Liability | 2,259 |
| Long-term portion of SMR Liability | $ 89,592 |

**18. Lease Operations**

Based on the terms of certain natural gas gathering, transportation, and processing agreements, the Partnership is considered to be the lessor under several implicit operating lease arrangements in accordance with GAAP. The Partnership's primary implicit lease operations relate to a natural gas gathering agreement in the Liberty segment for which it earns a fixed-fee for providing gathering services to a single producer using a dedicated gathering system. As the gathering system is expanded, the fixed-fee charged to the producer is adjusted to include the additional gathering assets in the lease.

**18. Lease Operations (Continued)**

The primary term of the natural gas gathering arrangement expires in 2024 and will continue thereafter on a year to year basis until terminated by either party. Other significant implicit leases relate to a natural gas processing agreement in the Liberty segment and a natural gas processing agreement in the Northeast segment for which the Partnership earns minimum monthly fees for providing processing services to a single producer using a dedicated processing plant. The primary term of these natural gas processing agreements expire between 2022 and 2024.

The Partnership's revenue from its implicit lease arrangements, excluding executory costs, totaled approximately $84.0 million, $67.4 million and $32.2 million for the years ended December 31, 2012, 2011 and 2010, respectively. The Partnership's implicit lease arrangements related to the processing facilities contain contingent rental provisions whereby the Partnership receives additional fees if the producer customer exceeds the monthly minimum processed volumes. During the years ended December 31, 2012 and 2011, the Partnership received approximately $15.2 million and $13.5 million in contingent lease payments, respectively. The following is a schedule of minimum future rentals on the non-cancellable operating leases as of December 31, 2012 (in thousands):

| Year ending December 31, | |
|---|---|
| 2013 | 86,516 |
| 2014 | 87,247 |
| 2015 | 84,810 |
| 2016 | 84,810 |
| 2017 | 84,810 |
| 2018 and thereafter | 447,858 |
| Total minimum future rentals | $876,051 |

The following schedule provides an analysis of the Partnership's investment in assets held for operating lease by major classes as of December 31, 2012 and 2011 (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| Natural gas gathering and NGL transportation pipelines and facilities | $ 860,576 | $479,567 |
| Construction in progress | 203,863 | 38,386 |
| Property, plant and equipment | 1,064,439 | 517,953 |
| Less: accumulated depreciation | (78,343) | (46,006) |
| Total property, plant and equipment, net | $ 986,096 | $471,947 |

## 19. Incentive Compensation Plans

The following table summarizes the share-based compensation plans administered by the Compensation Committee of the Board ("Compensation Committee") that were active during the periods presented in the accompanying Consolidated Statements of Operations:

| Share-based compensation plan | Award Classification | Further awards authorized for issuance under plan as of December 31, 2012 | Awards outstanding under the plan as of December 31, 2012 | Final Year of Activity |
|---|---|---|---|---|
| 2008 Long-Term Incentive Plan ("2008 LTIP") | Equity | Yes | Yes | N/A |
| 2006 Hydrocarbon Stock Incentive Plan ("2006 Hydrocarbon Plan") | Equity | No | No | 2010 |
| Long-Term Incentive Plan ("2002 LTIP") | Liability | No | No | 2011 |

*Compensation Expense*

Total compensation expense recorded for share-based pay arrangements was as follows (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Phantom units | $14,615 | $13,479 | $15,319 |
| Distribution equivalent rights(1) | 41 | 446 | 1,465 |
| Total compensation expense | $14,656 | $13,925 | $16,784 |

(1) A distribution equivalent right is a right, granted in tandem with a specific phantom unit, to receive an amount in cash equal to, and at the same time as, the cash distributions made by the Partnership with respect to a unit during the period such phantom unit is outstanding. Payment of distribution equivalent rights associated with units that are expected to vest are recorded as capital distributions, however, payments associated with units that are not expected to vest are recorded as compensation expense.

Compensation expense under the share-based compensation plans has been recorded as either *Selling, general and administrative expenses* or *Facility expenses* in the accompanying Consolidated Statements of Operations.

As of December 31, 2012, total compensation expense not yet recognized related to the unvested awards under the 2008 LTIP was approximately $12.7 million, with a weighted average remaining vesting period of approximately 1.0 years.

*2008 LTIP*

The 2008 LTIP was approved by unitholders on February 21, 2008. The 2008 LTIP provides 3.7 million common units for issuance to the Corporation's employees and affiliates as share-based payment awards. The 2008 LTIP was created to attract and retain highly qualified officers, directors, and other key individuals and to motivate them to serve the General Partner, the Partnership and their affiliates and to expend maximum effort to improve the business results and earnings of the Partnership

**19. Incentive Compensation Plans (Continued)**

and its affiliates. Awards authorized under the 2008 LTIP include unrestricted units, restricted units, phantom units, distribution equivalent rights, and performance awards to be granted in any combination.

*TSR Performance Units.* In April 2010, the Board granted 282,000 TSR Performance Units under the 2008 LTIP to senior executives and other key employees. The TSR Performance Units are classified as equity awards and do not contain distribution equivalent rights. The TSR Performance Units vested in equal installments on January 31, 2011 and January 31, 2012, based on the Partnership's relative total unitholder return (unit price appreciation and distribution performance) over the three-year calendar period prior to the scheduled vesting date compared to the total unitholder return of a defined group of peer companies over the same period ("Market Criteria"). In January 2011 and 2012, 141,000 TSR Performance Units vested based on the Market Criteria and the Board exercised its discretion to issue and immediately vest an additional 35,250 units.

Compensation expense related to the TSR Performance Units that vested solely based on the Market Criteria was recognized over the requisite service period based on the fair value of the units as of the grant date. However, a grant date, as defined by GAAP, was not established for the TSR Performance Units that vest based on a combination of the Market Criteria and performance criteria until the Board exercised its discretion because the performance criteria prevents a mutual understanding of the key terms of the award. Therefore, compensation expense related to this portion of the TSR Performance Units was recognized over the requisite service period based on the fair value of the units as of each reporting date. The requisite service period for all TSR Performance Units began in April 2010 when the Board approved the awards. TSR Compensation expense recognized related to TSR Performance Units was approximately $2.2 million, $4.8 million and $4.5 million for the years ended December 31, 2012, 2011 and 2010, respectively.

The fair value of the TSR Performance Units was measured at each appropriate measurement date using a Monte Carlo simulation model that estimated the most likely outcome based on the terms of the award. The key inputs in the model include the market price of the Partnership's common units as of the valuation date, the historical volatility of the market price of the Partnership's common units, the historical volatility of the market price of the common units or common stock of the peer companies, and the correlation between changes in the market price of the Partnership's common units and those of the peer companies.

*Unrestricted Units.* In January 2010, the Board granted 166,000 unrestricted units to senior executives and other key employees under the 2008 LTIP. The unrestricted units vested immediately and the Partnership recognized approximately $4.8 million of expense related to these units.

*Performance Units.* Phantom units containing performance vesting criteria ("Performance Units") were granted to senior executives and other key employees under the 2008 LTIP in 2008 and 2009. The Performance Units were scheduled to vest on a performance-based schedule over a three-year period based on the Partnership achieving established financial performance goals determined by the Compensation Committee. In January 2012, it was determined that the performance goals were not met and all Performance Units were forfeited. Compensation expense recorded for the Performance Units was zero for the years ended December 31, 2012, 2011 and 2010.

**19. Incentive Compensation Plans (Continued)**

*2006 Hydrocarbon Plan*

On February 21, 2008, outstanding shares of restricted stock granted under the 2006 Hydrocarbon Plan were converted to phantom units in connection with the Merger. The converted phantom unit awards remained outstanding under the terms of the 2006 Hydrocarbon Plan until their respective settlement dates. The last converted phantom units outstanding under the 2006 Hydrocarbon Plan vested on January 31, 2010.

*Summary of Equity Awards*

Awards under the 2008 LTIP, and historically the 2006 Hydrocarbon Plan, qualify as equity awards. Accordingly, the fair value is measured at the grant date using the market price of the Partnership's common units. A phantom unit entitles an employee to receive a common unit upon vesting. The Partnership generally issues new common units upon vesting of phantom units. Phantom unit awards generally vest in equal tranches over a three-year period, or cliff vest after three years. For service-based awards, compensation expense related to each tranche is recognized over its requisite service period, reduced for an estimate of expected forfeitures. Compensation expense related to performance-based awards is recognized when probability of vesting is established. As part of a net settlement option, employees may elect to surrender a certain number of phantom units, and in exchange, the Partnership assumes the income tax withholding obligations related to the vesting. Phantom units surrendered for the payment of income tax withholdings will again become available for issuance under the plan from which the awards were initially granted, provided that further awards are authorized for issuance under the plan. The Partnership was required to pay approximately $8.1 million, $6.0 million and $3.4 million during the years ended December 31, 2012, 2011 and 2010, respectively, for income tax withholdings related to the vesting of equity awards. The Partnership received no proceeds from the issuance of phantom units, and none of the phantom units that vested were redeemed by the Partnership for cash.

The following is a summary of all phantom unit activity under the 2008 LTIP and 2006 Hydrocarbon Plan for the year ended December 31, 2012:

| | Number of Units | Weighted-average Grant-date Fair Value |
|---|---|---|
| Unvested at December 31, 2011 (includes 141,000 TSR Performance units) | 935,509 | 28.59 |
| Granted (includes 35,250 TSR Performance units) | 296,545 | 57.50 |
| Vested (includes 176,250 TSR Performance units) | (386,334) | 26.98 |
| Forfeited | (158,144) | 11.95 |
| Unvested at December 31, 2012 | 687,576 | 45.79 |

The total fair value and intrinsic value of the phantom units vested under the 2008 LTIP was $10.4 million, $10.7 million and $9.8 million during the years ended December 31, 2012, 2011, and 2010, respectively. The total fair value and intrinsic value of the TSR Performance Units vested during the years ended December 31, 2012 and 2011 was $6.5 million and $4.9 million, respectively.

