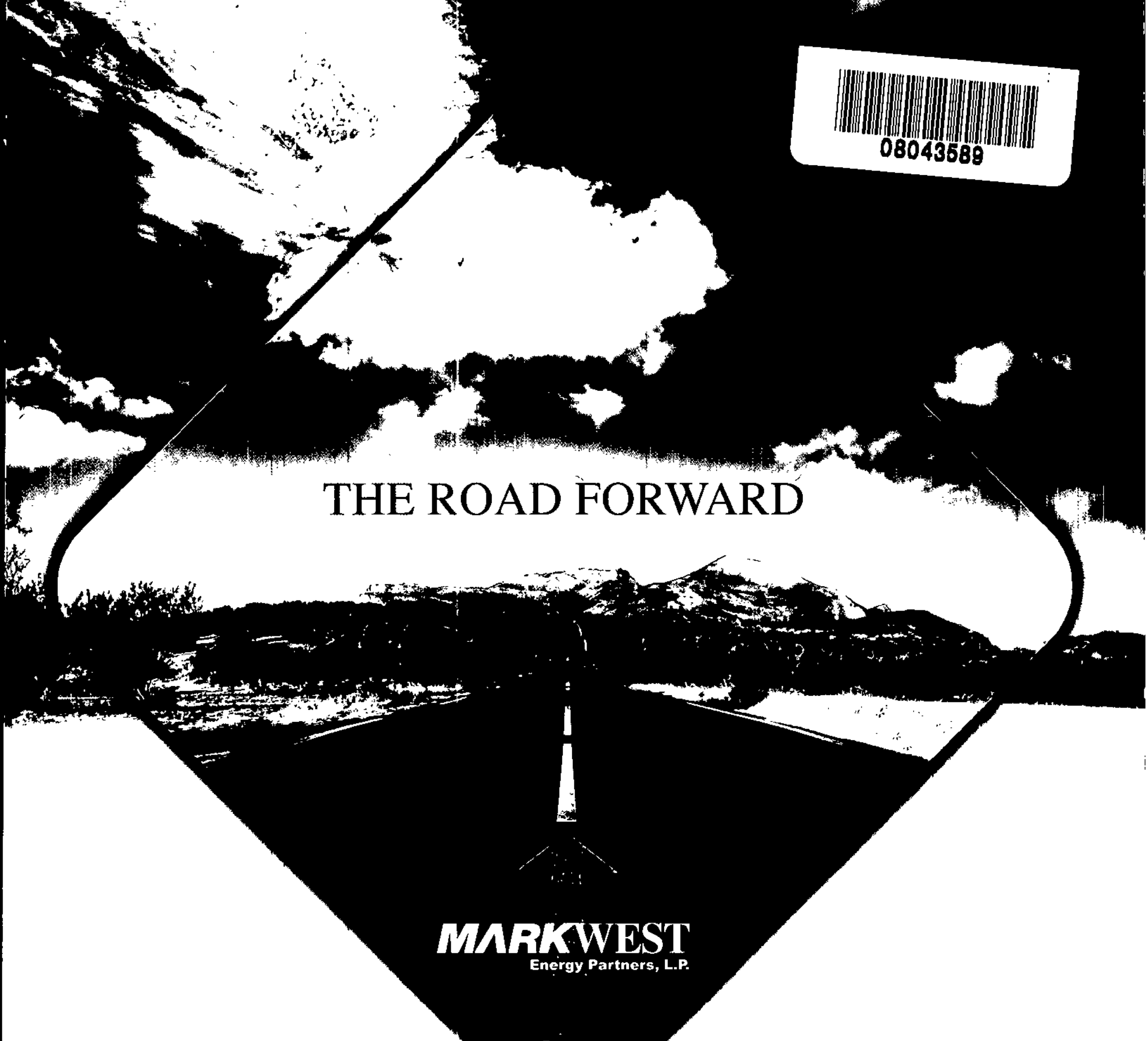


THE ROAD FORWARD

MARKWEST ENERGY PARTNERS

2007 ANNUAL REPORT

Financial and Operating Summary

SELECTED FINANCIAL DATA

($000, except per unit data)	Year ended December 31, 2005	2006	2007
Revenue	$ 541,090	$ 629,911	$ 602,879
Net income	$ 2,355	$ 70,084	$ 17,199
Interest in net income			
General partner	$ 2,113	$ (843)	$ 12,821
Limited partners	$ 242	$ 70,927	$ 4,378
Net income per limited partner unit			
Basic	$ 0.01	$ 2.45	$ 0.12
Diluted	$ 0.01	$ 2.44	$ 0.12
Weighted average units outstanding			
Basic	21,790	28,966	35,496
Diluted	21,858	29,098	35,657
Declared distributions per limited partner unit	$ 1.60	$ 1.79	$ 2.09
Cash Flow Data			
Net cash flow provided by (used in):			
Operating activities	$ 42,090	$ 150,977	$ 149,399
Investing activities	$ (469,308)	$ (119,338)	$ (312,085)
Financing activities	$ 423,060	$ (17,342)	$ 154,789
Other Financial Data			
Distributable cash flow*	$ 44,041	$ 117,911	$ 162,611
Balance Sheet Data			
Working capital	$ 11,944	$ 4,258	$ (19,734)
Total assets	$ 1,046,093	$ 1,114,780	$ 1,392,834
Total debt	$ 601,262	$ 526,865	$ 552,695
Partners' capital	$ 307,175	$ 452,649	$ 611,323
Total debt-to-book capitalization	66%	54%	47%

OPERATING DATA

	2005	2006	2007
Southwest			
East Texas			
Gathering systems throughput (Mcf/d)	321,000	378,100	413,700
NGL product sales (gallons)	126,476,000	161,437,000	179,601,000
Oklahoma			
Foss Lake gathering system throughput (Mcf/d)	75,800	87,500	104,000
Woodford gathering system throughput (Mcf/d)	N/A	34,000	114,000
Grimes gathering system throughput (Mcf/d)	N/A	N/A	12,500
Arapaho NGL product sales (gallons)	60,903,000	79,093,000	87,522,000
Other Southwest			
Appleby gathering system throughput (Mcf/d)	33,400	34,200	58,700
Other gathering systems throughput (Mcf/d)	16,500	18,300	8,700
Northeast			
Appalachia			
Natural gas processed for a fee (Mcf/d)	197,000	203,000	200,200
NGLs fractionated for a fee (Gal/d)	430,000	454,800	452,200
NGL product sales (gallons)	41,700,000	43,271,000	43,815,100
Michigan			
Natural gas processed for a fee (Mcf/d)	6,600	6,500	5,200
NGL product sales (gallons)	5,697,000	5,643,000	3,898,600
Crude oil transported for a fee (Bbl/d)	14,200	14,500	14,000
Gulf Coast			
Javelina			
Natural gas processed for a fee (Mcf/d)	115,000	124,300	114,500
Liquids fractionated for a fee (Bbl/d)	19,400	26,200	25,000

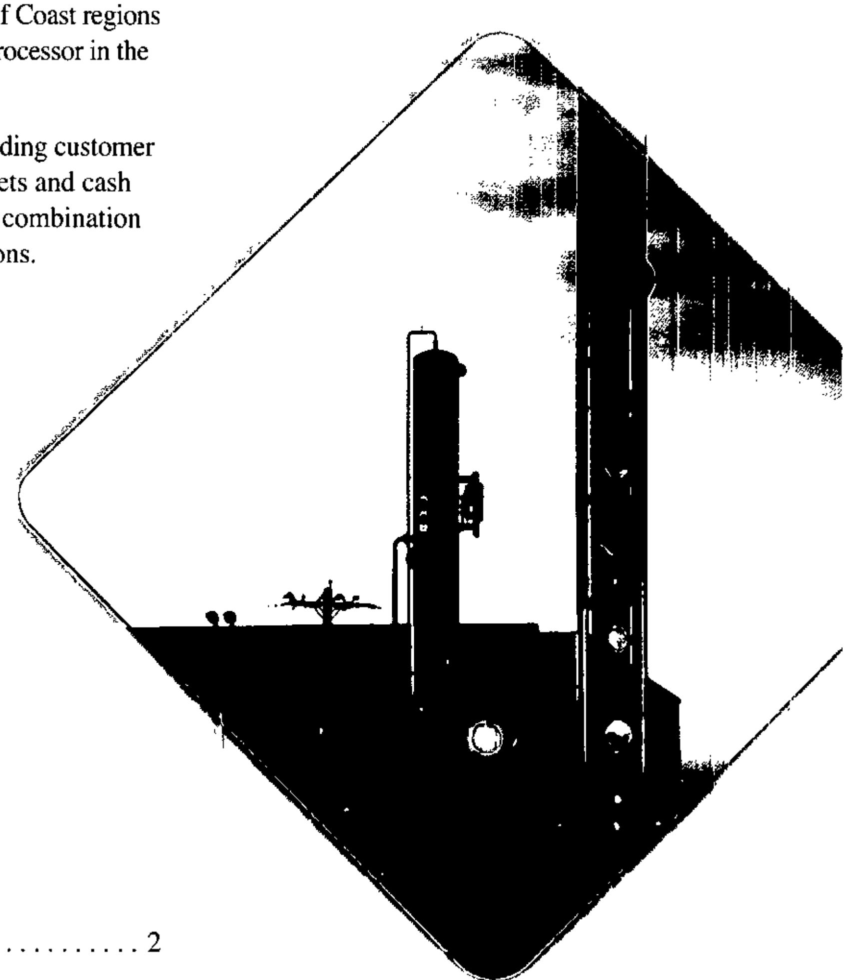
*See table below for reconciliation of distributable cash flow, a non-GAAP measure, to net income.

	2005	2006	2007
Net income	$ 2,355	$ 70,084	$ 17,199
Adjustments to reconcile net income to distributable cash flow			
Depreciation, amortization, accretion, and impairments	29,349	46,142	57,313
Amortization of deferred financing costs	6,780	9,094	2,717
Non-cash earnings from unconsolidated affiliates	2,153	(5,316)	(5,309)
Distributions from (contributions to) unconsolidated affiliates net of expansion capital expenditures	1,849	(9,424)	10,840
Non-cash compensation expense	3,131	15,171	12,960
Non-cash derivative activity	657	(6,245)	62,376
Other	(28)	888	553
Loss (gain) on disposal of property, plant, and equipment	(24)	(192)	7,564
Maintenance capital expenditures	(2,181)	(2,291)	(3,602)
Distributable cash flow	$ 44,041	$ 117,911	$ 162,611

Company Profile

We are a growth-oriented master limited partnership engaged in the gathering, transportation, and processing of natural gas; the transportation, fractionation, marketing, and storage of natural gas liquids, or NGLs; and the gathering and transportation of crude oil. We have extensive natural gas gathering, processing, and transmission operations in the southwestern and Gulf Coast regions of the United States and are the largest natural gas processor in the Appalachian region.

Our primary business strategy is to provide outstanding customer service at competitive rates and to expand our assets and cash flow available for distribution through a balanced combination of organic growth projects and selective acquisitions.



Contents

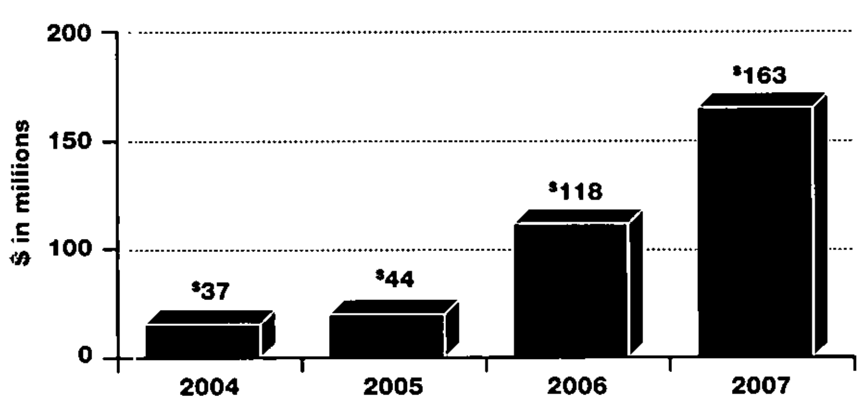
Disclaimer

The statements contained in this Annual Report contain "forward-looking statements." 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 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 2007, 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.

Letter to Unitholders

MarkWest Energy Partners completed an exceptional year in 2007. We delivered strong financial performance, returned record distributions to our unitholders, and further strengthened our balance sheet. Operationally, we successfully executed a very aggressive capital expenditure program while continuing our reputation for delivering exceptional customer service. We expanded existing facilities and identified significant growth opportunities in our key operating areas. Our success in 2007 – coupled with the merger with MarkWest Hydrocarbon, Inc., in early 2008 – positions us to deliver long-term value in this very dynamic and unique market. Highlights of our 2007 financial performance include record Distributable Cash Flow (DCF) of approximately $163 million, an increase of nearly 40 percent compared to 2006. While a portion of these increases are attributable to higher prices in 2007, more than 60 percent of the increase is due to higher volumes resulting from significant organic growth.

Distributable Cash Flow

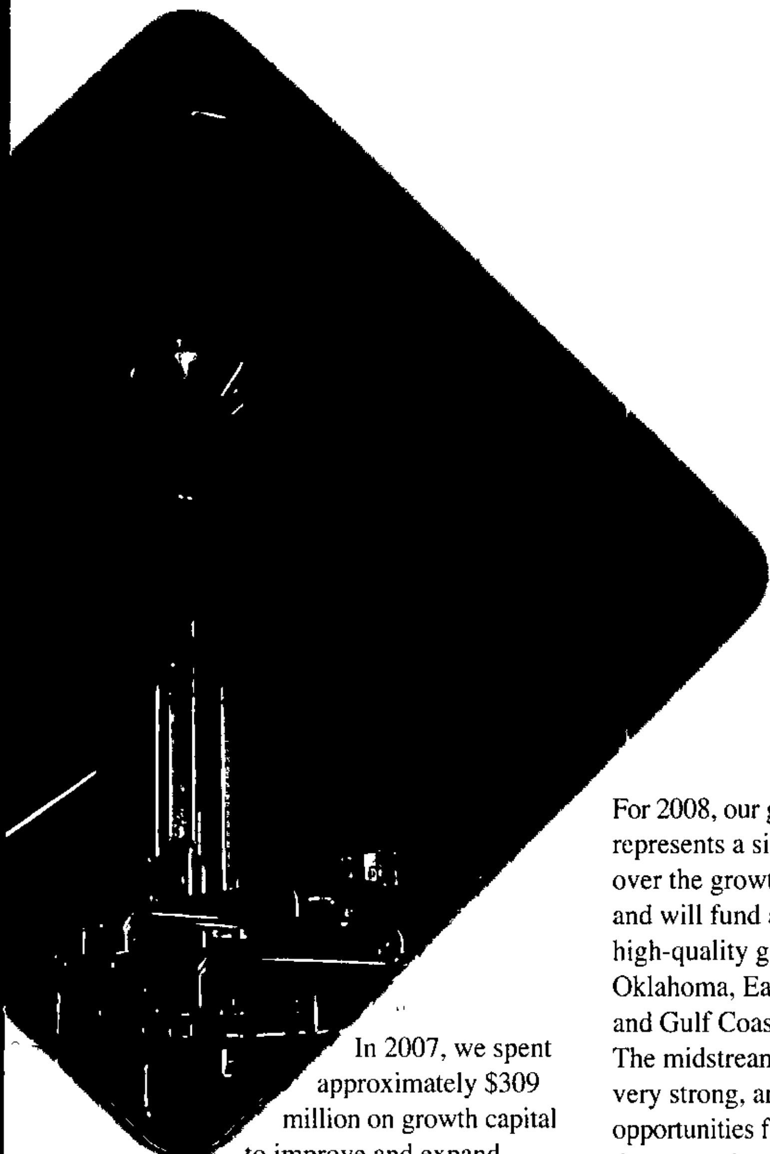


Excluding non-cash costs associated with the mark-to-market of derivative instruments, non-cash compensation expense, and the loss (gain) on disposal of property, plant, and equipment, net income for 2007 was $100 million, an increase of 27 percent compared to $79 million in 2006. Our balance sheet remains very strong, with $1.4 billion in assets at year-end, total debt of $553 million, and a debt-to-capitalization ratio of 47 percent.

These strong financial results allowed us to increase annual distributions to our unitholders for the fifth consecutive year in 2007. Cash distributions for 2007 were $2.16 per unit, a 15 percent increase from 2006. Since going public in May 2002, MarkWest Energy Partners has delivered compound annual growth of distributions per unit of 16 percent.

We continue our proactive strategy to maintain and enhance future cash flows and distributions by hedging the commodity components of our business. Virtually all of our hedge transactions are with our bank group, which enhances our financial flexibility and liquidity. The comprehensive hedge program extends through the end of 2011, with approximately 75 percent of our 2008 commodity exposure hedged through a combination of fixed-price swaps, costless collars, and puts.