**19. Incentive Compensation Plans (Continued)**

*2002 LTIP*

The phantom units awarded under the 2002 LTIP are classified as liability awards. Accordingly, the fair value of the outstanding awards is re-measured at the end of each reporting period using the market price of the Partnership's common units. The fair value of the phantom units awarded is amortized into earnings as compensation expense over the vesting period, which is generally three years. A phantom unit entitles an employee to receive a common unit upon vesting, or at the discretion of the Compensation Committee, the cash equivalent to the value of a common unit. The Partnership generally issues new common units upon the vesting of phantom units. As part of a net settlement option, employees may elect to surrender a certain number of phantom units, and in exchange, the Partnership assumes the income tax withholding obligations related to the vesting. The Partnership received no proceeds for issuing phantom units and none of the phantom units that vested were redeemed by the Partnership for cash. The amounts paid by the Partnership for income tax withholdings related to the vesting of awards under the 2002 LTIP were $0.4 million and $0.4 million for the years ended December 31, 2011 and 2010, respectively. The total fair value and intrinsic value of the phantom units vested under the 2002 LTIP was $1.0 million and $1.3 million during the years ended December 31, 2011, and 2010, respectively.

*Tax effects of share-based compensation*

The Partnership elected to adopt the simplified method to establish the beginning balance of the additional paid-in capital pool ("APIC Pool") related to the tax effects of employee share-based compensation, and to determine the subsequent impact on the APIC Pool and Consolidated Statements of Cash Flows of the tax effects of share-based compensation awards that were outstanding upon adoption. Additional paid-in capital is reported as *Common units* in the accompanying Consolidated Balance Sheets. Cash flows resulting from tax deductions in excess of the cumulative compensation cost recognized for share-based compensation awards exercised are classified as financing cash flows and are included as *Excess tax benefits related to share-based compensation* in the accompanying Consolidated Statements of Cash Flows.

**20. Employee Benefit Plan**

All employees dedicated to, or otherwise principally supporting the Partnership are employees of MarkWest Hydrocarbon, and substantially all of these employees are participants in MarkWest Hydrocarbon's defined contribution benefit plan. The employer matching contribution expense related to this plan was $3.2 million, $2.7 million and $2.3 million for the years ended December 31, 2012, 2011 and 2010, respectively.

## 21. Income Tax

The components of the provision for income tax expense (benefit) are as follows (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Current income tax (benefit) expense: | | | |
| Federal | $(2,964) | $15,039 | $ 5,850 |
| State | 598 | 2,539 | 1,805 |
| Total current | (2,366) | 17,578 | 7,655 |
| Deferred income tax expense (benefit): | | | |
| Federal | 38,531 | (4,732) | (3,870) |
| State | 2,163 | 803 | (596) |
| Total deferred | 40,694 | (3,929) | (4,466) |
| Provision for income tax | $38,328 | $13,649 | $ 3,189 |

A reconciliation of the provision for income tax and the amount computed by applying the federal statutory rate of 35% to the income before income taxes for the years ended December 31, 2012, 2011 and 2010 is as follows (in thousands):

**Year ended December 31, 2012:**

| | Corporation | Partnership | Eliminations | Consolidated |
|---|---|---|---|---|
| Income before provision for income tax. | $74,192 | $180,640 | $2,284 | $257,116 |
| Federal statutory rate | 35% | 0% | 0% | |
| Federal income tax at statutory rate | 25,967 | — | — | 25,967 |
| Permanent items | 28 | — | — | 28 |
| State income taxes net of federal benefit | 688 | 1,689 | — | 2,377 |
| Current year change in valuation allowance | (5) | — | — | (5) |
| Prior period adjustments and tax rate changes | (2,517) | — | — | (2,517) |
| Provision on income from Class A units(1) | 12,412 | — | — | 12,412 |
| Other | 66 | — | — | 66 |
| Provision for income tax | $36,639 | $ 1,689 | $ — | $ 38,328 |

**21. Income Tax (Continued)**

**Year ended December 31, 2011:**

| | Corporation | Partnership | Eliminations | Consolidated |
|---|---|---|---|---|
| Income before provision for income tax | $ 3,813 | $124,087 | $(8,006) | $119,894 |
| Federal statutory rate | 35% | 0% | 0% | |
| Federal income tax at statutory rate | 1,335 | — | — | 1,335 |
| Permanent items | 36 | — | — | 36 |
| State income taxes net of federal benefit | 102 | 2,742 | — | 2,844 |
| Current year change in valuation allowance | (64) | — | — | (64) |
| Prior period adjustments and tax rate changes | 163 | — | — | 163 |
| Provision on income from Class A units(1) | 9,323 | — | — | 9,323 |
| Other | 12 | — | — | 12 |
| Provision for income tax | $10,907 | $ 2,742 | $ — | $ 13,649 |

**Year ended December 31, 2010:**

| | Corporation | Partnership | Eliminations | Consolidated |
|---|---|---|---|---|
| (Loss) income before provision for income tax | $(8,120) | $47,761 | $(5,350) | $34,291 |
| Federal statutory rate | 35% | 0% | 0% | |
| Federal income tax at statutory rate | (2,842) | — | — | (2,842) |
| Permanent items | 20 | — | — | 20 |
| State income taxes net of federal benefit | (272) | 1,299 | — | 1,027 |
| Current year change in valuation allowance | (1,022) | — | — | (1,022) |
| Prior period adjustments and tax rate changes | 70 | — | — | 70 |
| Provision on income from Class A units(1) | 5,753 | — | — | 5,753 |
| Other | 183 | — | — | 183 |
| Provision for income tax | $ 1,890 | $ 1,299 | $ — | $ 3,189 |

(1) The Corporation and the General Partner own Class A units of the Partnership that were received in the merger of the Corporation and the Partnership completed in February 2008. The Class A units share, on a pro-rata basis, in income or loss of the Partnership, except for items attributable to the Partnership's ownership or sale of shares of the Corporation's common stock (as discussed in Note 2). The provision for income tax on income from Class A units includes intra period allocations to continued operations and excludes allocations to equity.

**21. Income Tax (Continued)**

The deferred tax assets and liabilities resulting from temporary book-tax differences are comprised of the following (in thousands):

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| Current deferred tax assets: | | |
| Accruals and reserves | $ 98 | $ 78 |
| Derivative instruments | 5,183 | 14,807 |
| Current deferred tax assets | 5,281 | 14,885 |
| Long-term deferred tax assets: | | |
| Accruals and reserves | 113 | 48 |
| Derivative instruments | 9,915 | 20,301 |
| Phantom unit compensation | 2,624 | 2,103 |
| Capital loss carryforward | 904 | 971 |
| State net operating loss carryforward | 1 | 101 |
| Long-term deferred tax assets | 13,557 | 23,524 |
| Valuation allowance | (904) | (977) |
| Net long-term deferred tax assets | 12,653 | 22,547 |
| Long-term deferred tax liabilities: | | |
| Property, plant and equipment and intangibles | 3,861 | 2,123 |
| Investment in affiliated groups | 200,110 | 114,088 |
| Long-term deferred tax liabilities | 203,971 | 116,211 |
| Long-term subtotal | (191,318) | (93,664) |
| Net deferred tax liability | $(186,037) | $(78,779) |

Significant judgment is required in evaluating tax positions and determining the Corporation's provision for income taxes. During the ordinary course of business, there may be transactions and calculations for which the ultimate tax determination is uncertain. However, the Corporation did not have any material uncertain tax positions for the years ended December 31, 2012, 2011 or 2010. As of December 31, 2012, the Corporation had a capital loss carryforward of approximately $0.9 million that expires in 2014. The Corporation does not anticipate utilizing this carryforward and has provided a 100% valuation allowance against this long-term deferred tax asset. While the Corporation's consolidated federal tax return and any significant state tax returns are not currently under examination, the tax years 2008 through 2011 remain open to examination by the major taxing jurisdictions to which the Corporation is subject.

## 22. Earnings (Loss) Per Common Unit

The following table shows the computation of basic and diluted net (loss) income per common unit, for the years ended December 31, 2012, 2011 and 2010, respectively, and the weighted average units used to compute diluted net (loss) income per common unit (in thousands, except per unit data):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Net income attributable to the Partnership's unitholders | $220,402 | $60,695 | $ 467 |
| Less: Income allocable to phantom units | 2,142 | 1,749 | 1,308 |
| Income (loss) available for common unitholders—basic | 218,260 | 58,946 | (841) |
| Add: Income allocable to phantom units and DER expense(1) | 2,183 | — | — |
| Income (loss) available for common unitholders—diluted | $220,443 | $58,946 | $ (841) |
| Weighted average common units outstanding—basic | 109,979 | 78,466 | 70,128 |
| Potential common units (Class B and phantom units)(1) | 20,669 | 153 | — |
| Weighted average common units outstanding—diluted | 130,648 | 78,619 | 70,128 |
| Net income (loss) attributable to the Partnership's common unitholders per common unit(2) | | | |
| Basic | $ 1.98 | $ 0.75 | $ (0.01) |
| Diluted | $ 1.69 | $ 0.75 | $ (0.01) |

(1) In 2012, the use of the if converted method is now more dilutive, therefore income allocable to phantom units and DER expense included in the calculation of diluted earnings per unit and the phantom units are included in the potential common units.

(2) For the years ended December 31, 2011 and 2010, dilutive instruments include TSR Performance Units and are based on the number of units, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For the year ended December 31, 2010, 195 units were excluded from the calculation of diluted units because the impact was anti-dilutive. See Note 19 for further discussion of TSR Performance Units.

## 23. Segment Information

The Partnership's chief operating decision maker is the chief executive officer ("CEO"). The CEO reviews the Partnership's discrete financial information on a geographic and operational basis, as the products and services are closely related within each geographic region and business operation. Accordingly, the CEO makes operating decisions, assesses financial performance and allocates resources on a geographical basis. The Partnership has the following segments: Southwest, Northeast, Liberty and Utica. For all years presented, the Southwest segment includes the operations of the Partnership's processing facilities in Corpus Christi, Texas that were reported separately in the Gulf Coast segment in prior years. The Gulf Coast operations are no longer material to the Partnership's operations and no longer meaningful separately. The Southwest segment has operations in Texas, Oklahoma, Louisiana and New Mexico. The Northeast segment has operations in Kentucky, southern West Virginia and Michigan. The Liberty segment has operations in Pennsylvania and northern West Virginia. The Utica segment has operations in Ohio. All segments provide gathering, processing,

**23. Segment Information (Continued)**

transportation and storage services. The Southwest, Northeast and Liberty segments also provide, and the Utica segment will provide, fractionation services.