In early 2007, we completed a two-for-one stock split and subsequently listed MarkWest Energy Partners on the New York Stock Exchange. We believe these actions will further increase liquidity and improve our position in the financial markets. Additionally, we completed two private-equity transactions in 2007 for a total of $225 million, not including the general-partner contribution. These placements funded a significant portion of our 2007 capital program and will also be used to fund our 2008 capital budget.



In 2007, we spent approximately $309 million on growth capital to improve and expand existing facilities to accommodate the continued growth of our producer customers. Our recent focus on utilizing capital primarily to fund organic growth projects is strategic by design, and demonstrates the quality of our assets and operational performance. Key projects in 2007 include the continued build-out of the Woodford gathering system in southeast Oklahoma, where volumes grew by over 425 percent in 2007; a 20 percent expansion of our gathering system and an 11 percent expansion of our processing plant in western Oklahoma; and the commencement of a $100 million expansion of our Javelina facility in Corpus Christi, Texas.

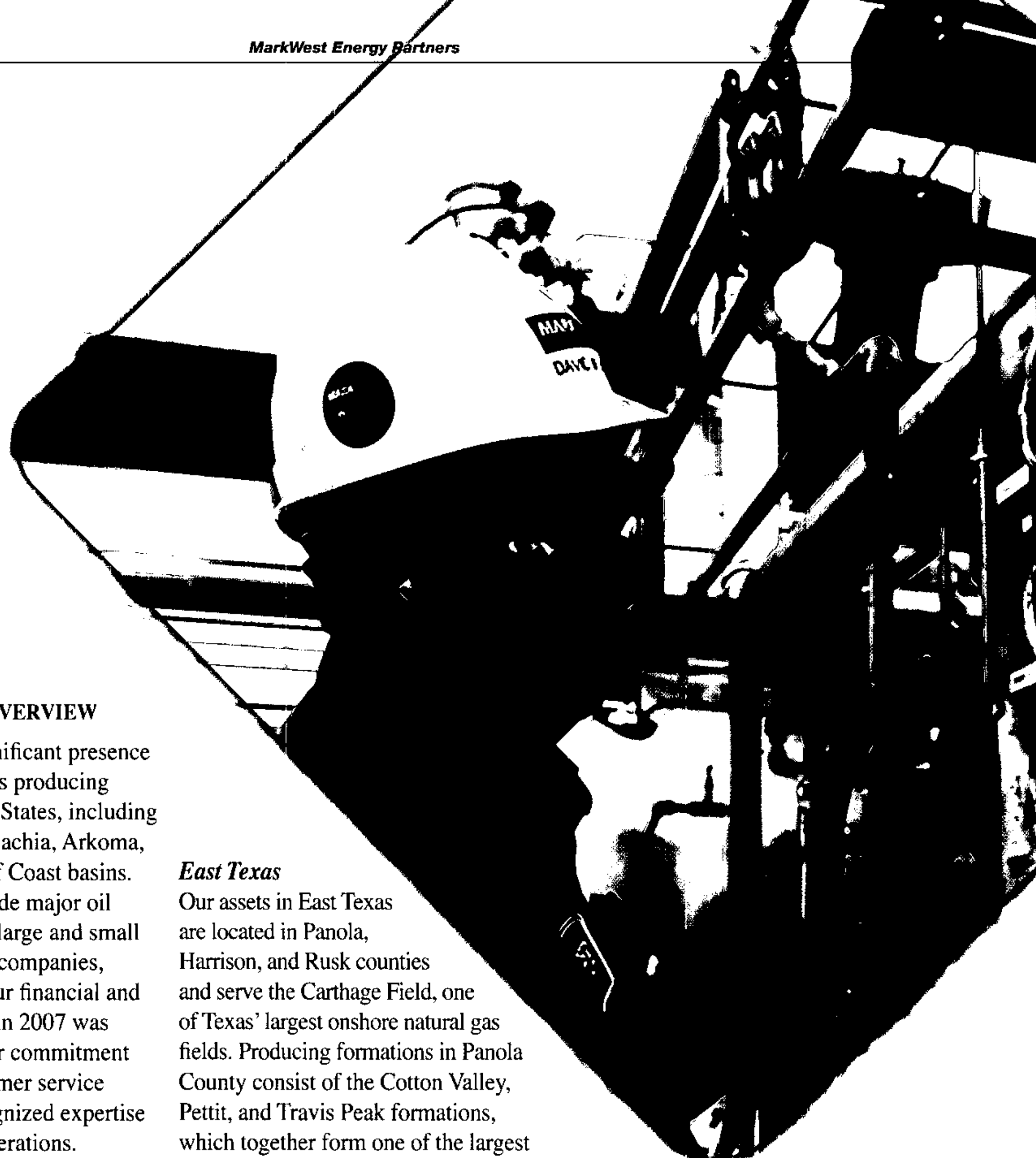
For 2008, our growth capital forecast represents a significant increase over the growth capital in 2007 and will fund a broad range of high-quality growth projects in our Oklahoma, East Texas, Appalachia, and Gulf Coast operating segments. The midstream business remains very strong, and we see excellent opportunities for future expansion in the years ahead.

From a strategic perspective, in early 2008 we completed the merger between MarkWest Hydrocarbon and MarkWest Energy Partners. The merger eliminated the burden of paying a higher percentage of incremental distributions to the general partner; lowered our equity cost of capital by over 2.5 percent as a direct result of the elimination of the incentive distribution rights associated with the master limited partnership structure; created a more focused company whose interests are aligned with one set of equity holders; and improved our efficiency by reducing the costs and distractions of running two public companies. Our people, assets, and focus on customer service have been the key to our success, and the positive attributes of the merger will further enhance the long-term value for our unitholders.

As we look ahead, we will continue to reinforce the qualities that have led to our success: great people, strong operations, a healthy balance sheet, and a continued emphasis on providing best-of-class service for our customers. The demand in the United States for clean-burning natural gas remains very strong, and we intend to be a significant long-term participant in providing gas to the marketplace. I want to thank our employees for their unwavering dedication and hard work as we continue to deliver timely and quality midstream services to our customers that we believe will continue to result in superior and sustainable distribution growth for our unitholders.

Thank you for your continued support.

Frank M. Semple
President and Chief Executive Officer
May 1, 2008



Operations

Business Unit Overview

MarkWest has a significant presence in prolific natural gas producing basins in the United States, including the Anadarko, Appalachia, Arkoma, East Texas, and Gulf Coast basins. Our customers include major oil and gas companies, large and small independent energy companies, and oil refineries. Our financial and operational success in 2007 was largely driven by our commitment to exceptional customer service coupled with a recognized expertise in midstream gas operations.

The following is a summary of our operations, which are organized within three primary business units.

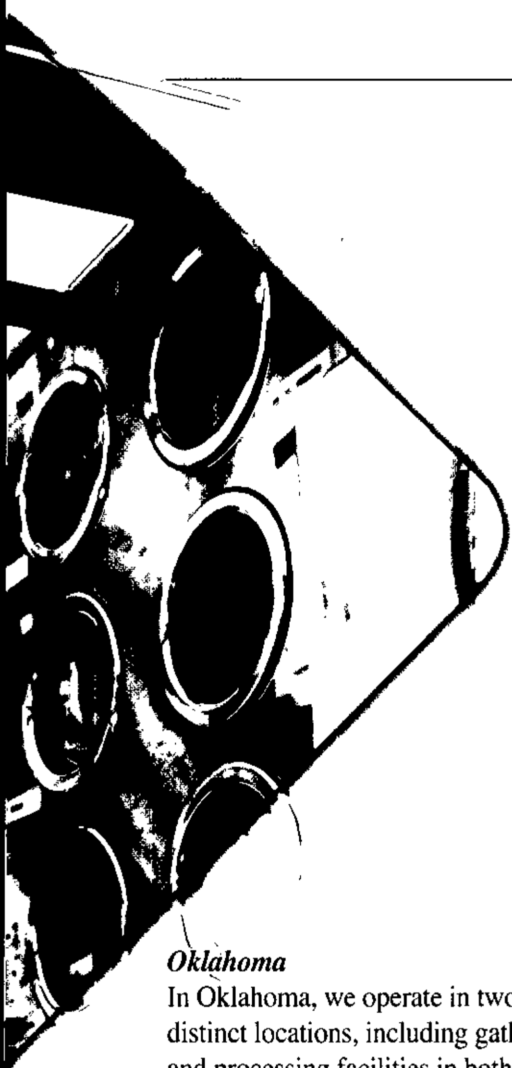
Southwest Business Unit

The Southwest Business Unit consists of the East Texas, Oklahoma, and Other Southwest operating segments. Our assets include 15 natural gas gathering systems with over 1.0 billion cubic feet per day of capacity, two natural gas processing plants, and four intrastate gas pipelines. During 2007 the Southwest Business Unit contributed 75 percent of our revenues and 62 percent of our net operating margin.

East Texas

Our assets in East Texas are located in Panola, Harrison, and Rusk counties and serve the Carthage Field, one of Texas' largest onshore natural gas fields. Producing formations in Panola County consist of the Cotton Valley, Pettit, and Travis Peak formations, which together form one of the largest natural gas producing regions in the United States. Currently, MarkWest gathers approximately 430 million cubic feet per day ("MMcf/d") of natural gas in East Texas, an increase of over 75 percent since we acquired the gathering assets in 2004. The Carthage plant currently processes approximately 180 MMcf/d.

In 2007, we expanded the East Texas gathering system capacity to 440 MMcf/d and added a second residue connection at our Carthage gas plant to a new interstate pipeline, which allows our customers access to the Perryville hub. We also executed new long-term agreements that will add significant gas volumes to our East Texas gathering system and the Carthage gas processing plant. To accommodate the growth, MarkWest will further expand the gathering system capacity from 440 MMcf/d to 530 MMcf/d and increase the processing capacity at the Carthage facility from 200 MMcf/d to 280 MMcf/d. We expect the gathering expansions will be completed throughout 2008, with the processing expansion coming on line in the first quarter of 2009. Future expansions are anticipated to accommodate our new and existing customers' planned horizontal drilling programs.



Oklahoma

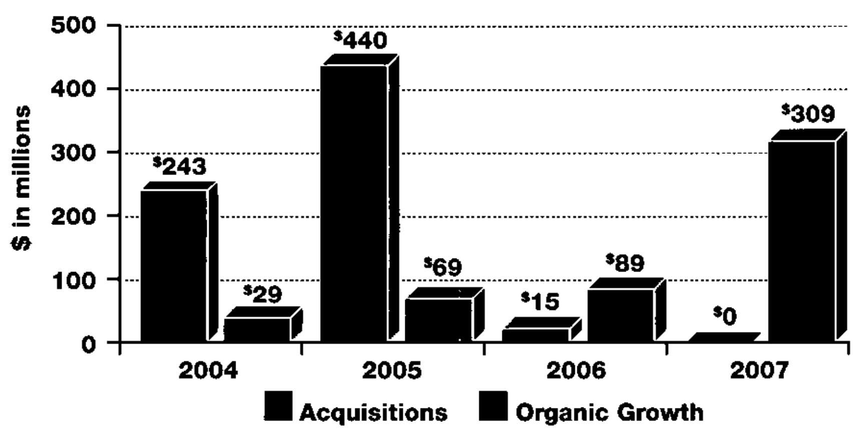
In Oklahoma, we operate in two distinct locations, including gathering and processing facilities in both western and southeast Oklahoma.

In western Oklahoma, our assets include the Foss Lake gathering system and the Arapaho processing plant, which serve producers in the Anadarko basin in Roger Mills, Custer, and Ellis counties. In 2007, we expanded the capacity of the Foss Lake gathering system from 100 MMcf/d to 120 MMcf/d and the Arapaho gas plant from 90 MMcf/d to 100 MMcf/d; we also added a new residue gas connection providing our customers with a second interstate pipeline delivery option. Since our 2003 acquisition of the Foss Lake gathering system, throughput volumes have increased by more than 100 percent, surpassing our existing processing facility capacity. As a result, we are constructing a new processing plant adjacent to our existing Arapaho gas processing facility, which will be operational by mid-2008. This expansion will increase system processing capacity from 100 MMcf/d to 160 MMcf/d.

In southeast Oklahoma, we recently constructed a 300 MMcf/d gathering system to serve producer customers in the emerging Woodford Shale play in the Arkoma Basin, where our throughput volumes increased from 34 MMcf/d to 180 MMcf/d in 2007. We expect to further expand our gathering assets in Woodford Shale over the next several years to accommodate anticipated growth. In addition, we recently began construction of a gathering system in Pittsburg County, Oklahoma – which is located adjacent to, and will be fully integrated with, our existing Woodford Shale gathering system – to support a producer customer's Hartshorne coal bed methane initiatives. Finally, in early 2008, we acquired an interest in Centrahoma Processing LLC, which owns two gas plants having a total capacity of 100 MMcf/d, to support customers' processing needs.

To accommodate the rapidly expanding Woodford Shale gas volumes, we announced in early 2008 the construction of the Arkoma Connector Pipeline. The roughly 600 MMcf/d interstate pipeline is expected to be completed in the first half of 2009 and will connect our Woodford Shale gathering system to the Midcontinent Express Pipeline at Bennington, Oklahoma. We also entered into an option agreement with Midcontinent Express Pipeline LLC ("MEP"), a 50/50 joint venture between Kinder Morgan Partners LP and Energy Transfer Partners LP, which provides us the right to acquire 10 percent of the equity of MEP after construction is completed and the pipeline is placed into service. The Midcontinent Express Pipeline is a 500-mile, 1.5 billion cubic feet per day interstate natural gas pipeline system that extends from southeast Oklahoma across northeast Texas, northern Louisiana, and central Mississippi to an interconnect with Transco Pipeline in Butler, Alabama.

Capital Investment



Operations

Other Southwest
We own a number of natural gas gathering systems located in Texas, Louisiana, Mississippi, and New Mexico, including the Appleby gathering system that gathers Travis Peak production in Nacogdoches County, Texas. Since our acquisition of the Appleby system in March 2003, its capacity has expanded from 20 MMcf/d to 85 MMcf/d. In addition, we own four intrastate gas pipelines in Texas and New Mexico, which serve utility and industrial customers.

Gulf Coast Business Unit

The Gulf Coast Business Unit is comprised of the Javelina gas processing and fractionation facility in Corpus Christi, Texas, and a 50 percent ownership in the Starfish Pipeline Company ("Starfish"). Starfish is accounted for using the equity method of accounting, and therefore the reported segment income for the Gulf Coast Business Unit is derived entirely from our Javelina operations. In 2007, the Gulf Coast Business Unit contributed 12 percent of revenues and 25 percent of net operating margin.

Acquired in November 2005, Javelina treats, processes, and fractionates off-gas from six local refineries. In October 2007, we announced plans to expand Javelina by constructing a steam methane reformer ("SMR") facility to deliver high-purity hydrogen to our refinery customers beginning in early 2010. Once operational, the SMR facility, combined with the existing facilities at the Javelina plant, will produce in excess of 50 MMcf/d of high-purity hydrogen. The SMR facility is anchored by a long-term fee-based supply agreement.

Acquired in early 2005, Starfish provides gas gathering and transportation services in the Gulf of Mexico and southwestern Louisiana. In 2007, Starfish returned to full operation following the completion of repairs related to Hurricane Rita.

Northeast Business Unit

The Northeast Business Unit includes gathering, processing, and fractionation assets in the Appalachian Basin, as well as a crude oil pipeline and natural gas gathering system and processing plant in Michigan. The Northeast Business Unit generated 13 percent of revenues and 13 percent of net operating margin in 2007.

Appalachia

The Appalachian Basin is a large natural gas producing region characterized by long-lived reserves and modest decline rates. We have operated in the region since 1988 and continue to be the region's largest gas processor. Our operations include gas processing and fractionation, natural gas liquid ("NGL") transportation, propane storage, and marketing. Our Appalachian assets include the Boldman, Cobb, Kenova, and Kermit natural gas processing plants, the Siloam fractionation and propane storage facility, and a NGL pipeline.

In late 2007, we announced plans to significantly expand four of our five plants in the Appalachian region. The expansion includes replacing the existing Boldman and Cobb processing plants with cryogenic processing facilities. The new plants will increase the combined processing capacity at the two locations from 75 MMcf/d to 95 MMcf/d and will increase the NGL production capacity to over 180,000 gallons per day ("Gal/d") from 70,000 Gal/d currently. MarkWest will also modify the Kenova processing plant to improve propane recovery and increase production by approximately 10,000 Gal/d.

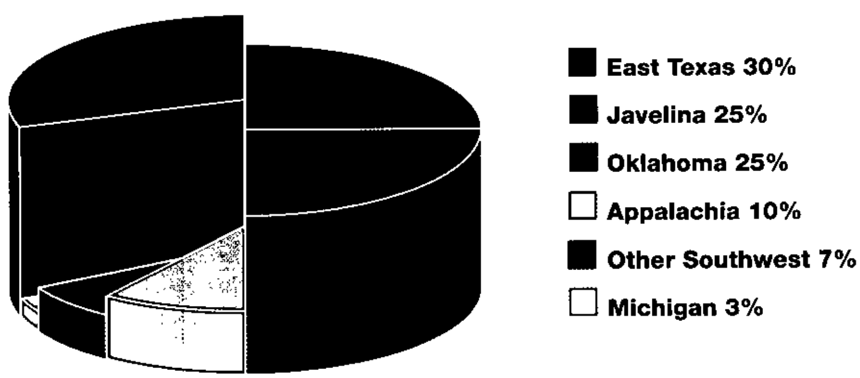
To accommodate the additional NGL production resulting from our processing plant expansions and from the increased horizontal drilling activity by major producer customers in the region, MarkWest is also expanding the fractionation capacity at Siloam to 900,000 Gal/d from the current 600,000 Gal/d.

We expect to complete the Kenova upgrade in mid-2008, the expansion of the Siloam facility in the third quarter of 2008, and the Boldman and Cobb expansions in early 2009. These expansions will result in a substantial increase in operating income and will allow us to continue serving the growing needs of the producers in this prolific basin.

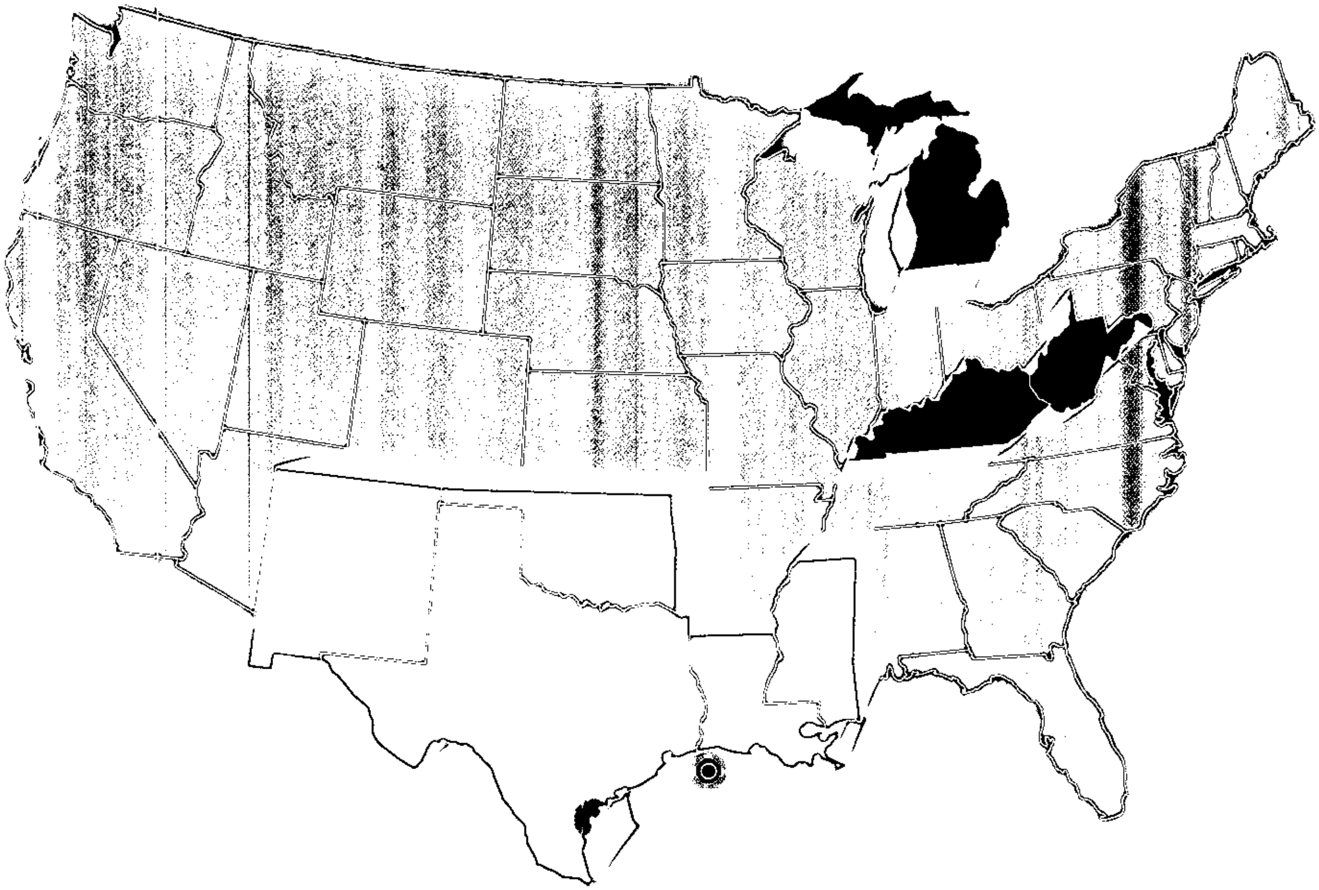
Michigan

We own and operate a crude oil pipeline in Michigan, which is subject to regulation by the Federal Energy Regulatory Commission. The pipeline is the largest crude oil gathering pipeline in Michigan supporting the production of our producer customers. The pipeline interconnects with a large downstream pipeline, which transports crude oil to several refineries in the Midwest region. We also own a natural gas gathering system and the Fisk processing plant in western Michigan.

Net Operating Margin by Segment



Map of Operations



☐ **Southwest Business Unit**

East Texas
- 440 MMcf/d gathering capacity
- 200 MMcf/d processing plant

Southeast Oklahoma
- 300 MMcf/d gathering capacity
- Centrahoma processing JV

Western Oklahoma
- 145 MMcf/d gathering capacity
- 100 MMcf/d processing plant

Other Southwest
- 12 gas gathering systems
- 4 lateral gas pipelines

■ **Gulf Coast Business Unit**

Javelina
- Gas processing, fractionation, and transportation facilities

Starfish (50% equity ownership)
- West Cameron dehydration facility
- 1.2 Bcf/d interstate pipeline

■ **Northeast Business Unit**

Appalachia
- Four processing plants with combined 295 MMcf/d processing capacity
- 600,000 Gal/d NGL fractionation facility
- 11 million gallon NGL storage facility
- 80-mile NGL pipeline

Michigan
- 250-mile interstate crude pipeline
- 90-mile gas gathering pipeline
- 35 MMcf/d gas processing plant

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, 2007.

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

1515 Arapahoe Street, Tower 2, Suite 700, Denver, CO 80202-2126
(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 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 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 definition of "large accelerated filer," "accelerated filer" and &!#od;''smaller reporting company'' in Rule 12b-2 of the Exchange Act. (Check one)

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 29, 2007 was approximately $1.1 billion.

As of February 28, 2008, the number of the registrant's common units were 50,876,295.

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 Shareholders to be held in 2008, 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 owned as of December 31, 2007.

As explained further in Part I, Item 1. Business, on February 21, 2008, MarkWest Energy Partners, L.P. closed its plan of redemption and merger (the "Merger") with MarkWest Hydrocarbon, Inc. (the "Company") and MWEP, L.L.C., a wholly owned subsidiary of the Partnership, pursuant to which the Company was merged into the Partnership.

This Annual Report on Form 10-K reflects amounts and events related prior to the consummation of the Merger and includes only the historical consolidated financial results of MarkWest Energy Partners, L.P. on a stand alone basis. The references made to the entities herein refer to those entities as they existed prior to the consummation of the Merger on February 21, 2008. The Partnership refers to MarkWest Energy Partners, L.P., prior to the consummation of the Merger, except where specifically noted. The Company refers to MarkWest Hydrocarbon, Inc., except where specifically noted.

Glossary of Terms

In addition, the following is a list of certain acronyms and terms used throughout the document:

Bbls	barrels
Bbl/d	barrels per day
Bcf	one billion cubic feet of natural gas
Btu	one British thermal unit, an energy measurement
Gal/d	gallons per day
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
MMcf	one million cubic feet of natural gas
MMcf/d	one million cubic feet of natural gas per day
MTBE	methyl tertieary butyl ether
Net operating margin (a non-GAAP financial measure)	revenues less purchased product costs
NGLs	natural gas liquids, such as propane, butanes and natural gasoline
NA	not applicable

Forward-Looking Statements

Statements included in this Annual Report on Form 10-K that are not historical facts are forward-looking statements. We use words such as "could," "may," "will," "predict", "should," "expect," "hope", "continue", "potential", "plan," "project," "anticipate," "believe," "estimate," "intend" and similar expressions to identify forward-looking statements.

These forward-looking statements are made based upon management's expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

PART I

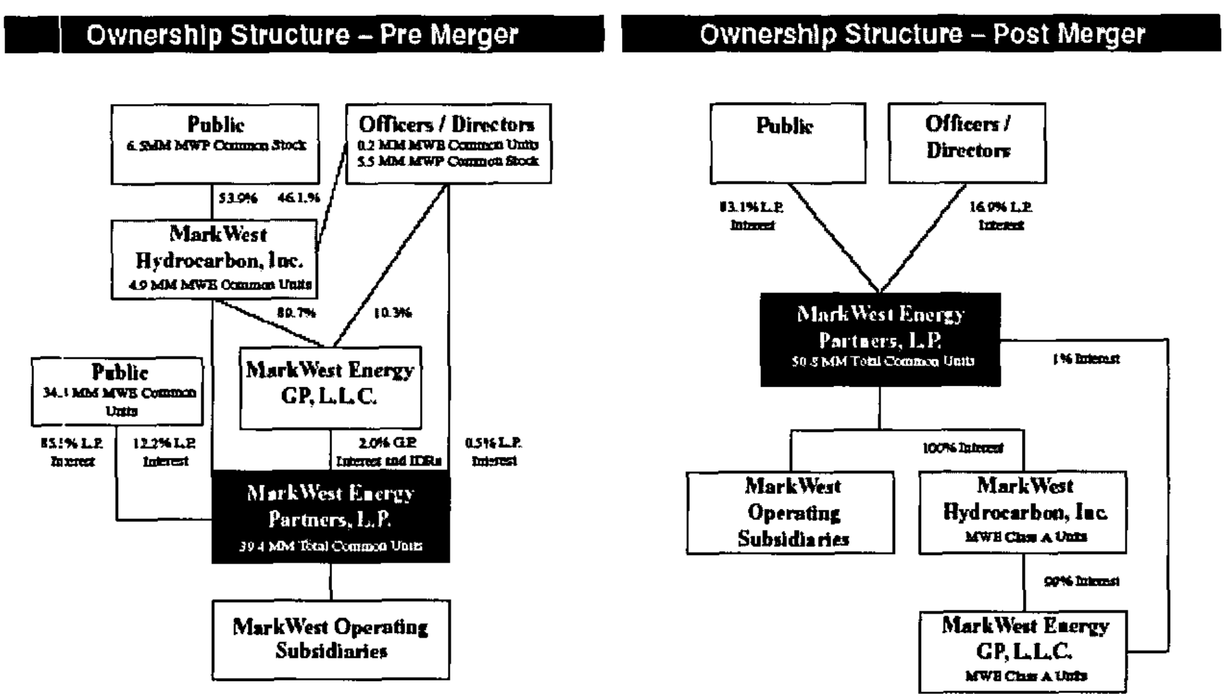
ITEM 1. Business

General

MarkWest Energy Partners, L.P. is a publicly traded Delaware limited partnership formed by MarkWest Hydrocarbon, Inc. on January 25, 2002, to acquire most of the assets, liabilities and operations of the MarkWest Hydrocarbon Midstream Business. We are a master limited partnership engaged in the gathering, transportation and processing of natural gas; the transportation, fractionation and storage of NGLs; and the gathering and transportation of crude oil. We conduct our operations in three geographical areas: the Southwest, the Northeast, and the Gulf Coast. For more information on these geographical areas, see the Business Strategy discussion below. Our common units are traded on the New York Stock Exchange under the symbol, "MWE." We are headquartered in Denver, Colorado, and more information about us can be found at our Internet website, *www.markwest.com*.

Recent Developments

On February 21, 2008, the Partnership consummated the transactions contemplated by its plan of redemption and merger with the Company and MWEP, L.L.C., a wholly owned subsidiary of the Partnership. Pursuant to this agreement, the Company redeemed for cash approximately 3.9 million shares of its common stock, which we refer to as the "redemption," followed immediately by a merger, pursuant to which all remaining shares of the Company common stock were converted into Partnership common units, which we refer to as the "merger." As a result of the merger, the Company is a wholly owned subsidiary of the Partnership. In connection with the merger and redemption, the incentive distribution rights in the Partnership, the 2% economic interest in the Partnership of MarkWest Energy GP, L.L.C. (the "General Partner") and the Partnership common units owned by the Company were exchanged for Partnership Class A Units. Contemporaneously with the closing of the transactions contemplated by the merger, the Partnership separately acquired 100% of the Class B membership interests in the General Partner that had been held by current and former management and certain directors of the Company and the General Partner for approximately $21.0 million in cash and 0.9 million Partnership common units. The Company paid to its stockholders approximately $240.5 million in cash in the redemption and the Partnership issued to the Company's stockholders approximately 15.5 million Partnership common units in the merger. As a result of the merger and redemption, the Company owns approximately 31% of the Partnership. Please refer to Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further information about the merger and redemption and related subsequent events. The following organization chart reflects the structure of the Partnership and Company both before and after the merger:



We expect the merger and redemption to offer the following advantages:

- eliminates the incentive distribution rights in the Partnership (see Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for information on the incentive distribution rights), which will substantially lower our cost of equity capital;
- enhances the Partnership's ability to compete for new acquisitions;
- improves the returns to the Partnership unitholders from the Partnership's expansion projects following the redemption and merger;
- will be accretive to the Partnership's distributable cash flow per common unit; and
- significantly reduces the costly duplication of services required to maintain two public companies.

The elimination of the incentive distribution rights increases available cash to be distributed to common unitholders. Please refer to "Distributions of Available Cash" in Part II, Item 5 of this Form 10-K for further information. In addition, the Partnership will also be able to distribute available cash from the Company after the Company pays taxes on its portion of the earnings from its ownership of the Partnership Class A Units. Despite the additional interest expense from borrowings needed to consummate the merger and redemption, we expect the cash available to distribute to common unitholders to increase in total and on a per common unit basis.

Business Strategy

Our primary business strategy is to grow our business and increase distributable cash flow per unit and maintain our financial strength, flexibility and our ability to access capital to fund our growth. We plan to accomplish this through the following:

- *Expanding operations through internal 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 2007, we spent approximately $308.7 million of growth capital to expand several of our gathering and processing operations. Projects included the initial construction of the Woodford gathering system in the Arkoma Basin in eastern Oklahoma, ongoing compressor expansions in East Texas, and well connection expansion projects in the Southwest Business Unit.
- *Increasing utilization of our facilities.* We hope to add to, or provide additional services to, our existing customers, and to provide services to other natural gas and crude oil producers in our areas of operation. Increased drilling activity in our core areas of operation, particularly within certain fields in the Southwest, should also produce increasing natural gas and crude oil supplies, and a corresponding increase in utilization of our transportation, gathering, processing and fractionation facilities. In the meantime, we continue to develop additional capacity at several of our facilities, which enables us to increase throughput with minimal incremental costs.
- *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 will also seek to acquire assets in certain regions outside of our current areas of operation.
- *Maintain our financial strength and flexibility.* As a publicly traded partnership, we have access to, and regularly utilize, both equity and debt capital markets as a source of financing, as well as that provided by our credit facility and the ability to use common units in connection with acquisitions. Our limited partnership structure also provides tax advantages to our unitholders.
- *Reducing the sensitivity of our cash flows to commodity price fluctuations.* We intend to continue to secure long-term, fee-based contracts in both our existing operations and strategic acquisitions, in order to further minimize our exposure to short-term changes in commodity prices.

The Partnership engages in risk management activities in order to reduce the effect of commodity price volatility related to future sales of natural gas, ethane, propane, butanes, natural gasoline and crude oil. It may utilize a combination of fixed-price forward contracts, fixed-for-floating price swaps, options available in the over-the-counter market, and futures contracts traded on the New York Mercantile Exchange. The Partnership monitors these activities through enforcement of our risk management policy. Please refer to Item 7A. Quantitative and Qualitative Disclosures About Market Risk—*Commodity Price Risk.*

Historically, we have generated revenues by providing gathering, processing, transportation, fractionation, and storage services. We believe that the largely fee-based nature of our business and the relatively long-term nature of our contracts provide a relatively stable base of cash flows.

We conduct our operations in three geographical areas: the Southwest, the Northeast and the Gulf Coast. We also have six segments which are based on geographic area of operation. Our assets and operations in each of these areas are described below.

Southwest Business Unit

- *East Texas.* We own the East Texas System, consisting of natural gas gathering system pipelines, centralized compressor stations, and a natural gas processing facility and NGL pipeline. The East Texas System is located in Panola, Harrison and Rusk Counties and services the Carthage Field, one of Texas' largest onshore natural gas fields. Producing formations in Panola County consist of the Cotton Valley, Pettit and Travis Peak formations, which together form one of the largest natural gas producing regions in the United States. For natural gas that is processed in this segment, we purchase the natural gas liquids from the producers primarily under percent-of-proceeds arrangements or fee-based arrangements. Approximately 90% of our natural gas volumes in the East Texas System result from contracts with five producers. The resulting NGLs and condensate make up approximately 85% of our revenues in the East Texas segment. We sell the purchased and retained NGLs to Targa Resources Partners, L.P. under a long-term contract. Such sales represent 31.8% of the Partnership's consolidated revenue in 2007.