The Partnership prepares segment information in accordance with GAAP. Certain items below *Income (loss) from operations* in the accompanying Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any gains (losses) from derivative instruments are not allocated to individual segments. Management does not consider these items allocable to or controllable by any individual segment and, therefore, excludes these items when evaluating segment performance. Segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

The tables below present information about operating income and capital expenditures for the reported segments for the years ended December 31, 2012, 2011 and 2010 (in thousands).

**Year ended December 31, 2012:**

| | Southwest | Northeast | Liberty | Utica | Total |
|---|---|---|---|---|---|
| Segment revenue | $856,416 | $225,818 | $ 319,867 | $ 571 | $1,402,672 |
| Purchased product costs | 387,902 | 68,402 | 74,024 | — | 530,328 |
| Net operating margin | 468,514 | 157,416 | 245,843 | 571 | 872,344 |
| Facility expenses | 124,921 | 24,106 | 65,825 | 3,968 | 218,820 |
| Portion of operating income (loss) attributable to non-controlling interests | 5,790 | — | — | (1,359) | 4,431 |
| Operating income before items not allocated to segments | $337,803 | $133,310 | $ 180,018 | $ (2,038) | $ 649,093 |
| Capital expenditures | $170,543 | $ 84,542 | $1,458,323 | $233,018 | $1,946,426 |
| Capital expenditures not allocated to segments | | | | | 5,001 |
| Total capital expenditures | | | | | $1,951,427 |

**23. Segment Information (Continued)**

**Year ended December 31, 2011:**

| | Southwest | Northeast | Liberty | Total |
|---|---|---|---|---|
| Segment revenue | $1,031,986 | $268,884 | $248,949 | $1,549,819 |
| Purchased product costs | 506,911 | 91,612 | 83,847 | 682,370 |
| Net operating margin | 525,075 | 177,272 | 165,102 | 867,449 |
| Facility expenses | 121,197 | 27,126 | 34,913 | 183,236 |
| Portion of operating income attributable to non-controlling interests | 5,431 | — | 63,731 | 69,162 |
| Operating income before items not allocated to segments | $ 398,447 | $150,146 | $ 66,458 | $ 615,051 |
| Capital expenditures | $ 106,061 | $ 51,280 | $388,850 | $ 546,191 |
| Capital expenditures not allocated to segment | | | | 5,090 |
| Total capital expenditures | | | | $ 551,281 |

**Year ended December 31, 2010:**

| | Southwest | Northeast | Liberty | Total |
|---|---|---|---|---|
| Segment revenue | $750,928 | $384,724 | $105,911 | $1,241,563 |
| Purchased product costs | 308,960 | 252,827 | 16,840 | 578,627 |
| Net operating margin | 441,968 | 131,897 | 89,071 | 662,936 |
| Facility expenses | 115,109 | 19,513 | 24,028 | 158,650 |
| Portion of operating income attributable to non-controlling interests | 6,440 | — | 26,126 | 32,566 |
| Operating income before items not allocated to segments | $320,419 | $112,384 | $ 38,917 | $ 471,720 |
| Capital expenditures | $118,056 | $ 2,179 | $332,793 | $ 453,028 |
| Capital expenditures not allocated to segments | | | | 5,640 |
| Total capital expenditures | | | | $ 458,668 |

**23. Segment Information (Continued)**

The following is a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to income before provision for income tax for the three years ended December 31, 2012, 2011 and 2010 (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Total segment revenue | $1,402,672 | $1,549,819 | $1,241,563 |
| Derivative gain (loss) not allocated to segments | 56,535 | (29,035) | (53,932) |
| Revenue deferral adjustment(1) | (7,441) | (15,385) | — |
| Total revenue | $1,451,766 | $1,505,399 | $1,187,631 |
| Operating income before items not allocated to segments | $ 649,093 | $ 615,051 | $ 471,720 |
| Portion of operating income attributable to non-controlling interests | 4,431 | 69,162 | 32,566 |
| Derivative gain (loss) not allocated to segments | 69,126 | (75,515) | (80,350) |
| Revenue deferral adjustment(1) | (7,441) | (15,385) | — |
| Compensation expense included in facility expenses not allocated to segments | (1,022) | (1,781) | (1,890) |
| Facility expenses adjustments(2) | 11,457 | 11,419 | 9,091 |
| Selling, general and administrative expenses | (94,116) | (81,229) | (75,258) |
| Depreciation | (189,549) | (149,954) | (123,198) |
| Amortization of intangible assets | (53,320) | (43,617) | (40,833) |
| Loss on disposal of property, plant and equipment | (6,254) | (8,797) | (3,149) |
| Accretion of asset retirement obligations | (677) | (1,190) | (237) |
| Income from operations | 381,728 | 318,164 | 188,462 |
| Earnings (loss) from unconsolidated affiliates | 699 | (1,095) | 1,562 |
| Interest income | 419 | 422 | 1,670 |
| Interest expense | (120,191) | (113,631) | (103,873) |
| Amortization of deferred financing costs and discount (a component of interest expense) | (5,601) | (5,114) | (10,264) |
| Derivative gain related to interest expense | — | — | 1,871 |
| Loss on redemption of debt | — | (78,996) | (46,326) |
| Miscellaneous income, net | 62 | 144 | 1,189 |
| Income before provision for income tax | $ 257,116 | $ 119,894 | $ 34,291 |

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership expects to perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and, therefore, the impact of the revenue deferrals is excluded for segment reporting purposes. For the year ended December 31, 2012, approximately $0.8 million and $6.6 million of the revenue deferral adjustment is attributable to the Southwest segment and

**23. Segment Information (Continued)**

Northeast segment, respectively. For the year ended December 31, 2011, approximately $7.2 million and $8.2 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts is expected to decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

(2) Facility expenses adjustments consist of the reallocation of the MarkWest Pioneer field services fee and the reallocation of the interest expense related to the SMR, which is included in facility expenses for the purposes of evaluating the performance of the Southwest segment.

The tables below present information about segment assets as of December 31, 2012, 2011 and 2010 (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Southwest | $2,225,838 | $2,254,962 | $2,220,063 |
| Northeast | 578,122 | 533,591 | 244,219 |
| Liberty | 3,172,144 | 1,114,654 | 743,943 |
| Utica | 439,987 | — | — |
| Total segment assets | 6,416,091 | 3,903,207 | 3,208,225 |
| Assets not allocated to segments: | | | |
| Certain cash and cash equivalents | 261,473 | 66,212 | 49,776 |
| Fair value of derivatives | 30,382 | 24,790 | 4,762 |
| Investment in unconsolidated affiliate | 31,179 | 27,853 | 28,688 |
| Other(1) | 96,591 | 48,363 | 41,911 |
| Total assets | $6,835,716 | $4,070,425 | $3,333,362 |

(1) As of December 31, 2012, 2011 and 2010, includes corporate fixed assets, deferred financing costs, income tax receivable, receivables and other corporate assets not allocated to segments.

**24. Supplemental Condensed Consolidating Financial Information**

MarkWest Energy Partners has no significant operations independent of its subsidiaries. As of December 31, 2012, the Partnership's obligations under the outstanding Senior Notes (see Note 15) were fully, jointly and severally guaranteed, by all of the subsidiaries that are owned 100% by the Partnership, other than MarkWest Liberty Midstream and its subsidiaries. The guarantees are unconditional except for certain customary circumstances in which a subsidiary would be released from the guarantee under the indentures (see Note 15 for these circumstances). Subsidiaries that are not 100% owned by the Partnership do not guarantee the Senior Notes. For the purpose of the following financial information, the Partnership's investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented in accordance with the equity method of accounting. The operations, cash flows and financial position of the co-issuer, MarkWest Energy Finance Corporation, are not material and, therefore, have been included with the Parent's financial information. Condensed consolidating financial information for MarkWest Energy Partners and its combined guarantor and

## 24. Supplemental Condensed Consolidating Financial Information (Continued)

combined non-guarantor subsidiaries as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 is as follows (in thousands):

### Condensed Consolidating Balance Sheets

| | As of December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| **ASSETS** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 210,015 | $ 102,979 | $ 34,905 | $ — | $ 347,899 |
| Restricted cash | — | — | 25,500 | — | 25,500 |
| Receivables and other current assets | 9,191 | 178,517 | 76,028 | — | 263,736 |
| Intercompany receivables | 812,562 | 18,868 | 32,656 | (864,086) | — |
| Fair value of derivative instruments | — | 18,389 | 1,115 | — | 19,504 |
| Total current assets | 1,031,768 | 318,753 | 170,204 | (864,086) | 656,639 |
| Total property, plant and equipment, net | 3,542 | 1,999,474 | 3,168,131 | (95,519) | 5,075,628 |
| Other long-term assets: | | | | | |
| Restricted cash | — | — | 10,000 | — | 10,000 |
| Investment in unconsolidated affiliate | — | 31,179 | — | — | 31,179 |
| Investment in consolidated affiliates | 4,141,782 | 2,790,994 | — | (6,932,776) | — |
| Intangibles, net of accumulated amortization | — | 559,320 | 295,835 | — | 855,155 |
| Fair value of derivative instruments | — | 10,878 | — | — | 10,878 |
| Intercompany notes receivable | 225,000 | — | — | (225,000) | — |
| Other long-term assets | 50,866 | 70,009 | 75,362 | — | 196,237 |
| Total assets | $5,452,958 | $5,780,607 | $3,719,532 | $(8,117,381) | $6,835,716 |
| **LIABILITIES AND EQUITY** | | | | | |
| Current liabilities: | | | | | |
| Intercompany payables | $ 461 | $ 839,543 | $ 24,082 | $ (864,086) | $ — |
| Fair value of derivative instruments | — | 27,062 | 167 | — | 27,229 |
| Other current liabilities | 42,301 | 197,934 | 473,654 | (1,892) | 711,997 |
| Total current liabilities | 42,762 | 1,064,539 | 497,903 | (865,978) | 739,226 |
| Deferred income taxes | 2,906 | 188,412 | — | — | 191,318 |
| Long-term intercompany financing payable | — | 225,000 | 99,592 | (324,592) | — |
| Fair value of derivative instruments | — | 32,190 | — | — | 32,190 |
| Long-term debt, net of discounts | 2,523,051 | — | — | — | 2,523,051 |
| Other long-term liabilities | 2,959 | 128,684 | 2,697 | — | 134,340 |
| Equity: | | | | | |
| Common Units | 2,128,749 | 4,141,782 | 3,119,340 | (7,255,157) | 2,134,714 |
| Class B Units | 752,531 | — | — | — | 752,531 |
| Non-controlling interest in consolidated subsidiaries | — | — | — | 328,346 | 328,346 |
| Total equity | 2,881,280 | 4,141,782 | 3,119,340 | (6,926,811) | 3,215,591 |
| Total liabilities and equity | $5,452,958 | $5,780,607 | $3,719,532 | $(8,117,381) | $6,835,716 |