- *Oklahoma.* We own the Foss Lake gathering system and the Arapaho gas processing plant, located in Roger Mills, Custer and Ellis counties of western Oklahoma. The gathering portion consists of a pipeline system that is connected to natural gas wells and associated compression facilities. All of the gathered gas ultimately is compressed and delivered to the processing plant. We also own a gathering system in the Woodford Shale play in the Arkoma Basin of southeastern Oklahoma, and we own the Grimes gathering system, which is located in Roger Mills and Beckham counties in western Oklahoma. Approximately 80% of our volumes are derived from gathering contracts; 20% from purchase agreements. Approximately two-thirds of our volumes result from contracts with three producers. The Oklahoma segment has three customers to which we sell NGLs, condensate and natural gas which account for a significant portion of its segment revenue. ONEOK, accounting for 14.8% of consolidated revenue in 2007, was also significant to the Partnership's consolidated revenues.

- *Other Southwest.* We own a number of natural gas-gathering systems located in Texas, Louisiana, Mississippi and New Mexico, including the Appleby gathering system in the City and County of Nacogdoches, Texas. We gather a significant portion of the gas produced from fields adjacent to our gathering systems. In many areas, we are the primary gatherer, and in some of the areas served by our smaller systems we are the sole gatherer. In addition, we own four lateral pipelines in Texas and New Mexico. The Other Southwest segment does not have any customers which we consider to be significant to this segment's revenues. A significant portion of the net operating margin (as defined in *Our Contracts* below) in 2007 for the Other Southwest results from contracts with five customers.

Northeast Business Unit

- *Appalachia.* We are one of the largest processors of natural gas in the Appalachian Basin with fully integrated processing, fractionation, storage and marketing operations. The Appalachian Basin is a large natural gas producing region characterized by long-lived reserves and modest decline rates. Our Appalachian assets include the Kenova, Boldman, Cobb and Kermit natural gas-processing plants, an NGL pipeline, an NGL fractionation plant and two caverns for storing propane. The Appalachia segment has one customer which accounts for a significant portion of its segment revenue but does not account for a significant portion of the Partnership's consolidated revenue.

- *Michigan.* We own and operate a crude oil pipeline in Michigan, which we refer to as the Michigan Crude Pipeline. The Michigan Crude Pipeline is subject to regulation by the Federal Energy Regulatory Commission ("FERC"). We also own a natural gas-gathering system and the Fisk processing plant in Manistee County, Michigan. The Michigan segment does not have any single customer which is considered to be significant to its segment revenue.

Gulf Coast Business Unit

- *Javelina.* We own and operate the Javelina Processing Facility, a natural gas processing facility in Corpus Christi, Texas, which treats and processes off-gas from six local refineries. The facility processes approximately 125 to 130 MMcf/d of inlet gas out of its 142 MMcf/d capacity. The Gulf Coast segment has five customers which account for a significant portion of its segment revenue but do not account for a significant portion of the Partnership's consolidated revenue.

We own a 50% non-operating membership interest in Starfish, whose assets are located in the Gulf of Mexico and southwestern Louisiana. The Starfish interest is part of a joint venture with Enbridge Offshore Pipelines LLC, which is accounted for using the equity method; the financial results for Starfish are included in equity from earnings (losses) from unconsolidated affiliates and are not included in the Gulf Coast Business Unit results. Starfish owns the FERC-regulated Stingray natural gas pipeline, and the unregulated Triton natural gas gathering system and West Cameron dehydration facility. All of the assets are located in the Gulf of Mexico and southwestern Louisiana.

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

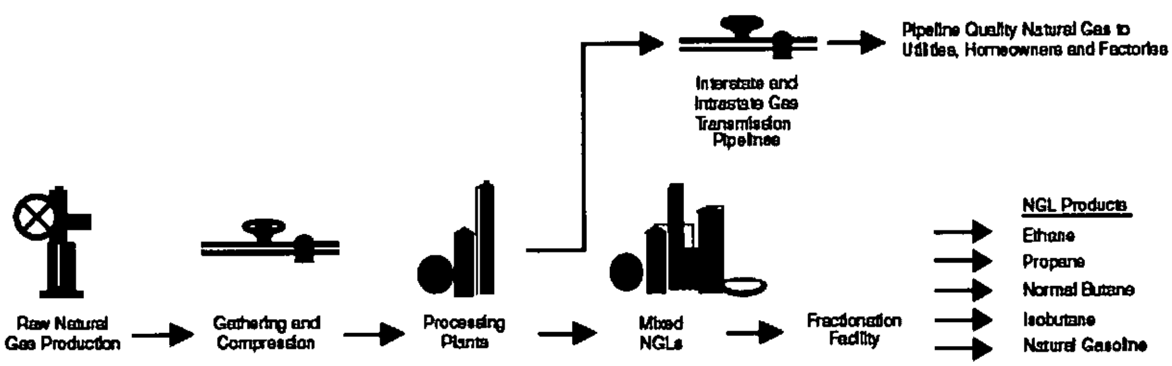
The following summarizes the percentage of our revenue and net operating margin (a non-GAAP financial measure, see *Our Contracts* discussion below) generated by our assets, by geographic region, for the year ended December 31, 2007:

	East Texas	Oklahoma	Other Southwest	Appalachia	Michigan	Gulf Coast
Revenue	31%	34%	10%	11%	2%	12%
Net operating margin	30%	25%	7%	10%	3%	25%

MarkWest Hydrocarbon was founded in 1988 as a partnership and later incorporated in Delaware. MarkWest Hydrocarbon is an energy company primarily focused on marketing NGLs. MarkWest Hydrocarbon's assets consist primarily of partnership interests in MarkWest Energy Partners and certain processing agreements in Appalachia.

Industry Overview, Competition

MarkWest Energy Partners provides services in most areas of the natural gas gathering, processing and fractionation industry. The following diagram illustrates the typical natural gas gathering, processing and fractionation process:

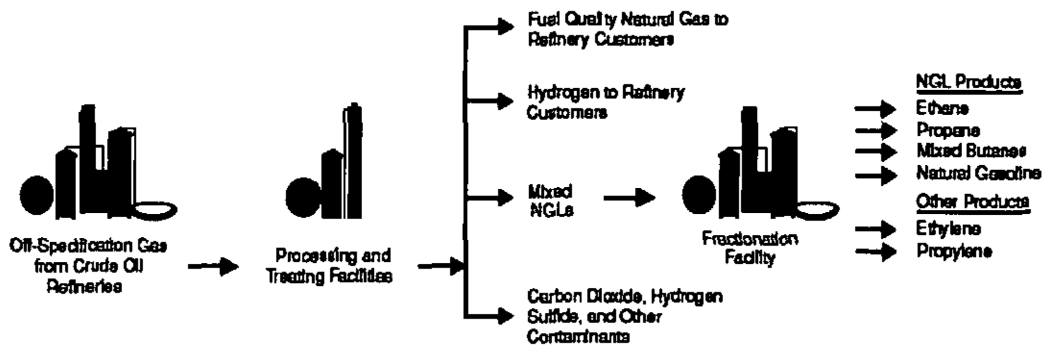


The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once completed, the well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems, that collect natural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

Natural gas has a widely varying composition, depending on the field, the formation reservoir or facility from which it is produced. The principal constituents of natural gas are methane and ethane. Most 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 then processed to remove the heavier hydrocarbon components and other contaminants that 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.

MarkWest Energy also provides processing and fractionation services to crude oil refineries in the Corpus Christi, Texas, area through its Javelina Gas Processing and Fractionation facility. While similar to the natural gas industry diagram outlined above, the following diagram illustrates the significant gas processing and fractionation processes at the Javelina Facility:



Natural gas processing and treating involves the separation of raw natural gas into pipeline-quality natural gas, principally methane, and NGLs, as well as the removal of contaminants. Raw natural gas from the wellhead is gathered at a processing plant, typically located near the production area, where it is dehydrated and treated, and then processed to recover a mixed NGL stream. In the case of our Javelina facilities, the natural gas delivered to our processing plant is a byproduct of the crude oil refining process.

The removal and separation of individual hydrocarbons 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. We also produce a high quality hydrogen stream that is delivered back to certain refinery customers.

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.

Described below are the five basic NGL products and their typical uses:

- *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 produced at our Siloam fractionator, as there is little petrochemical demand for ethane in Appalachia. It remains, therefore, in the natural gas stream. Ethane, however, is produced and sold in our East Texas, Gulf Coast and Oklahoma operations.

- *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 principally 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 principally 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.

We face competition for natural gas and crude oil transportation and in obtaining natural gas supplies for our processing and related services operations; in obtaining unprocessed NGLs for 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 is based primarily on price, delivery capabilities, flexibility and maintenance of high-quality customer relationships.

Our competitors include:

- other large natural gas gatherers that gather, process and market natural gas and NGLs;

- major integrated oil companies;

- medium and large sized independent exploration and production companies;

- major interstate and intrastate pipelines; and

- a large number of smaller gas gatherers of varying financial resources and experience.

Many of our competitors operate as master limited partnerships and 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 control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas.

We believe our competitive strengths include:

- *Strategic and growing position with high-quality assets in the Southwest and the Gulf Coast.* Our acquisitions and internal growth projects have allowed us to establish and expand our presence in several long-lived natural gas supply basins in the Southwest, particularly in Texas and Oklahoma. In late 2006, we began expanding this strategy through our Newfield agreement by building the largest gathering system to date in the newly emerging Woodford Shale play in southeastern Oklahoma. Our Gulf Coast assets provide high quality service to six strategically located gulf coast refineries that we believe will continue to play a key role in supporting US demand for refined petroleum products in the long term. All of our major acquisitions in these regions 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 acquisition or expansion opportunities.

Specifically, our East Texas and Appleby gathering systems are located in the East Texas basin producing from both the Cotton Valley and Travis Peak reservoirs. Our Foss Lake gathering system and the associated Arapaho gas processing plant are located in the Anadarko basin in Oklahoma. Additionally, as mentioned above, our Woodford gathering system is located in the rapidly growing Woodford shale reservoir. We refer to our Foss Lake gathering system, the Arapaho Plant and the Woodford gathering system as our Oklahoma assets. Finally, our Starfish asset gathers gas from multiple reservoirs in the Gulf of Mexico. Each of these basins are highly prolific with long lived reserves and significant growth potential. 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 believe this competitive advantage is evidenced by our growing throughput volumes in our East Texas, Appleby, and Oklahoma operations.

- *Leading position in the Appalachian Basin.* We are one of the largest processors of natural gas in Appalachia. We believe our significant presence and asset base provide us with a competitive advantage in capturing and contracting for new supplies of natural gas. The Appalachian Basin is a large natural gas-producing region characterized by long-lived reserves with modest decline rates and natural gas with high NGL content. These reserves provide a stable supply of natural gas for our processing plants and our Siloam NGL fractionation facility. Our concentrated infrastructure, and available land, storage assets and expansion plans in Appalachia should continue to provide us with a platform for additional cost-effective expansion. In November 2007, the Partnership announced a plan to invest approximately $60.0 million to significantly expand nearly all of its plants in the Appalachia region. The Partnership expects to complete the Kenova upgrade in early 2008, the expansion of the Siloam facility in the third quarter of 2008, and the Boldman and Cobb expansions in early 2009.

- *Stable cash flows.* We believe our numerous fee-based contracts and our active commodity risk management program provide us with stable cash flows. For the year ended December 31, 2007, we generated approximately 32% of our net operating margin (a non-GAAP financial measure, see *Our Contracts* discussion below) from fee-based services. In addition, a portion of our fee-based business is generated by our four lateral pipelines in the Southwest, which typically provide fixed transportation fees independent of the volumes transported. We also believe that an active commodity risk management program is a significant component of providing stable cash flows as our commodity exposure grows with our expanding operations.

- *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. In East Texas, approximately 77% of our current gathering volumes as of December 31, 2007, are under contract for longer than four years. Two of our Pinnacle lateral pipelines operate under fixed-fee contracts for the transmission of natural gas that expire in approximately 15 and 23 years, respectively. Approximately 20% of our daily throughput in the Foss Lake gathering system and Arapaho processing plant in western Oklahoma is subject to contracts with remaining terms of four years or more. The majority of our throughput in the Woodford gathering system is subject to contracts with remaining terms of more than 12 years. In Appalachia, we have natural gas processing and NGL fractionation contracts with remaining terms from 4 to 6 years. In Michigan, our natural gas transportation, treating and processing agreements have remaining terms of 9 to 21 years.

- *Experienced management with operational, technical and acquisition expertise.* Each member of our executive management team has substantial experience in the energy industry. Our facility managers have extensive experience operating our facilities. Our operational and technical expertise has enabled us to upgrade our existing facilities, as well as to design and build new ones. 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 nine acquisitions. We intend to continue to use our management's experience and disciplined approach in evaluating and acquiring assets to grow through accretive acquisitions—those acquisitions expected to increase our throughput volumes and cash flow distributable to our unitholders.

- *Financial strength and flexibility.* During 2007, we issued approximately $229.6 million of equity. Our goal is to maintain a capital structure with approximately equal amounts of debt and equity on a long-term basis. We expect the merger and redemption will substantially lower our cost of equity capital.

As of February 25, 2008, we have available borrowing capacity of approximately $258.5 million under our new $350.0 million revolving credit facility. See further discussion of our new credit facility in Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K. The borrowing capacity is determined on a quarterly basis and is further adjusted to take into consideration the cash flow contribution of an acquisition at the time of its closing. The credit facility, together with our ability to issue additional partnership units for financing and acquisition purposes, should provide us with a flexible financial structure that will facilitate the execution of our business strategy.

To better understand our business and the results of operations discussed in Item 6. Selected Financial Data and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation, the following two factors are important to consider:

- the nature of the contracts from which we derive our revenues; and

- the difficulty in comparing our results of operations across periods because of our acquisition activity.

Our Contracts

We generate the majority of our revenues and net operating margin (a non-GAAP measure, see below for discussion and reconciliation of net operating margin) from natural gas gathering, processing and transmission; NGL transportation, fractionation 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 different types of arrangements (all of which constitute midstream energy operations):

- *Fee-based arrangements:* Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, processing and transmission of natural gas; transportation, fractionation and storage of NGLs; and gathering and transportation of crude oil. The revenue we earn from these arrangements is 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. In certain cases, our arrangements provide for minimum annual payments or fixed demand charges. If a sustained decline in commodity prices were to result in a decline in volumes, however, our revenues from these arrangements would be reduced.

- *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 based on an index price. 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. Generally, under these types of arrangements our revenues and gross 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 (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. 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 (1) and (3) 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 from the producer, process the natural gas and sell 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, 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. 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.

- *Settlement margin:* Typically, 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 our gathering systems are operated more efficiently than specified per contract allowance, we are entitled to retain the difference 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. Any change in mix will influence our financial results.

As of December 31, 2007, our primary exposure to keep-whole contracts was limited to our Arapaho (Oklahoma) processing plant and our East Texas processing contracts. At the Arapaho plant inlet, the Btu content of the natural gas meets the downstream pipeline specification; however, we have the option of extracting NGLs when the processing margin environment is favorable. Due to our ability to operate the Arapaho plant in several recovery modes, our overall keep-whole contract exposure is limited to a small portion of the operating costs of the plant.

Approximately 11% of the gas processed in East Texas for producers was processed under keep-whole terms. Our keep-whole exposure in this area was offset to a great extent because the East Texas agreements provide for the retention of natural gas as a part of the gathering and compression arrangements with all producers on the system. This excess gas helps offset the amount of replacement natural gas purchases required to keep our producers whole on an MMbtu basis, thereby creating a partial natural hedge. The net result is a significant reduction in volatility for these changes in natural gas prices. The remaining volatility for these contracts results from changes in NGL prices. We have an active commodity risk management program in place to reduce the impacts of changing NGL prices.

Management evaluates contract performance on the basis of net operating margin (a non-GAAP financial measure), which is defined as income (loss) from operations, excluding facility expense, selling, general and administrative expense, depreciation, amortization, impairments and accretion of asset retirement obligations. 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 usage 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 to income from operations, the most comparable GAAP financial measure of this non-GAAP financial measure (in thousands):

	Year ended December 31,		
	2007	2006	2005
Revenues	$602,879	$629,911	$541,090
Purchased product costs	358,720	376,237	408,884
Net operating margin	244,159	253,674	132,206
Facility expenses	75,036	60,112	47,972
Selling, general and administrative	51,334	44,377	21,597
Depreciation	40,171	29,993	19,534
Amortization of intangible	16,672	16,047	9,656
Loss (gain) on disposal of property, plant and equipment	7,564	(192)	(24)
Accretion of asset retirement obligation	114	102	159
Impairments	356	—	—
Income from operations	$52,912	$103,235	$33,312

For the year ended December 31, 2007, we calculated the following approximate percentages of our revenues and net operating margin from the following types of contracts:

	Fee-Based	Percent-of-Proceeds(1)	Percent-of-Index(2)	Keep-Whole(3)
Revenue	15%	38%	28%	19%
Net operating margin	32%	41%	7%	20%

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

(2) Includes settlement margin, condensate sales and other types of arrangements tied to natural gas prices.

(3) Includes settlement margin, condensate sales and other types of arrangements tied to both NGL and natural gas prices.

Our short natural gas positions under our keep-whole contracts are largely offset by our long positions in our other operating areas. As a result, our net exposure to natural gas price volatility is not significant prior to the merger. While the percentages in the table above accurately reflect the percentages by contract type, we manage our business by taking into account the offset described above, required levels of operational flexibility and the fact that our hedge plan is implemented on this basis. When considered on this basis, the calculated percentages for the net operating margin in the table above for Percent-of-Proceeds, Percent-of-Index and Keep-Whole contracts change to 61%, 0% and 7%, respectively. As a result of our acquisition of MarkWest Hydrocarbon and its NGL marketing business, our exposure to keep-whole contracts will increase and as a result our exposure to natural gas volatility will increase as well. For further information on our natural gas volatility, please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk—*Commodity Price Risk* as set forth in this report.

Acquisitions

A significant part of our business strategy includes acquiring additional businesses and assets that will allow us to increase distributions to our unitholders. We regularly consider and enter into discussions regarding potential acquisitions. These transactions may be effectuated quickly, may occur at any time and may be significant in size relative to our existing assets and operations.

Since our initial public offering, we have completed nine acquisitions for an aggregate purchase price of approximately $810 million, net of working capital. The acquisitions were individually accounted for as a business combination. Summary information regarding each of these acquisitions is presented below (consideration in millions):

Name	Assets	Location	Consideration	Closing Date
Santa Fe	Gathering system	Oklahoma	$15.0	December 29, 2006
Javelina(1)	Gas processing and fractionation facility	Corpus Christi, TX	398.8	November 1, 2005
Starfish(2)	Natural gas pipeline, gathering system and dehydration facility	Gulf of Mexico/ Southern Louisiana	41.7	March 31, 2005
East Texas	Gathering system and gas processing assets	East Texas	240.7	July 30, 2004
Hobbs	Natural gas pipeline	New Mexico	2.3	April 1, 2004
Michigan Crude Pipeline	Common carrier crude oil pipeline	Michigan	21.3	December 18, 2003
Western Oklahoma	Gathering system	Western Oklahoma	38.0	December 1, 2003
Lubbock Pipeline	Natural gas pipeline	West Texas	12.2	September 2, 2003
Pinnacle	Natural gas pipelines and gathering systems	East Texas	39.9	March 28, 2003

(1) Consideration includes $35.5 million in cash.

(2) Represents a 50% non-controlling interest.

Regulatory Matters

Our operations are subject to extensive regulations. The failure to comply with applicable laws and regulations can result in substantial penalties. 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.

Pipeline and Gathering Regulation

Interstate Gas Pipelines. Our natural gas pipeline operations are subject to federal, state and local regulatory authorities. Specifically, our Hobbs, New Mexico natural gas pipeline, our proposed Arkoma Connector natural gas pipeline in Oklahoma, and our Michigan crude oil pipeline facilities and related assets are subject to regulation by the FERC. In addition, the Midcontinent Express Pipeline connecting Bennington, Oklahoma, and Perryville, Louisiana, in which we have an option to acquire a 10% interest, will also be subject to regulation by the FERC. Federal regulation extends to such matters as:

- rate structures;
- return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; 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 natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. 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 assure you that FERC will continue to pursue its approach of procompetitive 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 EP Act"). Under the 2005 EP Act, FERC may impose civil penalties of up to $1,000,000 per day for each current violation of the NGA or the Natural Gas Policy Act of 1978. The 2005 EP Act 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 EP Act. This order makes it unlawful for gas pipelines and storage companies that provide interstate services to: (1) 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, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to 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. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot assure you that present policies pursued by FERC and Congress will continue.

Affiliate Relationships. Commencing in 2003, FERC issued a series of orders adopting rules for new Standards of Conduct for Transmission Providers (Order No. 2004) that applied to interstate natural gas pipelines and to certain natural gas storage companies, which provide storage services in interstate commerce. Among other matters, Order No. 2004 required interstate pipelines to operate independently from their energy affiliates, prohibited interstate pipelines from providing non-public transportation or shipper information to their energy affiliates, prohibited interstate pipelines from favoring their energy affiliates in providing service, and obligated interstate pipelines to post on their websites a number of items of information concerning the company, including its organizational structure, facilities shared with energy affiliates, discounts given for service and instances in which the company has agreed to waive discretionary terms of its tariff.

The United States Court of Appeals for the District of Columbia Circuit vacated and remanded Order No. 2004 in late 2006, as it relates to natural gas transportation providers. On January 9, 2007, and as clarified on March 21, 2007, FERC issued an interim rule re-promulgating on an interim basis the standards of conduct that were not challenged before the court. The interim rule makes the standards of conduct apply to the relationship between natural gas transportation providers and their marketing affiliates, but not to energy affiliates who are not also marketing affiliates. FERC has now issued a notice of proposed rulemaking ("NOPR") that proposes permanent standards of conduct which FERC states will avoid the aspects of the previous standards of conduct rejected by the court. We have no way to predict with certainty the scope of FERC's permanent rules on the standards of conduct.

Market Transparency Rulemakings. In 2007, FERC issued a NOPR on pipeline posting requirements and a final rule on annual natural gas transaction reporting (Order 704). Under Order No. 704, wholesale buyers and sellers of more than a minimum volume of natural gas are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with the Commission's Policy Statement on price reporting. Several parties have filed requests for clarification or rehearing that are currently pending before FERC.

Under the NOPR on pipeline posting requirements, the Commission is proposing to require intrastate pipelines to post daily actual and scheduled flows on an Internet website. It is also proposing to require that interstate pipelines add actual daily volumes to their Internet websites. We cannot predict the ultimate impact of these regulatory changes to our natural gas operations. We do not believe we would be affected by any such FERC action materially different than any other natural gas company with which we compete.

Gathering and Intrastate Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We own a number of facilities that we believe meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. 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. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes 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. These statutes 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. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our 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 at 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.

Our Appalachian pipeline carries NGLs across state lines. The primary shipper on the pipeline is MarkWest Hydrocarbon, which has entered into agreements with us providing for a fixed transportation charge for the term of the agreements. They expire on December 31, 2015. We are the only other shipper on the pipeline. We neither operate our Appalachian pipeline as a common carrier, nor hold it out for service to the public. Generally, there are currently no third-party shippers on this pipeline and the pipeline is, and will continue to be, operated as a proprietary facility. The likelihood of other entities seeking to utilize our Appalachian pipeline is remote, so it should not be subject to regulation by the FERC in the future. We cannot provide assurance, however, that FERC will not at some point determine that such transportation 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 and provide a cost justification for the transportation charge.

Crude Common Carrier Pipeline Operations. Our Michigan Crude Pipeline is a crude oil pipeline that is a common carrier and subject to regulation by the 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 the 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 tariffs to be maintained on file with the FERC that set forth the rates it charges for providing transportation services on its interstate common carrier liquids pipelines as well as 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. In addition, the FERC retains cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach.

With respect to our Michigan Crude Pipeline, we filed a tariff establishing a cost-of-service rate structure to be effective starting January 1, 2006, and pursuant to a FERC certified settlement with shippers on the pipeline, the rate structure is under a moratorium on rate changes or challenges for a three-year period, with limited exceptions.

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, 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, restricting the manner in which we handle or dispose of our wastes, limiting or prohibiting activities in sensitive areas such as wetlands, ecologically-sensitive areas, or areas inhabited by endangered species, incurring capital costs to construct, maintain and upgrade equipment 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 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 that 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 ensure, however, that existing environmental laws and regulations will not be revised or that new laws and regulations will not be adopted or become applicable to us. The clear trend in environmental law is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental-regulation compliance or remediation, 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 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.

Hazardous Substance and Waste.

To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control environmental 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 that contributed to a release of "hazardous substance" into the environment. These persons include current and prior owners or operators of a site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of removing or remediating hazardous substances that have been released into the environment, for restoration 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 regulated as hazardous substances under CERCLA or similar state statutes, we have not received any notification that we may be potentially responsible for cleanup costs under such laws. 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 hazardous wastes and nonhazardous solid wastes. We are not currently required to comply with a substantial portion of the RCRA requirements 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 may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements.

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 and processing, for NGL fractionation, transportation and storage or for the storage and gathering and transportation of crude oil. Although solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years, a possibility exists that hydrocarbons and other solid 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 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 hydrocarbons or other solid wastes for which we are currently responsible. We do not believe that there presently exists significant surface and subsurface contamination of our properties by hydrocarbons or other solid wastes for which we are currently responsible.

Ongoing Remediation and Indemnification from a Third Party.

The previous owner/operator of our Boldman and Cobb facilities 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 an "Agreed Order" entered into by the previous owner/operator with the Kentucky Natural Resources and Environmental Protection Cabinet in October 1994. The previous owner/operator has accepted sole liability and responsibility for, and indemnifies MarkWest Hydrocarbon 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 MarkWest Hydrocarbon's lease or purchase of the real property. In addition, the previous owner/operator has agreed to perform all the required response actions at its expense in a manner that minimizes interference with MarkWest Hydrocarbon's use of the properties. On May 24, 2002, MarkWest Hydrocarbon assigned to us the benefit of this indemnity from the previous owner/operator. To date, the previous owner/operator has been performing all actions required under these agreements 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. To date, the previous owner/operator has been performing all actions required under these agreements 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.

Air.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, 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, or utilize specific equipment or technologies to control emissions. As the result of changes to the Clean Air Act, we may be required to incur certain capital expenditures for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission-related issues. We do not believe, however, that such requirements will have a material adverse affect on our operations.

Water.

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. In addition, the Clean Water Act and analogous state law require individual permits or coverage under general permits for discharges of stormwater from certain types of facilities. These permits may require us to monitor and sample the stormwater runoff. Any unpermitted release of pollutants, including oil, natural gas liquids or condensates, could result in penalties, as well as significant remedial obligations. We believe that we are in substantial compliance with the Clean Water Act.

Global Warming and Climate Control.

Some scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases, which may include the implementation of emissions allowances that could be traded or acquired in the open market. This legislation may be subject to debate and a possible vote by mid-year 2008. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

Anti-Terrorism Measures.

Our operations and the operations of the natural gas and oil industry in general may be subject to laws and regulations regarding the security of industrial facilities, including natural gas and oil facilities. The Department of Homeland Security Appropriations Act of 2007 required the Department of Homeland Security ("DHS"), to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule, known as the Chemical Facility Anti-Terrorism Standards interim rule, in April 2007 regarding risk-based performance standards to be attained pursuant to the act and on November 20, 2007 further issued an Appendix A to the interim rule that established the chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. In January 2008, we prepared and submitted to the DHS initial screening surveys for facilities operated by us that possess regulated chemicals of interest in excess of the Appendix A threshold levels. Because we are currently awaiting a response from DHS on the extent to which some or all of our surveyed facilities may be determined to present a high level of security risk, the associated costs for complying with this interim rule has not been determined by us, and it is possible that such costs ultimately could be substantial.

Pipeline Safety Regulations

Our pipelines are subject to regulation by the U.S. Department of Transportation ("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, due to the possibility of new or amended laws and regulations or re interpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

Our pipelines are also subject to regulation by the DOT under the Pipeline Safety Improvement Act of 2002, which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The DOT, through the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), has established a series of rules 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 is required by the Pipeline Inspections, Protection, Enforcement, and Safety Act of 2006 to issue new regulations that set forth safety standards and reporting requirements applicable to low stress pipelines and gathering lines transporting hazardous liquids, including oil, NGLs and condensate. A final rule addressing safety standards for hazardous liquid low-stress pipelines and gathering lines is anticipated to be issued by PHMSA in 2008. Such new hazardous liquid pipeline safety standards may include applicable integrity management program requirements. 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.

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

We employ through our subsidiary, MarkWest Hydrocarbon, Inc., 356 individuals to operate our facilities and provide general and administrative services. The Paper, Allied Industrial, Chemical and Energy Workers International Union Local 5-372 represents 15 employees at our Siloam fractionation facility in South Shore, Kentucky. The collective bargaining agreement with this union was renewed on July 11, 2005, for a term of three years. The agreement covers only hourly, non-supervisory employees. We consider labor relations to be satisfactory at this time.

Available Information

Our principal executive office is located at 1515 Arapahoe Street, Tower 2, Suite 700, Denver, Colorado 80202-2126. 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 through our Internet website as soon as reasonably practicable after we electronically file or furnish such material with the Securities & Exchange Commission.

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 MarkWest Energy Partners.

Risks Inherent in Our Business

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 units depends principally on the amount of cash we generate from our operations, which will 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 volumes of natural gas we gather, process and transport;
- the level of our operating costs, including reimbursement of fees and expenses of our general partner; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will 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;
- 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 for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

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

One of the ways we intend to grow our business is through the construction of additions to our existing gathering systems and construction of new gathering, processing and treating facilities. The construction of gathering, processing 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. If we undertake these projects, we may not be able to complete them on schedule or at all or at the budgeted cost. 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 will occur over an extended period of time, and we will not receive any material increases in revenues until after completion of the project, if at all.

Furthermore, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. 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 to achieve our expected investment return, 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 (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to increase distributions will 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 will 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 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 will consider in determining the application of these funds and other resources.

Our acquisition strategy is based in part on our expectation of ongoing divestitures of assets within the midstream petroleum and natural gas industry. A material decrease in such divestitures could limit our opportunities for future acquisitions, and could adversely affect our operations and cash flows available for distribution to our unitholders.

Our substantial debt and other financial obligations could impair our financial condition, results of operations and cash flows, 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 a future downturn in our business or the economy in general, conduct operations or otherwise take advantage of business opportunities that may arise. Our existing credit facility contains covenants requiring us to maintain specified financial ratios and satisfy other financial conditions, which, if not maintained, 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 the credit facility, make distributions on equity investments, and declare or make, directly or indirectly, any distribution on our common units. Our obligations under the credit facility are secured by substantially all of our assets and guaranteed by all of our subsidiaries, other than our operating company, which is the borrower under the credit facility (please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—*Liquidity and Capital Resources*). In particular, we may be unable to meet those ratios and conditions. 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, 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.

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 and our treating 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, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital. 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. Declines in natural gas prices, if sustained, could lead to a material decrease in such production activity and ultimately to a decrease in exploration activity.

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 treating and processing 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 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.

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, if third parties do not renew or extend their contracts with us or if any third party suspends or terminates its contracts with us, our financial results would suffer.

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

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—*Overview* of Part 1 of this report.

Our profitability is 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 2005 ranged from a high of $15.38 per MMBtu to a low of $5.79 per MMBtu. In 2006, the same index ranged from a high of $10.63 per MMBtu to a low of $4.20 per MMBtu. In 2007, the same index ranged from a high of $8.64 per MMBtu to a low of $5.38 per MMBtu. A composite of the weighted monthly average NGLs price at our Appalachian facilities based on our average NGLs composition in 2005 ranged from a high of approximately $1.31 per gallon to a low of $0.79 per gallon. In 2006, the same composite ranged from approximately $1.29 per gallon to approximately $0.99 per gallon. In 2007, the same composite ranged from approximately $1.76 per gallon to approximately $0.96 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;
- imports of crude oil, natural gas and NGLs;
- seasonality;
- 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.

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

Under the Partnership's keep-whole arrangements, its 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.

Due to timing of gas purchases and liquid sales, direct exposure to either gas or liquids can be created because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Through the Partnership's marketing and derivatives activity, direct exposure may occur naturally or the Partnership may choose direct exposure to either gas or liquids when the Partnership favors that exposure over frac spread risk. Given that the Partnership has positions, adverse movement in prices to the positions the Partnership has taken will 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 will continue to have direct commodity price exposure to the unhedged portion. 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 satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging 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 hedging 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 hedging 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 Item 7A. Quantitative and Qualitative Disclosures About Market Risk—*Commodity Price Risk* as set forth in this report.

Management of the General Partner has discretion in conducting our risk management activities and may not accurately predict future 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. Management of the General Partner has 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.

Changes in commodity prices subject us to margin calls, which may adversely affect our liquidity.

Unfavorable commodity price changes may subject us to margin calls that require us to provide letter of credit collateral to our counterparties in amounts that may be material. Such funding requirements could exceed our letter of credit availability on our credit line. If we were unable to meet these margin calls with letters of credit, we would be forced to sell product to meet the margin calls, or to terminate the corresponding futures contracts. If we are forced to sell product to meet margin calls, we may have to sell product at prices that are not advantageous, which could adversely affect our operations and cash flows available for distribution to our unitholders.

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 out unitholders.