## 24. Supplemental Condensed Consolidating Financial Information (Continued)

| | As of December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| **ASSETS** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 22 | $ 99,580 | $ 17,414 | $ — | $ 117,016 |
| Restricted cash | — | — | 26,193 | — | 26,193 |
| Receivables and other current assets | 7,097 | 232,010 | 55,098 | (5) | 294,200 |
| Intercompany receivables | 19,981 | 40,519 | 22,193 | (82,693) | — |
| Fair value of derivative instruments | — | 8,015 | 683 | — | 8,698 |
| Total current assets | 27,100 | 380,124 | 121,581 | (82,698) | 446,107 |
| Total property, plant and equipment, net | 4,012 | 1,714,857 | 1,163,226 | (17,788) | 2,864,307 |
| Other long-term assets: | | | | | |
| Investment in unconsolidated affiliate | — | 27,853 | — | — | 27,853 |
| Investment in consolidated affiliates | 3,071,124 | 1,097,350 | — | (4,168,474) | — |
| Intangibles, net of accumulated amortization | — | 603,224 | 543 | — | 603,767 |
| Fair value of derivative instruments | — | 16,092 | — | — | 16,092 |
| Intercompany notes receivable | 235,700 | — | — | (235,700) | — |
| Other long-term assets | 41,492 | 70,434 | 373 | — | 112,299 |
| Total assets(1) | $3,379,428 | $3,909,934 | $1,285,723 | $(4,504,660) | $4,070,425 |
| **LIABILITIES AND EQUITY** | | | | | |
| Current liabilities: | | | | | |
| Intercompany payables | $ 40,503 | $ 40,374 | $ 1,816 | $ (82,693) | $ — |
| Fair value of derivative instruments | — | 90,551 | — | — | 90,551 |
| Other current liabilities | 38,775 | 219,622 | 92,930 | (5) | 351,322 |
| Total current liabilities | 79,278 | 350,547 | 94,746 | (82,698) | 441,873 |
| Deferred income taxes | 1,228 | 92,436 | — | — | 93,664 |
| Long-term intercompany financing payable | — | 212,700 | 23,000 | (235,700) | — |
| Fair value of derivative instruments | — | 65,403 | — | — | 65,403 |
| Long-term debt, net of discounts | 1,846,062 | — | — | — | 1,846,062 |
| Other long-term liabilities | 3,232 | 117,724 | 400 | — | 121,356 |
| Equity: | | | | | |
| Common Units | 697,097 | 3,071,124 | 1,167,577 | (4,256,489) | 679,309 |
| Class B Units | 752,531 | — | — | — | 752,531 |
| Non-controlling interest in consolidated subsidiaries | — | — | — | 70,227 | 70,227 |
| Total equity | 1,449,628 | 3,071,124 | 1,167,577 | (4,186,262) | 1,502,067 |
| Total liabilities and equity | $3,379,428 | $3,909,934 | $1,285,723 | $(4,504,660) | $4,070,425 |

## 24. Supplemental Condensed Consolidating Financial Information (Continued)

### Condensed Consolidating Statements of Operations

| | Year ended December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Total revenue | $ — | $1,125,368 | $338,196 | $ (11,798) | $1,451,766 |
| Operating expenses: | | | | | |
| Purchased product costs | — | 441,853 | 74,513 | — | 516,366 |
| Facility expenses | — | 137,261 | 73,367 | (872) | 209,756 |
| Selling, general and administrative expenses | 48,949 | 19,069 | 31,147 | (5,049) | 94,116 |
| Depreciation and amortization | 607 | 164,858 | 81,898 | (4,494) | 242,869 |
| Other operating expenses | 2 | 4,341 | 2,588 | — | 6,931 |
| Total operating expenses | 49,558 | 767,382 | 263,513 | (10,415) | 1,070,038 |
| (Loss) income from operations | (49,558) | 357,986 | 74,683 | (1,383) | 381,728 |
| Earnings from consolidated affiliates | 366,460 | 67,743 | — | (434,203) | — |
| Other expense, net | (118,563) | (22,630) | (8,554) | 25,135 | (124,612) |
| Income before provision for income tax | 198,339 | 403,099 | 66,129 | (410,451) | 257,116 |
| Provision for income tax expense | 1,689 | 36,639 | — | — | 38,328 |
| Net income | 196,650 | 366,460 | 66,129 | (410,451) | 218,788 |
| Net income attributable to non-controlling interest | — | — | — | 1,614 | 1,614 |
| Net income attributable to the Partnership's unitholders | $ 196,650 | $ 366,460 | $ 66,129 | $(408,837) | $ 220,402 |

**24. Supplemental Condensed Consolidating Financial Information (Continued)**

| | Year ended December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Total revenue | $ — | $1,240,004 | $265,395 | $ — | $1,505,399 |
| Operating expenses: | | | | | |
| Purchased product costs | — | 651,132 | 84,198 | — | 735,330 |
| Facility expenses | — | 128,612 | 39,171 | (665) | 167,118 |
| Selling, general and administrative expenses | 46,903 | 31,015 | 9,011 | (5,700) | 81,229 |
| Depreciation and amortization | 719 | 151,362 | 42,198 | (708) | 193,571 |
| Other operating expenses | 673 | 9,030 | 284 | — | 9,987 |
| Total operating expenses | 48,295 | 971,151 | 174,862 | (7,073) | 1,187,235 |
| (Loss) income from operations | (48,295) | 268,853 | 90,533 | 7,073 | 318,164 |
| Earnings from consolidated affiliates | 288,870 | 44,425 | — | (333,295) | — |
| Loss on redemption of debt | (78,996) | — | — | — | (78,996) |
| Other expense, net | (91,612) | (13,501) | (558) | (13,603) | (119,274) |
| Income before provision for income tax | 69,967 | 299,777 | 89,975 | (339,825) | 119,894 |
| Provision for income tax expense | 2,742 | 10,907 | — | — | 13,649 |
| Net income | 67,225 | 288,870 | 89,975 | (339,825) | 106,245 |
| Net income attributable to non-controlling interest | — | — | — | (45,550) | (45,550) |
| Net income attributable to the Partnership's unitholders | $ 67,225 | $ 288,870 | $ 89,975 | $(385,375) | $ 60,695 |

**24. Supplemental Condensed Consolidating Financial Information (Continued)**

| | Year ended December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Total revenue | $ — | $1,063,621 | $124,010 | $ — | $1,187,631 |
| Operating expenses: | | | | | |
| Purchased product costs | — | 589,403 | 16,937 | — | 606,340 |
| Facility expenses | — | 122,240 | 28,566 | (652) | 150,154 |
| Selling, general and administrative expenses | 46,549 | 27,339 | 6,317 | (4,947) | 75,258 |
| Depreciation and amortization | 594 | 136,781 | 27,054 | (398) | 164,031 |
| Other operating expenses | 753 | 2,342 | 291 | — | 3,386 |
| Total operating expenses | 47,896 | 878,105 | 79,165 | (5,997) | 999,169 |
| (Loss) income from operations | (47,896) | 185,516 | 44,845 | 5,997 | 188,462 |
| Earnings from consolidated affiliates | 183,557 | 15,963 | — | (199,520) | — |
| Loss on redemption of debt | (46,326) | — | — | — | (46,326) |
| Other (expense) income, net | (82,000) | (16,032) | 1,753 | (11,566) | (107,845) |
| Income before provision for income tax | 7,335 | 185,447 | 46,598 | (205,089) | 34,291 |
| Provision for income tax expense | 1,299 | 1,890 | — | — | 3,189 |
| Net income | 6,036 | 183,557 | 46,598 | (205,089) | 31,102 |
| Net income attributable to non-controlling interest | — | — | — | (30,635) | (30,635) |
| Net income attributable to the Partnership's unitholders | $ 6,036 | $ 183,557 | $ 46,598 | $(235,724) | $ 467 |

## 24. Supplemental Condensed Consolidating Financial Information (Continued)

### Condensed Consolidating Statements of Cash Flows

| | Year ended December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Net cash (used in) provided by operating activities | $ (154,328) | $ 462,855 | $ 168,928 | $ 19,258 | $ 496,713 |
| Cash flows from investing activities: | | | | | |
| Restricted cash | — | — | (9,497) | — | (9,497) |
| Capital expenditures | (138) | (304,190) | (1,627,912) | (19,187) | (1,951,427) |
| Equity investments | (55,283) | (1,880,279) | — | 1,935,562 | — |
| Acquisition of business, net of cash acquired | — | — | (506,797) | — | (506,797) |
| Investment in unconsolidated affiliates | — | (5,227) | — | — | (5,227) |
| Distributions from consolidated affiliates | 75,431 | 146,178 | — | (221,609) | — |
| Investment in intercompany notes, net | (12,300) | — | — | 12,300 | — |
| Proceeds from disposal of property, plant and equipment | — | 1,732 | 77 | (1,213) | 596 |
| Net cash flows provided by (used in) investing activities | 7,710 | (2,041,786) | (2,144,129) | 1,705,853 | (2,472,352) |
| Cash flows from financing activities: | | | | | |
| Proceeds from public equity offerings, net | 1,634,081 | — | — | — | 1,634,081 |
| Proceeds from Credit Facility | 511,100 | — | — | — | 511,100 |
| Payments of Credit Facility | (577,100) | — | — | — | (577,100) |
| Proceeds from long-term debt | 742,613 | — | — | — | 742,613 |
| Proceeds (payments) related to intercompany financing, net | — | 12,300 | (1,142) | (11,158) | — |
| Payments for debt issue costs and deferred financing costs | (14,720) | — | — | — | (14,720) |
| Contributions from parent and affiliates | — | 55,283 | 1,880,279 | (1,935,562) | — |
| Contribution from non-controlling interest | — | — | 265,620 | — | 265,620 |
| Share-based payment activity | (8,067) | 907 | — | — | (7,160) |
| Payment of distributions | (339,967) | (75,431) | (152,065) | 221,609 | (345,854) |
| Payments of SMR liability | — | (2,058) | — | — | (2,058) |
| Intercompany advances, net | (1,591,329) | 1,591,329 | — | — | — |
| Net cash flows provided by financing activities | 356,611 | 1,582,330 | 1,992,692 | (1,725,111) | 2,206,522 |
| Net increase in cash | 209,993 | 3,399 | 17,491 | — | 230,883 |
| Cash and cash equivalents at beginning of year | 22 | 99,580 | 17,414 | — | 117,016 |
| Cash and cash equivalents at end of period | $ 210,015 | $ 102,979 | $ 34,905 | $ — | $ 347,899 |