Some of our gas, liquids and crude oil transmission operations are subject to rate and service regulations under FERC or various state regulatory bodies, depending upon jurisdiction. FERC generally regulates the transportation of natural gas and oil in interstate commerce, and FERC's regulatory authority includes: facilities construction, acquisition, extension or abandonment of services or facilities; accounts and records; and depreciation and amortization policies. Intrastate natural gas pipeline operations and transportation on proprietary natural gas or petroleum products pipelines are generally not subject to regulation by FERC, and the Natural Gas Act, which is referred to as "NGA," specifically exempts some gathering systems. 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. We cannot assure unitholders that FERC will not at some point determine that such gathering and transportation services are within its jurisdiction, and regulate such services. 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.

If we are unable to obtain new rights-of-way or the cost of renewing existing rights-of-way 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 may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way 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 our facilities are located and our results of operation and our ability to make distributions to our unitholders could be adversely affected if the indemnifying party fails to perform its indemnification obligation.

Columbia Gas is the previous or current owner of the property on which our Kenova, Boldman, Cobb and Kermit facilities are located and is the previous operator of our Boldman and Cobb facilities. Columbia Gas has been or is currently involved in investigatory or remedial activities with respect to the real property underlying the Boldman and Cobb 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 MarkWest Hydrocarbon 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. At the closing of our initial public offering, MarkWest Hydrocarbon assigned us the benefit of its indemnity from Columbia Gas with respect to the Cobb, Boldman and Kermit facilities. While we are not a party to the agreement under which Columbia Gas agreed to indemnify MarkWest Hydrocarbon with respect to the Kenova facility, MarkWest Hydrocarbon has agreed to provide to us the benefit of its indemnity, as well as any other third party environmental indemnity of which it is a beneficiary. 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 MarkWest Hydrocarbon fails to perform under the indemnification provisions of which we are the beneficiary.

Our business is subject to federal, state and local laws and regulations with respect to environmental, safety 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, local and state laws and regulations on a wide range of environmental, safety 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. Joint and several strict 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 the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Resource Conservation and Recovery Act, as amended, 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 might adversely influence our products and activities. Federal, state and local agencies also could impose additional safety requirements, any of which could affect our profitability. In addition, we face the risk of accidental releases or spills associated with our operations. These could result in material costs and liabilities, including those relating to claims for damages to property, natural resources and persons. Our failure to comply 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 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.

The amount of gas we process, gather and transmit, or the crude oil we gather and transport, may be reduced if the pipelines to which we deliver the natural gas or crude oil cannot, or will not, accept the gas 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, we will 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 facilities. Likewise, if the pipelines into which we deliver crude oil are interrupted, we will be limited in, or prevented from conducting, our crude oil 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 pipeline. Because our revenues and net operating margins depend upon (1) the volumes of natural gas we process, gather and transmit, (2) the throughput of NGLs through our transportation, fractionation and storage facilities and (3) 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.

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, and various means of transportation. Any significant interruption at these facilities or pipelines, or our inability to transmit natural gas or NGLs, or transport crude oil to or from these facilities or pipelines for any reason, 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;
- labor difficulties that result in a work stoppage or slowdown; and
- 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 transportation pipeline and fractionation facility.

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, the market price of the common units is likely to decline.

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;
- inadvertent damage from construction and farm equipment;
- leakage of crude oil, natural gas, NGLs and other hydrocarbons;
- fires and explosions; and
- other hazards, including those associated with high-sulfur content, or sour gas 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.

As a result of damage caused by Hurricanes Katrina and Rita in the Gulf of Mexico and Gulf Coast regions in 2005, insurance costs related to oil and gas assets in these regions have increased significantly. We may be unable to obtain insurance on our interest in Starfish at rates we consider reasonable.

We own a 50% non-operating membership interest in Starfish, whose assets are located in the Gulf of Mexico and southwestern Louisiana. During 2005, Hurricanes Katrina and Rita caused severe and widespread damage to oil and gas assets in the Gulf of Mexico and Gulf Coast regions. The loss to both offshore and onshore assets resulting from the hurricanes has led to substantial insurance claims within the oil and gas industry. Insurance costs have increased within this region as a result of these developments. We have renewed our insurance coverage relating to Starfish and mitigated a portion of the cost increase by reducing our coverage and broadening the self-insurance element of our overall coverage. In the future, we may be unable to obtain adequate insurance on our interest in Starfish at rates we consider reasonable and as a result may experience losses that are not insured or that exceed the maximum limits under our insurance policies. If a significant negative event that is not fully insured occurs with respect to Starfish, it could adversely affect 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, business 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. Further, our ability to successfully integrate acquired companies depends in part on its 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.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments will subject our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

Risks Related to Our Partnership Structure

We may issue additional common units without unitholder approval, which would dilute your 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. Unitholders did not elect our General Partner, but will now have the right to elect our General Partner's board of directors. The 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 General Partner 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 its board of directors.

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 the Partnership Agreement was considered participation in the "control" of our business. After the redemption and merger, unitholders will elect the members of the General Partner 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.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders. For example, the state of Texas and the state of Michigan have both instituted income-based taxes that result in an entity level tax for the partnership. Beginning in 2008, the Partnership will be required to pay Texas franchise tax at a maximum effective rate of 1.0% of our gross income apportioned to Texas in the prior year. Additionally, the Michigan Business Tax, which contains two prongs, also imposes a tax on the partnership. The two prongs comprise a tax at the rate of 0.8% of a taxpayer's modified gross receipts and a tax at the rate of 4.95% of the taxpayer's business income. Each of the above mentioned rates also includes a surcharge of 21.99% resulting in overall rates of 0.97% and 6.03%. The imposition of entity level taxes on us by Texas and Michigan and, if applicable, by any other state will reduce the cash available for distribution to our unitholders. The 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 additional amounts of entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

Tax Risks to Existing Unitholders

An existing unitholder may be required to recognize gain as a result of the decrease in his distributive share of our nonrecourse liabilities as a result of the Merger.

As result of the merger, the allocable shares of nonrecourse liabilities allocated to existing unitholders will be recalculated to take into account common units issued by us in exchange for Company common stock. If an existing unitholder experiences a reduction in our unitholder's share of nonrecourse liabilities as a result of the merger, a "reducing debt shift," our unitholder will be deemed to have received a cash distribution equal to the amount of the reduction. A reduction in our unitholder's share of liabilities will result in a corresponding basis reduction in our unitholder's common units. A reducing debt shift and the resulting deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by our unitholder. If the reduction in our unitholder's share of nonrecourse liabilities and the resulting deemed cash distribution exceeds such unitholder's common unit basis, such unitholder would recognize gain in an amount equal to such excess. We do not expect that any constructive cash distribution will exceed an existing unitholder's tax basis in our common units.

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 IRS were to treat us as a corporation for federal income tax purposes, then our cash available for distribution to unitholders could 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. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

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 flows 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.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

The 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 will be reduced to reflect the impact of that law on us.

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 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 common units, he 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 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 tax basis in those common units, even if the price the unitholder receives is less than his 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 the unitholder sells his 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 and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file 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.

Because we cannot match transferors and transferees of our common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from 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. If the IRS were to challenge this 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 loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he 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 a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, he 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 to the short seller, 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 loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the General Partner and our 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 will 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 unitholders and the General Partner. 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 and the General Partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code 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 the General Partner and certain of 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 12-month period would result in our termination for federal income tax purposes.

We would be considered to have terminated for federal income tax purposes if there were a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and the unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we would make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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 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 facility, natural gas pipelines, NGL pipelines, and crude oil pipeline as of and for the year ended December 31, 2007.

Gas Processing Facilities:

Facility	Location	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2007 Natural Gas Throughput	Utilization of Design Capacity	NGL Throughput
			(Mcf/d)	(Mcf/d)		(Gal/d)
East Texas:						
East Texas processing plant	Panola County, TX	2005	200,000	175,400	88%	NA
Oklahoma:						
Arapaho processing plant	Custer County, OK	2000	100,000	104,000	104%	239,800
Appalachia:						
Kenova processing plant(1)	Wayne County, WV	1996	160,000	133,200	83%	NA
Boldman processing plant(1)	Pike County, KY	1991	70,000	39,300	56%	NA
Cobb processing plant	Kanawha County, WV	2005	30,000	27,700	92%	NA
Kermit processing plant(1)(2)	Mingo County, WV	2001	32,000	NA	NA	NA
Michigan:						
Fisk processing plant	Manistee County, MI	1998	35,000	5,200	15%	10,700
Gulf Coast:						
Javelina processing plant	Corpus Christi, TX	1989	142,000	114,500	81%	1,048,800

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

(2) 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.

Fractionation Facility:

Pipeline	Location	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2007 NGL Throughput	Year ended December 31, 2007 Utilization of Design Capacity
			(Gal/d)	(Gal/d)	
Appalachia:					
Siloam fractionation plant	South Shore, KY	1957	600,000	452,200	75%

Natural Gas Pipelines:

Facility	Location	Miles	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2007 Natural Gas Throughput	Year ended December 31, 2007 Utilization of Design Capacity
				(Mcf/d)	(Mcf/d)	
East Texas:						
East Texas gathering system	Panola County, TX	311	1990	440,000	413,700	94%
Oklahoma:						
Foss Lake gathering system	Roger Mills and Custer County, OK	240	1998	120,000	104,000	87%
Grimes gathering system	Beckham, Roger Mills Counties, OK	25	2005	25,000	12,500	50%
Woodford gathering system	Hughes, Pittsburg and Coal Counties, OK	40	2006	300,000	114,000	38%
Other Southwest:						
Appleby gathering system	Nacogdoches County, TX	139	1990	85,000	58,700	69%
Other gathering systems	Various		Various	36,500	8,700	24%
Michigan:						
90-mile gas gathering pipeline	Manistee, Mason and Oceana Counties, MI	90	1994-1998	35,000	5,200	15%

NGL Pipelines:

Pipeline	Location	Miles	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2007 NGL Throughput	Year ended December 31, 2007 Utilization of Design Capacity
				(Gal/d)	(Gal/d)	
Appalachia:						
Ranger to Kenova(3)	Lincoln County, WV to Wayne County, WV	40	1976	831,000	0	0%
Kenova to Siloam	Wayne County, WV to South Shore, KY	40	1957	831,000	253,500	31%
East Texas:						
East Texas liquidline	Panola County, TX	37.5	2005	630,000	492,100	78%

(3) NGLs transported through the Ranger to Kenova pipeline are combined with NGLs recovered at the Kenova facility and the combined NGL stream is transported in the Kenova to Siloam pipeline.

Crude Oil Pipeline:

Pipeline	Location	Miles	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2007 NGL Throughput	Utilization of Design Capacity
				(Gal/d)	(Gal/d)	
Michigan:						
Michigan crude pipeline....................	Manistee County, MI to Crawford County, MI	250	1973	60,000	14,000	23%

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. In some cases, property on which our pipelines were built was purchased in fee or held under long-term leases. Our Siloam fractionation plant and Kenova processing plant are on land that we own in fee.

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 to secure the debt of our subsidiary, MarkWest Energy Operating Company, L.L.C. (the "Operating Company"), as discussed in Note 11 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

ITEM 3. Legal Proceedings

We are subject to a variety of risks and disputes, and are a party to various legal proceedings in the normal course of our business. We maintain insurance policies in amounts and with coverage and deductibles as we believe are reasonable and prudent. However, we cannot assure either 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 the Partnership and the Company (collectively MarkWest); 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 provision and accruals for potential losses associated with all legal actions have been made in the financial statements.

In June 2006, the Office of Pipeline Safety ("OPS") issued a Notice of Probable Violation and Proposed Civil Penalty ("NOPV") (CPF No. 2-2006-5001) to both MarkWest Hydrocarbon and Equitable Production Company. The NOPV is associated with the pipeline leak and an ensuing explosion and fire that occurred on November 8, 2004 in Ivel, Kentucky on an NGL pipeline owned by Equitable Production Company and previously leased and operated by our subsidiary, MarkWest Energy Appalachia, LLC. The NOPV sets forth six counts of violations of applicable regulations, and a proposed civil penalty in the aggregate amount of $1,070,000. An administrative hearing on the matter, previously set for the last week of March, 2007, was postponed to allow the administrative record to be produced and to allow OPS an opportunity to respond to a motion to dismiss one of the counts of violations, which involves $825,000 of the $1,070,000 proposed penalty. This count arises out of alleged activity in 1982 and 1987, which predates MarkWest's leasing and operation of the pipeline. MarkWest believes it has viable defenses to the remaining counts and will vigorously defend all applicable assertions of violations at the hearing.

Related to the above referenced 2004 pipeline explosion and fire incident, MarkWest Hydrocarbon and the Partnership have filed an action captioned *MarkWest Hydrocarbon, Inc., et al. v. Liberty Mutual Ins. Co., et al.* (District Court, Arapahoe County, Colorado, Case No. 05CV3953 filed August 12, 2005), as removed to the U.S. District Court for the District of Colorado, (Civil Action No. 1:05-CV-1948, on October 7, 2005) against their All-Risks Property and Business Interruption insurance carriers as a result of the insurance companies' refusal to honor their insurance coverage obligation to pay the Partnership for certain costs related to the pipeline incident. The costs include internal costs incurred for damage to, and loss of use of the pipeline, equipment and products; extra transportation costs incurred for transporting the liquids while the pipeline was out of service; reduced volumes of liquids that could be processed; and the costs of complying with the OPS Corrective Action Order (hydrostatic testing, repair/replacement and other pipeline integrity assurance measures). Following initial discovery, MarkWest was granted leave of the Court to amend its complaint to add a bad faith claim and a claim for punitive damages. The Partnership has not provided for a receivable for any of the claims in this action because of the uncertainty as to whether and how much it will ultimately recover under the policies. The costs associated with this claim have been expensed as incurred and any potential recovery from the All-Risks Property and Business Interruption insurance carriers will be treated as "other income" if and when it is received. The Defendant insurance companies and MarkWest have each filed separate summary judgment motions in the action.

With regard to our Javelina facility, MarkWest Javelina is a party with numerous other defendants to several lawsuits brought by various plaintiffs who had residences or businesses located near the Corpus Christi industrial area, an area which included the Javelina gas processing plant, and several petroleum, petrochemical and metal processing and refining operations. These suits, *Victor Huff v. ASARCO Incorporated, et al.* (Cause No. 98-01057-F, 214th Judicial Dist. Ct., County of Nueces, Texas, original petition filed in March 3, 1998); *Jason and Dianne Gutierrez, individually and as representative of the estate of Sarina Galan Gutierrez* (Cause No. 05-2470-A, 28th Judicial District, severed May 18, 2005, from the *Gonzales* case cited above); and *Esmerejilda G. Valasquez, et al. v. Occidental Chemical Corp., et al.,* Case No. A-060352-C, 128th Judicial District, Orange County, Texas, original petition filed July 10, 2006; as refiled from previously dismissed petition captioned *Jesus Villarreal v. Koch Refining Co. et al.*, Cause No. 05-01977-F, 214th Judicial Dist. Ct., County of Nueces, Texas, originally filed April 27, 2005), set forth claims for wrongful death, personal injury or property damage, harm to business operations and nuisance type claims, allegedly incurred as a result of operations and emissions from the various industrial operations in the area or from products Defendants allegedly manufactured, processed, used, or distributed. The actions have been and are being vigorously defended and; based on initial evaluation and consultations; it appears at this time that these actions should not have a material adverse impact on our business.

In the ordinary course of business, we are party to various other legal actions. In the opinion of management, none of these actions, either individually or in the aggregate, will have a material adverse effect on our financial condition, liquidity or results of operations.

ITEM 4. Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of the holders of our common units during the fourth quarter of the fiscal year ended December 31, 2007.

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 ("AMEX"), 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.

On January 25, 2007, the board of directors of the general partner of the Partnership declared a two-for-one unit split, which became effective February 28, 2007. For all periods presented, all references to the number of units and per unit net income and distribution amounts included in this report have been adjusted to give the effect for the unit split.

The following table sets forth the high and low sales prices of the common units as reported by NYSE or AMEX, as well as the amount of cash distributions paid per quarter for 2007 and 2006:

Quarter Ended	High	Low	Per Common Unit	Per Subordinated Unit(1)	Record Date	Payment Date
December 31, 2007	$34.71	$29.55	$0.570	$—	February 7, 2008	February 14, 2008
September 30, 2007	$37.25	$29.78	$0.550	$—	November 8, 2007	November 14, 2007
June 30, 2007	$38.00	$33.27	$0.530	$0.530	August 8, 2007	August 14, 2007
March 31, 2007	$36.45	$28.51	$0.510	$0.510	May 9, 2007	May 15, 2007
December 31, 2006	$29.95	$23.38	$0.500	$0.500	February 8, 2007	February 14, 2007
September 30, 2006	$24.75	$20.50	$0.485	$0.485	November 3, 2006	November 14, 2006
June 30, 2006	$23.33	$19.75	$0.460	$0.460	August 7, 2006	August 14, 2006
March 31, 2006	$24.00	$21.76	$0.435	$0.435	May 5, 2006	May 15, 2006

(1) On August 15, 2007, the Partnership converted its remaining 1.2 million subordinated units to common units.

As of February 15, 2008 there were 167 holders of record of our common units.