## 24. Supplemental Condensed Consolidating Financial Information (Continued)

| | Year ended December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Net cash (used in) provided by operating activities | $ (126,782) | $ 410,762 | $ 137,961 | $ (7,243) | $ 414,698 |
| Cash flows from investing activities: | | | | | |
| Restricted cash | — | — | 2,006 | — | 2,006 |
| Capital expenditures | (789) | (162,517) | (399,992) | 12,017 | (551,281) |
| Acquisition of business | — | (230,728) | — | — | (230,728) |
| Equity investments | (47,295) | (252,367) | — | 299,662 | — |
| Distributions from consolidated affiliates | 50,718 | 68,651 | — | (119,369) | — |
| Investment in intercompany notes, net | (37,990) | — | — | 37,990 | — |
| Proceeds from disposal of property, plant and equipment | — | 606 | 7,617 | (4,773) | 3,450 |
| Net cash flows used in investing activities | (35,356) | (576,355) | (390,369) | 225,527 | (776,553) |
| Cash flows from financing activities: | | | | | |
| Proceeds from Credit Facility | 1,182,200 | — | — | — | 1,182,200 |
| Payments of Credit Facility | (1,116,200) | — | — | — | (1,116,200) |
| Proceeds from long-term debt | 1,199,000 | — | — | — | 1,199,000 |
| Payments of long-term debt | (693,888) | — | — | — | (693,888) |
| Payments of premiums on redemption of long-term debt | (71,377) | — | — | — | (71,377) |
| Proceeds related to intercompany financing, net | — | 14,990 | 23,000 | (37,990) | — |
| Payments for debt issuance costs, deferred financing costs and registration costs | (20,163) | — | — | — | (20,163) |
| Acquisition of non-controlling interest, including transaction costs | (997,601) | — | — | — | (997,601) |
| Contributions from parent and affiliates | — | 47,295 | 252,367 | (299,662) | — |
| Contributions from non-controlling interest | — | — | 126,392 | — | 126,392 |
| Payments of SMR Liability | — | (1,875) | — | — | (1,875) |
| Proceeds from public equity offerings, net | 1,095,488 | — | — | — | 1,095,488 |
| Share-based payment activity | (6,354) | 1,084 | — | — | (5,270) |
| Payment of distributions | (218,398) | (50,718) | (135,537) | 119,368 | (285,285) |
| Intercompany advances, net | (190,547) | 190,547 | — | — | — |
| Net cash flows provided by financing activities | 162,160 | 201,323 | 266,222 | (218,284) | 411,421 |
| Net increase in cash | 22 | 35,730 | 13,814 | — | 49,566 |
| Cash and cash equivalents at beginning of year | — | 63,850 | 3,600 | — | 67,450 |
| Cash and cash equivalents at end of period | $ 22 | $ 99,580 | $ 17,414 | $ — | $ 117,016 |

## 24. Supplemental Condensed Consolidating Financial Information (Continued)

| | Year ended December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Net cash (used in) provided by operating activities | $(102,042) | $ 373,483 | $ 46,852 | $ (5,965) | $ 312,328 |
| Cash flows from investing activities: | | | | | |
| Restricted cash | — | — | (28,001) | — | (28,001) |
| Capital expenditures | (1,924) | (123,005) | (347,231) | 13,492 | (458,668) |
| Equity investments | (44,346) | (171,252) | — | 215,598 | — |
| Distributions from consolidated affiliates | 41,167 | 22,246 | — | (63,413) | — |
| Collection of intercompany notes, net | 12,350 | — | — | (12,350) | — |
| Proceeds from disposal of property, plant and equipment | — | 733 | 7,527 | (7,527) | 733 |
| Net cash flows provided by (used in) investing activities | 7,247 | (271,278) | (367,705) | 145,800 | (485,936) |
| Cash flows from financing activities: | | | | | |
| Proceeds from Credit Facility | 494,404 | — | — | — | 494,404 |
| Payments of Credit Facility | (553,704) | — | — | — | (553,704) |
| Proceeds from long-term debt | 500,000 | — | — | — | 500,000 |
| Payments of long-term debt | (375,000) | — | — | — | (375,000) |
| Payments of premiums on redemption of long-term debt | (9,732) | — | — | — | (9,732) |
| Payments related to intercompany financing, net | — | (12,350) | — | 12,350 | — |
| Payments for debt issuance costs, deferred financing costs and registration costs | (20,912) | — | — | — | (20,912) |
| Contributions from parents and affiliates | — | 44,346 | 171,252 | (215,598) | — |
| Contributions from non-controlling interest | — | — | 158,293 | — | 158,293 |
| Payments of SMR Liability | — | (1,354) | — | — | (1,354) |
| Proceeds from public equity offering, net | 142,255 | — | — | — | 142,255 |
| Share-based payment activity | (3,834) | 98 | — | — | (3,736) |
| Payment of distributions | (181,058) | (41,167) | (28,396) | 63,413 | (187,208) |
| Intercompany advances, net | 102,376 | (102,376) | — | — | — |
| Net cash flows provided by (used in) financing activities | 94,795 | (112,803) | 301,149 | (139,835) | 143,306 |
| Net decrease in cash | — | (10,598) | (19,704) | — | (30,302) |
| Cash and cash equivalents at beginning of year | — | 74,448 | 23,304 | — | 97,752 |
| Cash and cash equivalents at end of period | $ — | $ 63,850 | $ 3,600 | $ — | $ 67,450 |

## 25. Supplemental Cash Flow Information

The following table provides information regarding supplemental cash flow information (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Supplemental disclosures of cash flow information:** | | | |
| Cash paid for interest, net of amounts capitalized | $109,001 | $112,780 | $101,459 |
| Cash paid for income taxes, net of refunds | 17,940 | 10,115 | 8,683 |
| **Supplemental schedule of non-cash investing and financing activities:** | | | |
| Accrued property, plant and equipment | $408,557 | $ 87,098 | $ 65,908 |
| Interest capitalized on construction in progress | 26,061 | 1,121 | 2,766 |
| Issuance of common units for vesting of share-based payment awards | 2,510 | 5,412 | 7,238 |
| Issuance of Class B units for acquisition of non-controlling interest | — | 752,531 | — |

## 26. Valuation and Qualifying Accounts

Activity in the Partnership's allowance for doubtful accounts and deferred tax asset valuation allowance is as follows (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| *Allowance for Doubtful Accounts* | | | |
| Balance at beginning of period | $160 | $ 162 | $ 162 |
| Charged to costs and expenses | — | — | 134 |
| Other charges(1) | (1) | (2) | (134) |
| Balance at end of period | $159 | $ 160 | $ 162 |
| *Deferred Tax Asset Valuation Allowance* | | | |
| Balance at beginning of period | $977 | $1,036 | $1,688 |
| Charged to costs and expenses | (73) | (59) | (652) |
| Balance at end of period | $904 | $ 977 | $1,036 |

(1) Bad debts written-off (net of recoveries).

## 27. Quarterly Results of Operations (Unaudited)

The following summarizes the Partnership's quarterly results of operations for 2012 and 2011 (in thousands, except per unit data):

| | Three months ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| **2012** | | | | |
| Total revenue | $350,466 | $446,053 | $283,737 | $371,510 |
| Income from operations | 51,439 | 258,902 | 9,562 | 61,825 |
| Net income (loss) | 16,273 | 187,136 | (14,756) | 30,135 |
| Net income (loss) attributable to the Partnership's unitholders | 16,020 | 186,908 | (14,340) | 31,814 |
| Net income (loss) attributable to the Partnership's common unitholders per common unit(3): | | | | |
| Basic | $ 0.16 | $ 1.74 | $ (0.13) | $ 0.26 |
| Diluted | $ 0.14 | $ 1.47 | $ (0.13) | $ 0.22 |

| | Three months ended | | | |
|---|---|---|---|---|
| | March 31(1) | June 30 | September 30 | December 31(2) |
| **2011** | | | | |
| Total revenue | $263,221 | $400,439 | $507,826 | $333,913 |
| (Loss) income from operations | (15,294) | 133,214 | 207,801 | (7,557) |
| Net (loss) income | (74,671) | 89,205 | 153,454 | (61,743) |
| Net (loss) income attributable to the Partnership's unitholders | (84,029) | 78,497 | 140,312 | (74,085) |
| Net (loss) income attributable to the Partnership's common unitholders per common unit(3): | | | | |
| Basic | $ (1.13) | $ 1.03 | $ 1.77 | $ (0.87) |
| Diluted | $ (1.13) | $ 1.03 | $ 1.77 | $ (0.87) |

(1) During the first quarter of 2011, the Partnership recorded a loss on redemption of debt of approximately $43.3 million related to the repurchase of the 2016 Senior Notes and a portion of 2018 Senior Notes. See Note 15 for further details.

(2) During the fourth quarter of 2011, the Partnership recorded a loss on redemption of debt of approximately $35.5 million related to the repurchase of a portion of the 2018 Senior Notes. See Note 15 for further details.

(3) Basic and diluted net (loss) income per unit are computed independently for each of the quarters presented; therefore, the sum of the quarterly earnings per unit may not equal the total computed for the year.

## 28. Subsequent Events

In January 2013, the Issuers completed a public offering for $1 billion in aggregate principal amount of 4.5% senior unsecured notes due in July 2023. The Partnership received net proceeds of approximately $986.9 million. A portion of the proceeds, together with cash on hand, was used to

**28. Subsequent Events (Continued)**

repurchase $81.1 million aggregate principal amount of the Partnership's 8.75% senior notes due April 2018, approximately $175 million of the outstanding principal amount of the Partnership's 6.5% senior notes due August 2021 and approximately $245 million of the outstanding principal amount of the Partnership's 6.25% senior notes due June 2022, with the remainder used to fund the Partnership's capital expenditure program and for general partnership purposes. The Partnership recorded a total pre-tax loss of approximately $38 million related to repurchases. The pre-tax loss consisted of approximately $7 million related to the non-cash write-off of the unamortized discount and deferred finance costs and approximately $31 million related to the payment of redemption premiums.