Distributions of Available Cash

Within 45 days after the end of each quarter, we will distribute all of our "Available Cash" to unitholders of record on the applicable record date. We will make distributions of "Available Cash" to all unitholders (common and Class A), pro rata and we will make distributions of Hydrocarbon Available Cash (as defined in our amended and restated partnership agreement) pro rata 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 (excluding cash at the Company);
- 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 revolving credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Generally, Hydrocarbon Available Cash is defined as all cash and cash equivalents on hand derived from or attributable to our ownership of, or sale or other disposition of, the shares of common stock of the Company.

Our ability to distribute available cash is contractually restricted by the terms of our credit facilities. Our credit facilities 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 facilities. In addition, our credit facilities prohibit us from borrowing more than $0.375 per outstanding unit during any consecutive 12-month period for the purpose of making distributions to unitholders. Our credit facilities provide that any amount so borrowed must be repaid once annually.

There is no guarantee that we will pay a minimum quarterly distribution on the common units in any quarter.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash after a minimum quarterly distribution and certain target distribution levels have been achieved. All incentive distribution rights were eliminated as a result of the merger.

Distributions of Cash Upon Liquidation

If we dissolve in accordance with the 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 its creditors. We will distribute any remaining proceeds to the unitholders, 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, 2007, regarding our common units that may be issued upon conversion of outstanding restricted units granted under our 2003 Long-Term Incentive Plan to employees and directors of our general partner and employees of its affiliates who perform services for us. For more information about this plan, which did not require approval by the Partnership's limited partners, you should read Note 13 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

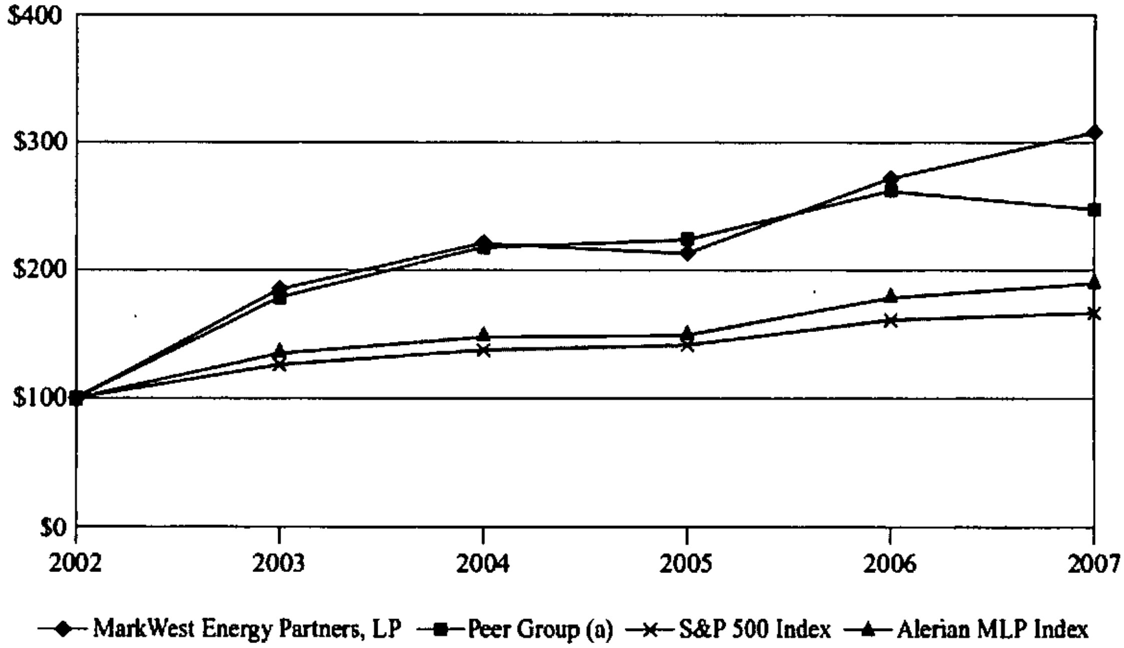
	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights(1)	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders:	—	—	—
Equity compensation plans not approved by security holders:			
Long-Term Incentive Plan—(restricted units)	125,250	—	87,280
Long-Term Incentive Plan—(unit options)	—	—	600,000
	125,250	—	687,280

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

In connection with the Merger, the Partnership assumed the MarkWest Hydrocarbon, Inc. 2006 Stock Incentive Plan ("2006 Plan") which converted the outstanding shares of restricted stock granted under the 2006 Plan to restricted units. The converted restricted units will remain outstanding under the term of the 2006 Plan until their respective settlement dates. The 2008 Long-Term Incentive Plan ("2008 LTIP") was approved by the unitholders on February 21, 2008, which makes available 2.5 million Partnership common units for issuance in the future. Refer to Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

PERFORMANCE GRAPH

Total Return to Stockholders
(Assumes $100 Investment on 12/31/02)



(a) Comprised of Crosstex Energy L.P., Atlas Pipeline Partners L.P., Martin Midstream Partners L.P., Magellan Midstream Partners, L.P.

ITEM 6. Selected Financial Data

The following table sets forth selected consolidated historical financial and operating data for MarkWest Energy Partners. We have derived the summary selected historical financial data from our consolidated financial statements and related notes. All earnings per share and dividend information have been updated to reflect the February 2007 two-for-one unit split. The selected financial data should be read in conjunction with the combined and 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,				
	2007	2006	2005(1)	2004(2)	2003(3)
	(in thousands, except per share amounts)				
Statement of Operations:					
Revenues(4):	$602,879	$629,911	$541,090	$319,119	$117,430
Operating expenses:					
Purchased product costs	358,720	376,237	408,884	229,339	70,832
Facility expenses(4)	75,036	60,112	47,972	29,911	20,463
Selling, general and administrative expenses	51,334	44,377	21,597	16,162	8,598
Depreciation	40,171	29,993	19,534	15,556	7,548
Amortization of intangible assets	16,672	16,047	9,656	3,640	—
Loss (gain) on disposal of property, plant and equipment	7,564	(192)	(24)	(29)	—
Accretion of asset retirement obligations	114	102	159	13	—
Impairments	356	—	—	130	1,148
Total operating expenses	549,967	526,676	507,778	294,722	108,589
Income from operations	52,912	103,235	33,312	24,397	8,841
Earnings (losses) from unconsolidated affiliates	5,309	5,316	(2,153)	(65)	—
Interest income	2,887	962	367	87	14
Interest expense	(38,946)	(40,666)	(22,469)	(9,236)	(3,087)
Amortization of deferred financing costs and original issue discount (a component of interest expense)	(2,717)	(9,094)	(6,780)	(5,236)	(984)
Miscellaneous (expense) income	(1,002)	11,100	78	15	(25)
Income before income taxes	18,443	70,853	2,355	9,962	4,759
Income tax expense	(1,244)	(769)	—	—	—
Net income	$17,199	$70,084	$2,355	$9,962	$4,759
Net income per limited partner unit: (see Item 8—Note 2)					
Basic	$0.12	$2.45	$0.01	$0.66	$0.47
Diluted	$0.12	$2.44	$0.01	$0.65	$0.47
Cash distributions declared per limited partner unit	$2.09	$1.79	$1.60	$1.43	$1.16
Balance Sheet Data (at December 31):					
Working capital	$(19,734)	$4,258	$11,944	$10,547	$2,457
Property, plant and equipment, net	823,737	550,886	492,961	280,635	184,214
Total assets	1,392,834	1,114,780	1,046,093	529,422	212,871
Total long-term debt	552,695	526,865	601,262	225,000	126,200
Partners' capital	611,323	452,649	307,175	241,142	64,944
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$149,399	$150,977	$42,090	$42,275	$21,229
Investing activities	(312,085)	(119,338)	(469,308)	(273,176)	(112,893)
Financing activities	154,789	(17,342)	423,060	246,411	97,641
Other Financial Data:					
Maintenance capital expenditures(5)	$3,602	$2,291	$2,181	$1,163	$1,041
Growth capital expenditures(5)	308,708	75,096	68,569	29,304	1,903
Total capital expenditures	$312,310	$77,387	$70,750	$30,467	$2,944

(1) We completed our investment in Starfish on March 31, 2005, and acquired Javelina (Gulf Coast) on November 1, 2005.

(2) We acquired our Hobbs lateral pipeline in April 2004.
We acquired our East Texas System in late July 2004.

(3) We acquired our Foss Lake gathering system in December 2003.
We acquired our Arapaho processing plant in December 2003.

We acquired our Pinnacle gathering systems in late March 2003.
We acquired our Lubbock pipeline (a/k/a the Power-tex Lateral Pipeline) in September 2003.
We acquired our Michigan Crude Pipeline in December 2003.

(4) Revenues and facility expenses have been impacted by the Partnership's commodity derivative instruments. As discussed further in Item 7A. Quantitative and Qualitative Disclosures about Market Risk contained in this Form 10-K, volatility in any given period related to unrealized gains and losses on our derivative positions can be significant. We ultimately expect those gains and losses to be offset when they become realized. The following table summarizes the unrealized and realized (losses) and gains included in revenues and facility expenses for the year ended December 31 (in thousands):

	2007	2006	2005	2004	2003
Revenues:					
Unrealized (loss) gain	$(62,388)	$6,245	$(657)	$(71)	$(67)
Realized loss	(4,155)	(613)	(1,194)	(749)	(713)
	(66,543)	5,632	(1,851)	(820)	(780)
Facility expenses:					
Unrealized gain	12	—	—	—	—
Total (loss) gain	$(66,531)	$5,632	$(1,851)	$(820)	$(780)

(5) Maintenance capital includes expenditures to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Growth capital includes expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Growth capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition.

Operating Data

	Year Ended December 31,				
	2007	2006	2005	2004	2003
Southwest:					
East Texas(1)					
Gathering systems throughput (Mcf/d)	413,700	378,100	321,000	259,300	NA
NGL product sales (gallons)	179,601,000	161,437,000	126,476,000	41,478,000	NA
Oklahoma					
Foss Lake gathering systems throughput (Mcf/d)	104,000	87,500	75,800	60,900	57,000
Woodford gathering systems throughput (Mcf/d)(2)	114,000	34,000	NA	NA	NA
Grimes gathering system throughput (Mcf/d)	12,500	NA	NA	NA	NA
Arapaho NGL product sales (gallons)	87,522,000	79,093,000	60,903,000	45,273,000	2,910,000
Other Southwest					
Appleby gathering systems throughput (Mcf/d)	58,700	34,200	33,400	27,100	23,800
Other gathering systems throughput (Mcf/d)	8,700	18,300	16,500	17,000	20,500
Northeast:					
Appalachia(3)					
Natural gas processed for a fee (Mcf/d)	200,200	203,000	197,000	203,000	202,000
NGLs fractionated for a fee (Gal/day)	452,200	454,800	430,000	475,000	458,000
NGL product sales (gallons)	43,815,100	43,271,000	41,700,000	42,105,000	40,305,000
Michigan:					
Natural gas processed for a fee (Mcf/d)	5,200	6,500	6,600	12,300	15,000
NGL product sales (gallons)	3,898,600	5,643,000	5,697,000	9,818,000	11,800,000
Crude oil transported for a fee (Bbl/d)	14,000	14,500	14,200	14,700	15,100
Gulf Coast(4):					
Natural gas processed for a fee (Mcf/d)	114,500	124,300	115,000	NA	NA
NGLs fractionated for a fee (Bbl/day)	25,000	26,200	19,400	NA	NA

(1) We acquired the East Texas system in late July 2004.

(2) In late 2006 we began the construction and operation of the Woodford gathering system and compression system in a four-county region in the Arkoma Basin in eastern Oklahoma. On December 1, 2006, the Partnership began gathering gas on that system. The 2006 volume reported is the average daily rate for the month of December.

(3) Includes throughput from the Kenova, Cobb, and Boldman processing plants.

(4) We acquired the Javelina system (Gulf Coast) on November 1, 2005.

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 Consolidated Financial Data" and our consolidated financial statements and accompanying notes included elsewhere in this report. These statements are based on current expectations and assumptions that are subject to risks and uncertainties. Actual results could differ materially from those expressed or implied in the forward-looking statements as a result of a number of factors.

Overview

We are a master limited partnership whose diverse portfolio of midstream assets serves many of the most prolific natural gas basins in the United States. The Partnership is primarily engaged in the gathering, processing and transmission of natural gas; the transportation, fractionation and storage of natural gas liquids; and the gathering and transportation of crude oil.

Our primary business strategy is to grow sustainable cash flow and cash distributions to our unitholders. The key elements of our strategy are to optimize existing assets and services, to expand operations through new construction, and to target accretive and complementary acquisitions and expansion opportunities that provide attractive growth potential.

On February 21, 2008, we completed a merger by and among MarkWest Hydrocarbon, Inc. and MWEP, L.L.C., whereby MarkWest Hydrocarbon, Inc. became a wholly owned subsidiary of the Partnership. We anticipate that, through the elimination of the incentive distribution rights, we will reduce our cost of capital and strengthen our competitive position. The financial statements presented include the consolidated results of operations for the Partnership for periods prior to the merger.

We are required by our partnership agreement to distribute available cash from operating surplus each quarter to pay the minimum quarterly distribution. The amount of cash we can distribute on our units depends principally on the amount of cash generated from our operations.

Our distributions have increased from $0.25 per unit for the quarter ended September 30, 2002 (its first full quarter of operation after its initial public offering), to $0.57 per unit for the quarter ended December 31, 2007. We issued 4.8 million common units at our initial public offering in 2002, compared to 39.4 million common units outstanding on December 31, 2007.

A significant part of our business strategy includes acquiring additional businesses that will allow us to increase distributions to our unitholders. We regularly consider and enter into discussions regarding potential acquisitions. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations.

In September 2006, we announced a strategic agreement with Newfield Exploration which involves the construction and operation of a new gathering and compression system to support all Newfield operated wells in a 200-square-mile project area situated in a four-county region in the Arkoma Basin in eastern Oklahoma. We have continued to expand our opportunities in this area.

In October 2007, we announced we would invest approximately $100 million to expand our Javelina plant, located in Corpus Christi, Texas. The steam methane reformer facility is expected to commence delivering high-purity hydrogen in early 2010. This new facility is expected to produce in excess of 50 million cubic feet per day of high-purity hydrogen.

In January 2008, we entered into an option agreement with Midcontinent Express Pipeline LLC ("MEP LLC") that provides us with a one-time right to acquire 10 percent of the equity of MEP LLC after construction is complete on the Midcontinent Express Pipeline ("MEP") and it is placed into service. MEP LLC is a 50/50 joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. The MEP, connecting Bennington, Oklahoma, and Perryville, Louisiana, will have initial capacity of 1.4 Bcf/d.

Impact of Acquisitions on Comparability of Financial Results

In reviewing our historical results of operations, investors should be aware of the impact of our past acquisitions, which fundamentally affect the comparability of our results of operations over the periods discussed.

Since our initial public offering, we have completed nine acquisitions for an aggregate purchase price of $810 million, net of working capital. Six of these acquisitions occurred in 2003 and 2004 and their results are included in the results of operations from the acquisition date.

Two acquisitions occurred in 2005 and are included in the results of operations from the acquisition date.

- The Starfish acquisition closed on March 31, 2005, for consideration of $41.7 million. Nine months of Starfish activity is reflected in results of operations for the year ended December 31, 2005.
- The Javelina acquisition closed on November 1, 2005, for consideration of $357.0 million, plus $41.8 million for net working capital. As a result, only two months of activity for Javelina is reflected in the results of operations for the year ended December 31, 2005.

One acquisition occurred 2006 and it is included in the results of operations from the acquisition date.

- The Santa Fe acquisition closed on December 29, 2006 for consideration of $15.0 million. As a result, activity for Grimes gathering system is reflected in the results of operations beginning in 2007.

Our Relationship with MarkWest Hydrocarbon, Inc.

We were formed by MarkWest Hydrocarbon in 2002 to acquire most of its natural gas gathering and processing assets and NGL transportation, fractionation and storage assets. MarkWest Hydrocarbon remains one of our largest customers. We expect to continue deriving a portion of our revenues from the services we provide under our contracts with MarkWest Hydrocarbon for the foreseeable future; however, the percentage of our revenues and net operating margins (a non-GAAP financial measure, see Item 1. Business—*Our Contracts*) will likely continue to decline as our other businesses grow. For the year ended December 31, 2007, 2006 and 2005, revenues from MarkWest Hydrocarbon accounted for 12% of our consolidated revenues.

MarkWest Hydrocarbon was founded in 1988 as a partnership and later incorporated in Delaware. MarkWest Hydrocarbon is an energy company primarily focused on marketing NGLs. MarkWest Hydrocarbon's assets consist primarily of partnership interests in the Partnership and certain processing agreements in Appalachia.

Neither we nor our General Partner have any employees. However, under a Services Agreement entered into between our General Partner and MarkWest Hydrocarbon, Inc., MarkWest Hydrocarbon acts in a management capacity rendering day-to-day operational, business and asset management, accounting, information services, personnel and related administrative services to the Partnership. In return, the Partnership reimburses MarkWest Hydrocarbon for all documented expenses incurred on behalf of the Partnership and which are expressly designated as reasonably necessary for the performance of the prescribed duties and specified functions. General corporate expenses and costs that are not specifically linked to either MarkWest Hydrocarbon or us are allocated in accordance with an approved allocation methodology which is designed to ensure that neither entity bears a disproportionate or unfair burden of the other company's costs and expenses, and is reflective of respective statements of operations.