In February 2013, the Partnership and EMG Utica entered into the Amended Utica LLC Agreement for MarkWest Utica EMG which replaces the original agreements discussed in Note 4. Pursuant to the Amended Utica LLC Agreement, the aggregate funding commitment of EMG Utica has increased from $500 million to $950 million (the "Minimum EMG Investment"). As part of this commitment, EMG Utica is required to fund, as needed, all capital required for MarkWest Utica EMG until such time as EMG Utica has contributed aggregate capital equal to $750 million (the "Tier 1 EMG Contributions"). Following the funding of the Tier 1 EMG Contributions, the Partnership will have the one time right to elect to fund up to 60% of all capital required for MarkWest Utica EMG until such time as EMG Utica has contributed aggregate capital equal to the Minimum EMG Investment, and EMG Utica will be required to fund all capital not elected to be funded by the Partnership. Once EMG Utica has funded the Minimum EMG Investment, the Partnership will be required to fund, as needed, 100% of all capital for MarkWest Utica EMG until such time as the aggregate capital that has been contributed by the Partnership and EMG Utica equals $2 billion. After such time, and until such time as the investment balances of the Partnership and EMG Utica are in the ratio of 70% and 30%, respectively (such time being referred to as the "Second Equalization Date"), EMG Utica will have the right, but not the obligation, to fund up to 10% of each capital call for MarkWest Utica EMG, and the Partnership will be required to fund all remaining capital not elected to be funded by EMG Utica. After the Second Equalization Date, the Partnership and EMG Utica will have the right, but not the obligation, to fund its pro rata portion (based on the respective investment balances) of any additional required capital and may also fund additional capital which the other party elects not to fund.

Under the Amended Utica LLC Agreement, after EMG Utica has contributed more than $500 million to MarkWest Utica EMG, and prior to December 31, 2016, EMG Utica's investment balance will also be increased by a quarterly special allocation of income ("Preference Amount") that is based upon the amount of capital contributed by EMG Utica in excess of $500 million. No Preference Amount will accrue to EMG Utica's investment balance after December 31, 2016.

If the Partnership's investment balance does not equal at least 51% of the aggregate investment balances of both Members as of December 31, 2016, then EMG Utica may require that Partnership purchase membership interests from EMG Utica so that, following the purchase, the Partnership's investment balance equals 51% of the aggregate investment balances of the Members. The purchase price payable would equal the investment balance associated with the membership interests so acquired from EMG Utica. If EMG Utica makes this election, the Partnership would be required to purchase the membership interests on or prior to March 1, 2017, but effective as of January 1, 2017.

Under the Amended Utica LLC Agreement, the Partnership will continue to receive 60% of cash generated by MarkWest Utica EMG that is available for distribution until the earlier of December 31,

**28. Subsequent Events (Continued)**

2016 and the date on which the Partnership's investment balance equals 60% of the aggregate investment balances of the Partnership and EMG Utica. After the earlier to occur of those dates, cash generated by MarkWest Utica EMG that is available for distribution will be allocated to the Partnership and EMG Utica in proportion to their respective investment balances.

In contemplation of executing the Amended Utica LLC Agreement, the Partnership and EMG Utica had executed an amendment to Original Agreement in January 2013 that obligated the Partnership to temporarily fund MarkWest Utica EMG while EMG Utica completed efforts to raise additional capital to fund its remaining $150 million capital commitment under the Original Agreement. In February 2013, the Partnership contributed approximately $76.2 million to MarkWest Utica EMG and subsequently received a distribution of $61.2 million as reimbursement for the temporary funding. The remaining $15 million will be retained by MarkWest Utica EMG and treated as a capital contribution from the Partnership under the terms of the Amended Utica LLC Agreement.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors of
MarkWest Energy GP, L.L.C
Denver, Colorado

We have audited the internal control over financial reporting of MarkWest Energy Partners, L.P., and subsidiaries (the "Partnership") as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible 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 an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company'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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Partnership and our report dated February 27, 2013 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2013

## 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*

An evaluation was performed under the supervision and with the participation of the Partnership's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rule 13a-15(e) of the 1934 Act, as of December 31, 2012. Based on this evaluation, the Partnership's management, including our Chief Executive Officer and Chief Financial Officer, concluded that as of December 31, 2012, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to provide reasonable assurance that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

*Management's Report on Internal Control Over Financial Reporting*

Management of the Partnership is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) of the 1934 Act. Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2012 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As a result of this assessment, management concluded that, as of December 31, 2012, our internal control over financial reporting was effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

*Limitations on Controls*

Our disclosure controls and procedures and internal control over financial reporting are designed to provide reasonable assurance of achieving their objectives as specified above. Management does not expect, however, that our disclosure controls and procedures or our internal control over financial reporting will prevent or detect all error and fraud. Any control system, no matter how well designed and operated, is based upon certain assumptions and can provide only reasonable, not absolute, assurance that its objectives will be met. Further, no evaluation of controls can provide absolute assurance that misstatements due to error or fraud will not occur or that all control issues and instances of fraud, if any, within the Partnership have been detected.

*Changes in Internal Control Over Financial Reporting*

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2012 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Deloitte & Touche has independently assessed the effectiveness of our internal control over financial reporting and its report is included below.

## ITEM 9B. Other Information

None.

# PART III

## ITEM 10. Directors, Executive Officers and Corporate Governance

Information required to be set forth in Item 10. Directors, Executive Officers and Corporate Governance, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2013 Annual Meeting of Unitholders expected to be filed no later than April 30, 2013.

## ITEM 11. Executive Compensation

Information required to be set forth in Item 11. Executive Compensation, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2013 Annual Meeting of Unitholders expected to be filed no later than April 30, 2013.

## ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

Information required to be set forth in Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2013 Annual Meeting of Unitholders expected to be filed no later than April 30, 2013.

## ITEM 13. Certain Relationships and Related Transactions, and Director Independence

Information required to be set forth in Item 13. Certain Relationships and Related Transactions, and Director Independence, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2013 Annual Meeting of Unitholders expected to be filed no later than April 30, 2013.

## ITEM 14. Principal Accountant Fees and Services

Information required to be set forth in Item 14. Principal Accountant Fees and Services, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2013 Annual Meeting of Unitholders expected to be filed no later than April 30, 2013.

# PART IV

## ITEM 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial Statements

You should read the Index to Consolidated Financial Statements included in Item 8 of this Form 10-K for a list of all financial statements filed as part of this report, which is incorporated herein by reference.

(2) Financial Statement Schedules

All schedules have been omitted because they are not required or because the required information is contained in the financial statements or notes thereto.

(3) Exhibits

| Exhibit Number | Description |
|---|---|
| 2.1 | Agreement and Plan of Redemption and Merger dated September 5, 2007 by and among MarkWest Hydrocarbon, Inc., MarkWest Energy Partners, L.P. and MWEP, L.L.C. (incorporated by reference to the Current Report on Form 8-K filed September 6, 2007). |
| 2.2+ | Agreement and Plan of Merger dated as of May 7, 2012 among Keystone Midstream Services, L.L.C., R.E. Gas Development, L.L.C., Stonehenge Energy Resources, L.P., Summit Discovery Resources II, L.L.C., MarkWest Liberty Midstream & Resources, L.L.C., MarkWest Liberty Bluestone, L.L.C. and KMS Shareholder Representative, L.L.C. (incorporated by reference to Quarterly Report on Form 10-Q filed August 6, 2012). |
| 3.1 | Certificate of Limited Partnership of MarkWest Energy Partners, L.P. (incorporated by reference to the Registration Statement (No. 33-81780) on Form S-1 filed January 31, 2002). |
| 3.2 | Certificate of Formation of MarkWest Energy Operating Company, L.L.C. (incorporated by reference to the Registration Statement (No. 33-81780) on Form S-1 filed January 31, 2002). |
| 3.3 | Amended and Restated Limited Liability Company Agreement of MarkWest Energy Operating Company, L.L.C., dated as of May 24, 2002 (incorporated by reference to the Current Report on Form 8-K filed June 7, 2002). |
| 3.4 | Certificate of Formation of MarkWest Energy GP, L.L.C. (incorporated by reference to the Registration Statement (No. 33-81780) on Form S-1 filed January 31, 2002). |
| 3.5 | Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of May 24, 2002 (incorporated by reference to the Current Report on Form 8-K filed June 7, 2002). |
| 3.6 | Third Amended and Restated Agreement of Limited Partnership of MarkWest Energy Partners, L.P., dated as of February 21, 2008 (incorporated by reference to the Current Report on Form 8-K filed February 21, 2008). |
| 3.7 | Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of December 31, 2004 (incorporated by reference to the Form S-4 Registration Statement filed July 2, 2009). |
| 3.8 | Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of January 19, 2005 (incorporated by reference to the Form S-4 Registration Statement filed July 2, 2009). |
| 3.9 | Amendment No. 3 to Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of February 21, 2008 (incorporated by reference to the Form S-4 Registration Statement filed July 2, 2009). |
| 3.10 | Amendment No. 4 to Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of March 31, 2008 (incorporated by reference to the Form S-4 Registration Statement filed July 2, 2009). |
| 3.11 | Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of MarkWest Energy Partners, L.P., dated December 29, 2011 (incorporated by reference to the Current Report on Form 8-K filed December 30, 2011). |
| 4.1 | Indenture dated as of April 15, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the several guarantors named therein, and Wells Fargo Bank, N.A., as trustee (incorporated by reference to the Current Report on Form 8-K filed April 15, 2008). |

| Exhibit Number | Description |
|---|---|
| 4.2 | Form of 8.75% Series A and Series B Senior Notes due 2018 with attached notation of Guarantees (incorporated by reference to Exhibits A and D of Exhibit 4.1 hereto, which is incorporated by reference to the Current Report on Form 8-K filed April 15, 2008). |
| 4.3 | Registration Rights Agreement dated as of April 15, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, and the several guarantors named therein, and J.P. Morgan Securities Inc., RBC Capital Markets Corporation, Wachovia Capital Markets, LLC, Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Fortis Securities LLC and SunTrust Robinson Humphrey, Inc. (incorporated by reference to the Current Report on Form 8-K filed April 15, 2008). |
| 4.4 | Registration Rights Agreement dated as of May 1, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, and the several guarantors named therein, and J.P. Morgan Securities Inc., RBC Capital Markets Corporation, Wachovia Capital Markets, LLC, Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Fortis Securities LLC and SunTrust Robinson Humphrey, Inc. (incorporated by reference to the Current Report on Form 8-K filed May 1, 2008). |
| 4.5 | First Supplemental Indenture, dated as of April 25, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009). |
| 4.6 | Second Supplemental Indenture, dated as of August 4, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009). |
| 4.7 | Third Supplemental Indenture, dated as of September 15, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009). |
| 4.8 | Indenture Release of Subsidiary Guarantor dated as of May 1, 2009, among MarkWest Energy Partners, L.P., and Wells Fargo Bank, N.A. (incorporated by reference to the Quarterly Report on Form 10-Q filed August 10, 2009). |
| 4.9 | Indenture Release of Subsidiary Guarantor dated as of October 31, 2009, among MarkWest Energy Partners, L.P. and Wells Fargo Bank, N.A. (incorporated by reference to the Registration Statement on Form S-3 filed January 13, 2010). |
| 4.10 | Fourth Supplemental Indenture dated as of March 10, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Quarterly Report on Form 10-Q filed May 9, 2011). |
| 4.11 | Fifth Supplemental Indenture dated as of October 21, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Quarterly Report on Form 10-Q filed November 7, 2011). |

| Exhibit Number | Description |
|---|---|
| 4.12 | Sixth Supplemental Indenture, dated as of November 10, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Current Report on Form 8-K filed November 15, 2011). |
| 4.13 | Indenture, dated as of November 2, 2010, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Current Report on Form 8-K filed November 3, 2010). |
| 4.14 | First Supplemental Indenture, dated as of November 2, 2010, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Current Report on Form 8-K filed November 3, 2010). |
| 4.15 | Form of 6.75% Senior Notes due 2020 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.14 hereto, which is incorporated by reference to the Current Report on Form 8-K filed November 3, 2010). |
| 4.16 | Second Supplemental Indenture, dated as of February 24, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Current Report on Form 8-K filed February 24, 2011). |
| 4.17 | Form of 6.5% Senior Notes due 2021 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.16 hereto, which is incorporated by reference to the Current Report on Form 8-K filed February 24, 2011). |
| 4.18 | Third Supplemental Indenture dated as of March 10, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Quarterly Report on Form 10-Q filed May 9, 2011). |
| 4.19 | Fourth Supplemental Indenture dated as of October 21, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Quarterly Report on Form 10-Q filed November 7, 2011). |
| 4.20 | Fifth Supplemental Indenture, dated as of November 3, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Current Report on Form 8-K filed November 7, 2011). |
| 4.21 | Form of 6.25% Senior Notes due 2022 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.20 hereto, which is incorporated by reference to the Current Report on Form 8-K filed November 7, 2011). |
| 4.22 | Sixth Supplemental Indenture, dated as of December 27, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Annual Report on Form 10-K filed February 28, 2012). |

| Exhibit Number | Description |
|---|---|
| 4.23 | Seventh Supplemental Indenture dated as of January 30, 2012, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Quarterly Report on Form 10-Q filed May 7, 2012). |
| 4.24 | Eighth Supplemental Indenture, dated as of August 10, 2012, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Current Report on Form 8-K filed August 10, 2012). |
| 4.25 | Form of 5.5% Senior Notes due 2023 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.24 hereto, which is incorporated by reference to the Current Report on Form 8-K filed August 10, 2012). |
| 4.26 | Ninth Supplemental Indenture, dated as of December 21, 2012, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Post-Effective Amendment No. 1 to Registration Statement on Form S-3 filed January 7, 2013). |
| 4.27 | Tenth Supplemental Indenture, dated as of January 10, 2013, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to the Current Report on Form 8-K filed January 10, 2013). |
| 4.28 | Form of 4.5% Senior Notes due 2023 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.27 hereto, which is incorporated by reference to the Current Report on Form 8-K filed January 10, 2013). |
| 4.29 | Registration Rights Agreement dated December 29, 2011 between MarkWest Energy Partners, L.P. and M&R MWE Liberty, LLC (incorporated by reference to the Annual Report on Form 10-K filed February 28, 2012). |
| 10.1 | Amended and Restated Revolving Credit Agreement dated as of July 1, 2010 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as successor Administrative Agent, Issuing Bank and Swingline Linder, Royal Bank of Canada, as prior administrative agent, RBC Capital Markets, as Syndication Agent, BNP Paribas, Morgan Stanley Bank and U.S. Bank National Association, as Documentation Agents, and the lenders party thereto (incorporated by reference to the Current Report on Form 8-K filed July 7, 2010). |
| 10.2 | Joinder Agreement dated as of July 29, 2010 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, individually and as Administrative Agent, Issuing Bank and Swingline Lender and Goldman Sachs Bank USA (incorporated by reference to the Current Report on Form 8-K filed August 4, 2010). |
| 10.3 | Joinder Agreement dated as of June 15, 2011 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, individually and as Administrative Agent, Issuing Bank and Swingline Lender and Citibank, N.A. (incorporated by reference to the Current Report on Form 8-K filed June 17, 2011). |

| Exhibit Number | Description |
|---|---|
| 10.4 | First Amendment to Amended and Restated Credit Agreement dated as of September 7, 2011 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, and the other agents and lenders party thereto (incorporated by reference to the Current Report on Form 8-K filed September 13, 2011). |
| 10.5 | Second Amendment to Amended and Restated Credit Agreement dated as of December 29, 2011, among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, and the other agents and lenders party thereto (incorporated by reference to the Current Report on Form 8-K filed December 30, 2011). |
| 10.6 | Third Amendment to Amended and Restated Credit Agreement dated as of June 29, 2012, among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, and the other agents and lenders party thereto (incorporated by reference to the Current Report on Form 8-K filed June 29, 2012). |
| 10.7 | Fourth Amendment to Amended and Restated Credit Agreement dated as of December 20, 2012, among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, and the other agents and lenders party thereto (incorporated by reference to the Current Report on Form 8-K filed December 26, 2012). |
| 10.8 | Equity Distribution Agreement dated as of November 7, 2012, among MarkWest Energy Partners, L.P., MarkWest Energy Operating Company, L.L.C. and Citigroup Global Markets Inc. (incorporated by reference to the Current Report on Form 8-K filed November 7, 2012). |
| 10.9 | Services Agreement dated January 1, 2004 between MarkWest Energy GP, L.L.C. and MarkWest Hydrocarbon, Inc. (incorporated by reference to the Annual Report on Form 10-K filed March 15, 2004). |
| 10.10+ | Natural Gas Liquids Purchase Agreement dated August 25, 2006 between ONEOK Hydrocarbon, L.P. and MarkWest Western Oklahoma Gas Company, L.L.C., now known as MarkWest Oklahoma Gas Company, L.L.C. (incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009). |
| 10.11+ | Amendment to the Natural Gas Liquids Purchase Agreement effective as of November 1, 2008 by and between MarkWest Oklahoma Gas Company, L.L.C. and ONEOK Hydrocarbon, L.P. (incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009). |
| 10.12+ | Raw Product Purchase Agreement dated February 11, 2005 between MarkWest Energy East Texas Gas Company, L.P., now known as MarkWest Energy East Texas Gas Company, L.L.C., and Dynegy Liquids Marketing and Trade, now known as Targa Liquids Marketing and Trade (incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009). |
| 10.13+ | Amendment to the Raw Product Purchase Agreement effective as of December 1, 2009 by and between Targa Liquids Marketing and Trade and MarkWest Energy East Texas Gas Company, L.L.C. (incorporated by reference to the Annual Report on Form 10-K filed March 1, 2010). |
| 10.14 | Exchange Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P., MarkWest Hydrocarbon, Inc., and MarkWest Energy, GP L.L.C. (incorporated by reference to the Current Report on Form 8-K filed September 6, 2007). |

| Exhibit Number | Description |
|---|---|
| 10.15 | Form of Second Amended and Restated Indemnification Agreement dated April 24, 2008 by and among MarkWest Energy Partners, L.P., MarkWest Energy GP, L.L.C., and each director and officer of MarkWest Energy GP, L.L.C., including the following named executive officers: Frank Semple, President and Chief Executive Officer; Nancy Buese, Senior Vice President and Chief Financial Officer; Randy Nickerson, Senior Vice President and Chief Commercial Officer; John Mollenkopf, Senior Vice President and Chief Operations Officer; and C. Corwin Bromley, Senior Vice President, General Counsel and Secretary (incorporated by reference to the Quarterly Report on Form 10-Q filed August 11, 2008). |
| 10.16 | MarkWest Energy Partners, L.P. Long-Term Incentive Plan (incorporated by reference to the Current Report on Form 8-K filed June 7, 2002). |
| 10.17 | First Amendment to MarkWest Energy Partners, L.P. Long-Term Incentive Plan (incorporated by reference to the Current Report on Form 8-K filed June 7, 2002). |
| 10.18 | MarkWest Energy Partners, L.P. 2008 Long-Term Incentive Plan (incorporated by reference to the Form S-4/A Registration Statement filed December 21, 2007). |
| 10.19 | Amendment No. 1 to MarkWest Energy Partners, L.P. 2008 Long-Term Incentive Plan (incorporated by reference to Appendix B to the Proxy Statement on Schedule 14A filed April 20, 2012). |
| 10.20Δ | Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Frank Semple (incorporated by reference to the Current Report on Form 8-K filed September 11, 2007). |
| 10.21Δ | Form of Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Nancy K. Buese, C. Corwin Bromley, John C. Mollenkopf and Randy S. Nickerson (incorporated by reference to the Current Report on Form 8-K filed September 11, 2007). |
| 10.22+ | Purchase and Sale Agreement dated as of January 3, 2011 by and between EQT Gathering, LLC and MarkWest Energy Appalachia, L.L.C. (incorporated by reference to the Quarterly Report on Form 10-Q filed May 9, 2011). |
| 10.23+ | Letter Agreement dated February 1, 2011 between EQT Gathering, LLC and MarkWest Energy Appalachia, L.L.C. (incorporated by reference to the Quarterly Report on Form 10-Q filed May 9, 2011). |
| 10.24+ | Contribution Agreement dated December 29, 2011 among M&R MWE Liberty, LLC, MarkWest Energy Partners, L.P. and MarkWest Liberty Gas Gathering L.L.C. (incorporated by reference to the Annual Report on Form 10-K filed February 28, 2012). |
| 10.25+ | Limited Liability Company Agreement of MarkWest Utica EMG, L.L.C., dated December 29, 2011 and effective January 1, 2012, between MarkWest Utica Operating Company, L.L.C. and EMG Utica, LLC (incorporated by reference to the Annual Report on Form 10-K filed February 28, 2012). |
| 12.1* | Computation of Ratio of Earnings to Fixed Charges |
| 14.1 | MarkWest Energy Partners, L.P. Code of Conduct and Ethics (incorporated by reference to the Current Report on Form 8-K filed October 31, 2012). |
| 21.1* | List of subsidiaries |
| 23.1* | Consent of Deloitte & Touche LLP |

| Exhibit Number | Description |
|---|---|
| 31.1* | Chief Executive Officer Certification Pursuant to Section 13a-14 of the Securities Exchange Act |
| 31.2* | Chief Financial Officer Certification Pursuant to Section 13a-14 of the Securities Exchange Act |
| 32.1* | Certification of Chief Executive Officer of the General Partner pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2* | Certification of Chief Financial Officer of the General Partner pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 101* | The following financial information from the annual report on Form 10-K of MarkWest Energy Partners, L.P. for the year ended December 31, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Changes in Equity and Comprehensive Income, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements, tagged as blocks of text. |

+ Application has been made to the Securities and Exchange Commission for confidential treatment of certain provisions of these exhibits. Omitted material for which confidential treatment has been requested and has been filed separately with the Securities and Exchange Commission.

* Filed herewith.

Δ Identifies each management contract or compensatory plan or arrangement.

(b) The following exhibits are filed as part of this report: See Item 15(a)(2) above.

(c) The following financial statement schedules are filed as part of this report: None required.

## SIGNATURES

Pursuant to the requirements of section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

MarkWest Energy Partners, L.P.
(Registrant)

By: MarkWest Energy GP, L.L.C.,
Its General Partner

Date: February 27, 2013

By: /s/ FRANK M. SEMPLE
Frank M. Semple
*Chairman, President and Chief Executive Officer*
*(Principal 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 with MarkWest Energy GP, L.L.C., the General Partner of MarkWest Energy Partners, L.P., the Registrant, and on the dates indicated.

Date: February 27, 2013

By: /s/ FRANK M. SEMPLE
Frank M. Semple
*Chairman, President and Chief Executive Officer*
*(Principal Executive Officer)*

Date: February 27, 2013

By: /s/ NANCY K. BUESE
Nancy K. Buese
*Senior Vice President and Chief Financial Officer*
*(Principal Financial Officer)*

Date: February 27, 2013

By: /s/ PAULA L. ROSSON
Paula L. Rosson
*Vice President and Chief Accounting Officer*
*(Principal Accounting Officer)*

Date: February 27, 2013

By: /s/ DONALD D. WOLF
Donald D. Wolf
*Lead Director*

Date: February 27, 2013

By: /s/ KEITH E. BAILEY
Keith E. Bailey
*Director*

| | |
|---|---|
| Date: February 27, 2013 | By: /s/ MICHAEL L. BEATTY<br>Michael L. Beatty<br>*Director* |
| Date: February 27, 2013 | By: /s/ CHARLES K. DEMPSTER<br>Charles K. Dempster<br>*Director* |
| Date: February 27, 2013 | By: /s/ ANNE E. FOX MOUNSEY<br>Anne E. Fox Mounsey<br>*Director* |
| Date: February 27, 2013 | By: /s/ DONALD C. HEPPERMANN<br>Donald C. Heppermann<br>*Director* |
| Date: February 27, 2013 | By: /s/ WILLIAM P. NICOLETTI<br>William P. Nicoletti<br>*Director* |
| Date: February 27, 2013 | By: /s/ RANDALL J. LARSON<br>Randall J. Larson<br>*Director* |

(This page has been left blank intentionally.)

(This page has been left blank intentionally.)

# CORPORATE INFORMATION



EXECUTIVE OFFICERS OF MARKWEST ENERGY GP, LLC

**Frank M. Semple**
Chairman of the Board, President and Chief Executive Officer

**C. Corwin Bromley**
Senior Vice President,
General Counsel and Secretary

**Nancy K. Buese**
Senior Vice President and Chief Financial Officer

**John C. Mollenkopf**
Senior Vice President and Chief Operating Officer

**Randy S. Nickerson**
Senior Vice President and Chief Commercial Officer

**CONTACT INFORMATION**

MarkWest Energy Partners, LP
1515 Arapahoe Street
Tower 1, Suite 1600
Denver, Colorado 80202-2137
Tel: 800.730.8388
Fax: 303.290.8769
Website: www.markwest.com

*Investor Relations*
Tel: 866.858.0482
Email:
investorrelations@markwest.com

**TRANSFER AGENT AND REGISTRAR**

Wells Fargo Shareowner Services
Tel: 800.468.9716
Website: www.shareowneronline.com

*Send unitholder inquiries to:*
Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, Minnesota 55075

**COMMON UNIT LISTING**

New York Stock Exchange
Ticker Symbol: MWE

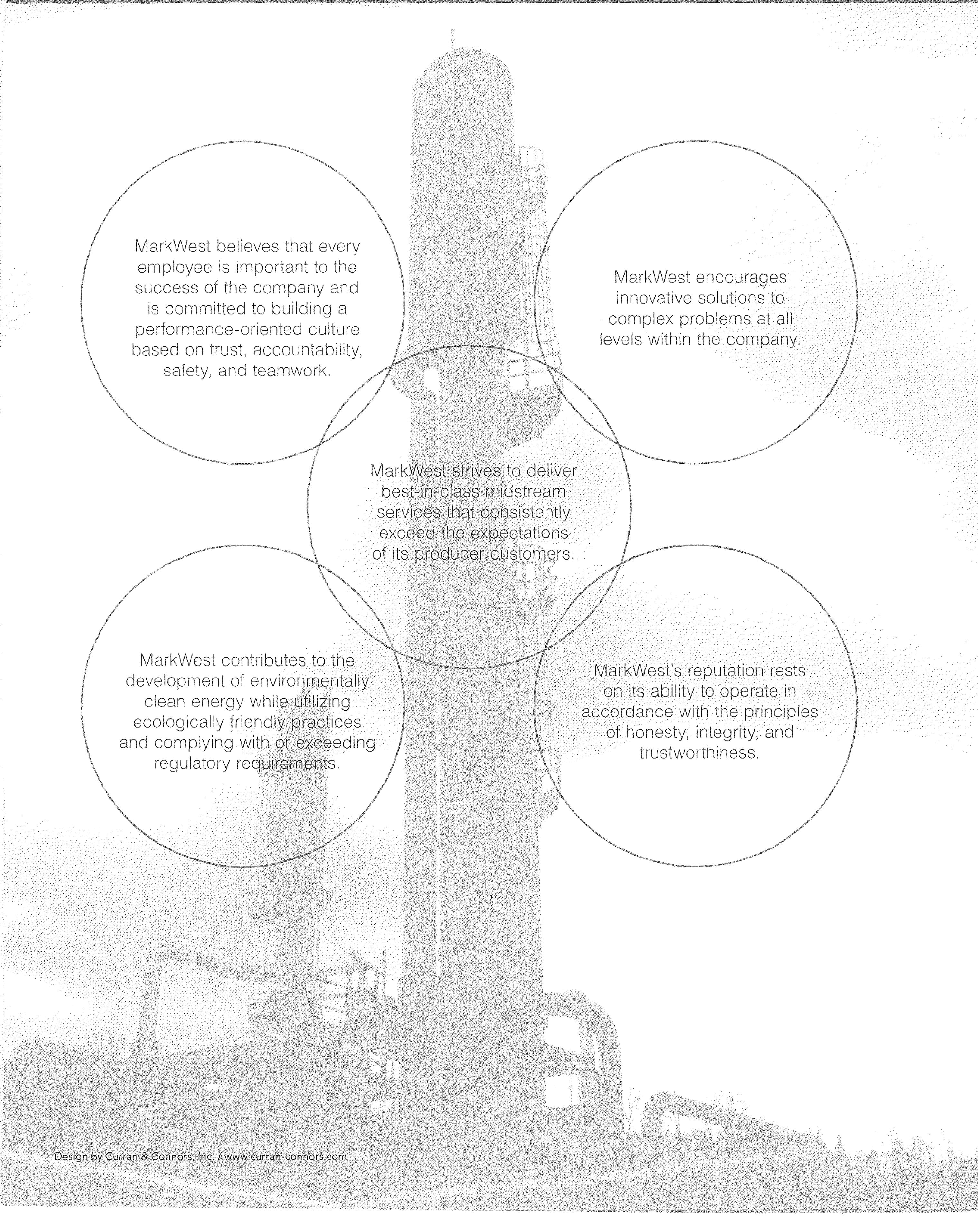
**NYSE AND SEC CERTIFICATIONS**

The annual CEO certification required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual was submitted without qualification by Frank M. Semple on June 28, 2012.

MarkWest's Chief Executive Officer and Chief Financial Officer have provided certifications to the U.S. Securities and Exchange Commission as required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002. These certifications are included as Exhibits 31.1, 31.2, 32.1 and 32.2 to the Partnership's Form 10-K for the year ended December 31, 2012.

MARKWEST
Energy Partners, L.P.

# OUR CORE PRINCIPLES



MarkWest believes that every employee is important to the success of the company and is committed to building a performance-oriented culture based on trust, accountability, safety, and teamwork.

MarkWest encourages innovative solutions to complex problems at all levels within the company.

MarkWest strives to deliver best-in-class midstream services that consistently exceed the expectations of its producer customers.

MarkWest contributes to the development of environmentally clean energy while utilizing ecologically friendly practices and complying with or exceeding regulatory requirements.

MarkWest's reputation rests on its ability to operate in accordance with the principles of honesty, integrity, and trustworthiness.

Design by Curran & Connors, Inc. / www.curran-connors.com

# AREAS OF OPERATION



MARKWEST
Energy Partners, L.P.

1515 Arapahoe Street, Tower 1, Suite 1600
Denver, Colorado 80202-2137
www.markwest.com