As a result of the merger and redemption discussed further in Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K, we will continue to have a relationship with the Company. As of February 22, 2008, the Company and its subsidiaries, in the aggregate, owns a 31% interest in the Partnership, consisting of 22,500,000 Class A Units. The merger and redemption do not affect the Services Agreement or any other operating contractual arrangement.

Results of Operations

We reported net income of $17.2 million for the year ended December 31, 2007 compared to net income of $70.0 million for the year ended December 31, 2006. Contributing factors to the $52.9 million change in net income were:

- losses from derivative instruments increasing $72.1 million. This change resulted from a $62.4 million increase in non-cash unrealized losses, which are recognized in revenue and facility expense and $3.5 million increase in cash realized losses, which are recognized in revenue and facilities expense. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for further information on the potential volatility to our unrealized gains and losses.

- a $12.1 million decrease in miscellaneous (expense) income mainly due to the change in insurance recoveries, net of premiums, from our equity investment in Starfish.

- a $7.8 million loss primarily from the conveyance of certain property, plant and equipment, and write off of leasehold improvements in connection with our settlement with Equitable.

- a $7.0 million increase in selling, general and administrative expenses mainly related to merger expenses.

- a $36.8 million increase in operating income before items not allocated to segments due to the Woodford gathering system expansion, the acquisition of the Grimes gathering system, increased volumes and pricing in Other Southwest and East Texas, improved pricing offset by declines in almost all products in Javelina, and the receipt of a utility refund of $3.6 million in Javelina from a rate case concluded in the first quarter of 2007.

- a $6.4 million decrease in amortization of deferred finance costs attributable to costs associated with our debt refinancing in the third quarter of 2006.

Segment Reporting

Our six geographical segments are: East Texas, Oklahoma, Other Southwest, Gulf Coast, Appalachia and Michigan. We capture information in this MD&A by geographical segment, except that certain items are not allocated to our business segments because management does not consider them in its evaluation of business unit performance. The segment information appearing in Note 19 to the consolidated financial statements, *Segment Information*, in Item 8 of this Form 10-K, is presented on a basis consistent with the Partnership's internal management reporting, in accordance with SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.*

Year Ended December 31, 2007, Compared to Year Ended December 31, 2006

East Texas

	Year ended December 31,	
	2007	2006
	(in thousands)	
Revenue	$206,250	$174,279
Operating expenses:		
Purchased product costs	113,693	91,637
Facility expenses	16,871	15,683
Depreciation	9,607	7,783
Amortization of intangible assets	8,269	8,244
Accretion of asset retirement obligations	52	44
Total operating expenses before selling, general and administrative expenses	148,492	123,391
Operating income before items not allocated to segments	$57,758	$50,888

Revenue. Revenue increased $32.0 million, or 18%, during the year ended December 31, 2007, relative to 2006. Revenues increased as a result of 18.2 million additional NGL gallons sold and 35,600 Mcf/d increase in gathering system throughput. In addition, the average price for all NGLs sold has increased in 2007 as compared to the average price in 2006. This increase was partially offset by a decrease in sales of natural gas due to an October 2006 change from a keep whole purchase to a processing contract at our Carthage facility.

Purchased Product Costs. Purchased product costs increased $22.1 million, or 24%, during the year ended December 31, 2007, relative to 2006. The increase is related to increased average NGL pricing and additional NGL volumes purchased under percent of liquid contracts offset by the contract change discussed above.

Facility Expenses. Facility expenses increased $1.2 million, or 8%, during the year ended December 31, 2007, relative to 2006. The increase is related to increased payroll costs due to expanded operations, increase leased compression expense until rented compressors were replaced with purchased compressors and increased property tax rates.

Depreciation. Depreciation expenses increased $1.8 million, or 23%, during the year ended December 31, 2007, relative to 2006. The change is primarily due to expansion projects during 2007 and a full year of depreciation on 2006 projects.

Oklahoma

	Year ended December 31,	
	2007	2006
	(in thousands)	
Revenue	$229,800	$207,510
Operating expenses:		
Purchased product costs	153,241	170,168
Facility expenses	20,291	7,883
Depreciation	11,104	3,007
Amortization of intangible assets	598	—
Accretion of asset retirement obligations	28	26
Total operating expenses before selling, general and administrative expenses	185,262	181,084
Operating income before items not allocated to segments	$44,538	$26,426

Revenue. Revenue increased $22.3 million, or 11%, during the year ended December 31, 2007, relative to 2006. This increase is related primarily to an increase in volumes from our Woodford gathering system and the acquisition of the Grimes gathering system. The Woodford gathering system, which we continue to develop and expand, had only one month of activity in the 2006 year. In addition, increased NGL and condensate revenue from our other gathering systems occurred due to increased volumes and pricing but was largely offset by decreased revenue attributable to some changes from purchasing contracts to gathering contracts.

Purchased Product Costs. Purchased product costs decreased $16.9 million, or 10%, during the year ended December 31, 2007, relative to 2006. The decrease was mainly attributable to the contractual changes described above and was offset by gas purchases related to our Woodford gathering system, which began operation in December 2006.

Facility Expenses. Facility expenses increased $12.4 million, or 157%, during the year ended December 31, 2007, relative to 2006. The increase was primarily due to the startup of operations for the Woodford gathering system and acquisition of the Grimes gathering system described above.

Depreciation. Depreciation expenses increased $8.0 million, or 268%, during the year ended December 31, 2007, relative to 2006. The change is due to the Woodford gathering system being operational for a full year in 2007.

Other Southwest

	Year ended December 31,	
	2007	2006
	(in thousands)	
Revenue	$67,411	$84,595
Operating expenses:		
Purchased product costs	43,954	67,349
Facility expenses	6,883	5,638
Depreciation	4,493	4,100
Accretion of asset retirement obligations	21	20
Impairment	356	—
Total operating expenses before selling, general and administrative expenses	55,707	77,107
Operating income before items not allocated to segments	$11,704	$7,488

Revenue. Revenue decreased $17.2 million, or 20%, during the year ended December 31, 2007, relative to 2006. The decrease is principally attributed to a late second quarter 2006 change in the contract mix at our Appleby facility, from purchasing contracts to gathering contracts. This decrease was partially offset by transportation volumes increasing by approximately 24,500 Mcf/d.

Purchased Product Costs. Purchased product costs decreased $23.4 million, or 35%, during the year ended December 31, 2007, relative to 2006. The decrease in costs is primarily a result of lower purchased volumes due to a change in our contract mix.

Facility Expenses. Facility expenses increased $1.2 million, or 22%, during the year ended December 31, 2007, relative to 2006. The increase was due to higher compression and system operating costs at our Appleby facility.

Depreciation. Depreciation expense increased $0.4 million, or 10%, during the year ended December 31, 2007, relative to 2006. The change is primarily due to the addition of the redesign and expansion of the compressor stations in our Appleby facility.

Impairments. Impairments increased $0.4 million during the year ended December 31, 2007, relative to 2006. The increase was due to the deemed impairment of a system as further discussed in Note 10 to the consolidated financial statements included in Item 8 of this Form 10-K.

Appalachia

	Year ended December 31,	
	2007	2006
	(in thousands)	
Revenues:		
Unaffiliated	$1,924	$2,027
Affiliated	74,981	73,636
Total revenue	76,905	75,663
Operating expenses:		
Purchased product costs	44,718	43,648
Facility expenses	14,463	13,997
Depreciation	3,410	3,573
Accretion of asset retirement obligations	13	12
Total operating expenses before selling, general and administrative expenses	62,604	61,230
Operating income before items not allocated to segments	$14,301	$14,433

Revenue. Total revenue increased $1.2 million, or 2%, during the year ended December 31, 2007, relative to 2006. Effective November 16, 2007, Appalachia conveyed its Maytown facility to Equitable. As a result, revenue recognized in Appalachia from that point forward was recognized net as an agent whereas before, Appalachia recognized revenue gross as a principal. This resulted in decreased revenues of approximately $8.2 million during 2007. Without this change, revenue would have increased $9.5 million, or 13%, during the year ended December 31, 2007 relative to 2006. The increase was related to a 0.5 million gallons increase in volumes and a $0.19 per gallon price increase at our Maytown facility.

Purchased Product Costs. Purchased product costs increased $1.1 million, or 2%, during the year ended December 31, 2007, relative to 2006. As discussed above, purchased product costs were decreased by $8.2 million during 2007 as a result of the conveyance of its Maytown facility to Equitable. Without this change, purchased product costs would have increased by $9.3 million, or 21%, during the year ended December 31, 2007 relative to 2006. The rise in costs is primarily a result of volumes and prices increasing at the Maytown facility, which accounted for $7.4 million of the overall increase. Trucking expenses associated with the shutdown of the Appalachia Liquids Pipeline System ("ALPS") increased purchased product costs by $1.6 million.

Michigan

	Year ended December 31, 2007	Year ended December 31, 2006
	(in thousands)	
Revenue	$11,942	$13,282
Operating expenses:		
Purchased product costs	3,114	3,435
Facility expenses	6,069	5,721
Depreciation	4,668	5,015
Total operating expenses before selling, general and administrative expenses	13,851	14,171
Operating loss before items not allocated to segments	$(1,909)	$(889)

Revenue. Revenue decreased $1.3 million, or 10%, during the year ended December 31, 2007, relative to 2006. The change is primarily due to decreased volumes, offset by an increase in prices at our West Shore facility. In addition, a sale of inventory in our Michigan crude pipeline did not recur in 2007.

Purchased Product Costs. Purchased product costs decreased $0.3 million, or 9%, during the year ended December 31, 2007, relative to 2006. The decrease in costs is due to lower volumes offset by higher prices at our West Shore facility, as described above. In addition, a sale of inventory in our Michigan crude pipeline did not recur in 2007.

Given the continuing losses and moderately positive cash flows relating to the western Michigan gathering assets, management continues to consider alternatives, and we are evaluating potential impairments on these assets. Management determined there were no impairments as of December 31, 2007.

Gulf Coast

	Year ended December 31, 2007	Year ended December 31, 2006
	(in thousands)	
Revenue	$77,114	$68,950
Operating expenses:		
Facility expenses	10,471	11,190
Depreciation	6,619	6,500
Amortization of intangible assets	7,805	7,803
Total operating expenses before selling, general and administrative expenses	24,895	25,493
Operating income before items not allocated to segments	$52,219	$43,457

Revenue. Revenues in the Gulf Coast business unit are generated under percent-of-proceeds arrangements and are generally reported net of purchased product costs (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—*Revenue Recognition in Critical Accounting Policies and Estimates*). We gather and process refinery off-gas on behalf of refiners, return or sell the resulting residue gas, condensate and NGLs at market prices and remit to refiners an agreed-upon percentage of the proceeds based on an actual revenues.

Revenue increased $8.2 million, or 12%, during the year ended December 31, 2007, relative to 2006. This was primarily attributable to the incremental sale of 0.3 million barrels of pentanes, which increased revenue by approximately $3.0 million. The pentanes are stored as a result of their seasonality and timing of the revenue generated from the sale cannot be predicted. The remaining increase is due to improved pricing offset by volume declines in almost all products. Inlet rates were lower in 2007 because of two inlet gas compressor outages in the first half of the year as well as our planned fourth quarter turnaround.

Facility Expenses. Facility expenses decreased $0.7 million, or 6%, during the year ended December 31, 2007, relative to 2006. This decrease is for the most part attributable to a utility refund of $3.6 million from a rate case concluded in the first quarter of 2007. Without the refund, facility expenses were higher by $2.9 million, mainly due to increased payroll, costs related to our fourth quarter turnaround and compressor repairs.

Reconciliation of Segment Operating Income to Consolidated Net Income

The following table provides a reconciliation of segment income to our consolidated net income. The ensuing items listed below the "Total segment operating income" line are not allocated to business segments as management does not consider these items allocable to any individual segment: gains (losses) from derivative instruments, selling, general and administrative expenses and depreciation of leasehold improvements at our corporate headquarters. Revenue from MarkWest Hydrocarbon is reflected as revenue from affiliates.

	Year ended December 31,	
	2007	2006
	(in thousands)	
Total segment operating income	$178,611	$141,803
Revenue derivative (loss) gain not allocated to segments	(66,543)	5,632
Facilities expense derivative gain not allocated to segments	12	—
Depreciation not allocated to segments	(270)	(15)
Selling, general and administrative expenses	(51,334)	(44,377)
(Loss) gain on disposal of property, plant and equipment	(7,564)	192
Income from operations	52,912	103,235
Earnings from unconsolidated affiliates	5,309	5,316
Interest income	2,887	962
Interest expense	(38,946)	(40,666)
Amortization of deferred finance costs	(2,717)	(9,094)
Miscellaneous (expense) income	(1,002)	11,100
Income before provision for income tax	18,443	70,853
Provision for income tax	(1,244)	(769)
Net income	$17,199	$70,084

Derivative (Loss) Gain. Loss from derivative instruments increased $72.1 million during the year ended December 31, 2007, relative to 2006. The mark-to-market adjustments of our derivative instruments resulted in a $68.6 million increase in unrealized losses, primarily due to a significant increase in the market price for crude oil. Crude oil is used as a proxy hedge for NGLs (see Item 7A. Quantitative and Qualitative Disclosures About Market Risk). In addition, we recognized an increase in realized losses of $3.5 million from settlements.

Selling, General and Administrative Expenses. Selling, general and administrative expenses increased $7.0 million, or 16%, during the year ended December 31, 2007, relative to 2006. We incurred $6.4 million due to merger related activities in 2007. We expect to incur additional expenses of approximately $2.7 million before the closing of the merger. We also incurred $2.7 million more of labor, benefits and related office expenses due to our expansion initiatives. These increases were offset by a $2.2 million reduction in stock-based compensation expense related primarily to the Participation Plan. In addition, we incurred a one-time charge in 2006 to terminate the old headquarters lease of $0.8 million.

(Loss) gain on disposal of property, plant and equipment. Loss from disposal of property, plant and equipment increased $7.8 million, during the year ended December 31, 2007, relative to 2006. The loss is primarily due to the conveyance of the Maytown facility to Equitable and a write-off of leasehold improvements as a result of the termination of the pipeline lease with Equitable in November 2007.

Interest Income. Interest income increased $1.9 million, during the year ended December 31, 2007, compared to 2006, primarily due to the proceeds received from a rate case concluded in the first quarter of 2007 in our Gulf Coast Business Unit.

Interest Expense. Interest expense decreased $1.7 million, or 4%, during the year ended December 31, 2007, relative to 2006, largely due to increased capitalization of interest related to construction in progress of $3.3 million, versus $0.9 million in 2006. The remaining decrease in interest expense is due to lower outstanding balances under our revolving facility and slightly lower interest rates.

Amortization of Deferred Finance Costs. The amortization related to deferred finance costs decreased $6.4 million during the year ended December 31, 2007, relative to 2006. The decrease is attributable to costs associated with our debt refinancing in the third quarter of 2006. Deferred finance costs are being amortized over the terms of the related obligations, which approximates the effective interest method.

Miscellaneous (Expense) Income. Miscellaneous income decreased $12.1 million during the year ended December 31, 2007, compared to 2006. This decrease was largely a result of a change in insurance recoveries related to our investment in Starfish.

Year Ended December 31, 2006, Compared to Year Ended December 31, 2005

East Texas

	Year ended December 31,	
	2006	**2005**
	(in thousands)	
Revenues	$174,279	$128,267
Operating expenses:		
Purchased product costs	91,637	81,030
Facility expenses	15,683	10,463
Depreciation	7,783	4,836
Amortization of intangible assets	8,244	8,293
Accretion of asset retirement obligations	44	33
Total operating expenses before selling, general and administrative expenses	123,391	104,655
Operating income before selling, general and administrative expenses	$50,888	$23,612

Revenues: Revenues increased $46.0 million, or 36%, during the year ended December 31, 2006, relative to 2005. The increase was due to our Carthage gas processing plant beginning operations on January 1, 2006; the start-up of the Blocker gathering system on March 1, 2006; and increased condensate volumes over the same period a year ago.

Purchased Product Costs: Purchased product costs increased $10.6 million, or 13%, during the year ended December 31, 2006, relative to the comparable period in 2005, primarily due to the start-up of the Carthage gas processing plant.

Facility Expenses: Facility expenses increased $5.2 million, or 50%, during the year ended December 31, 2006, relative to the comparable period in 2005, primarily due to startup of the new Carthage gas processing plant and Blocker gathering system, including the related labor and property taxes.

Depreciation: Depreciation expense increased $2.9 million, or 61%, during the year ended December 31, 2006, relative to the comparable period in 2005, mainly due to the new Carthage gas processing plant and Blocker gathering system.

Oklahoma

	Year ended December 31,	
	2006	2005
	(in thousands)	
Revenues	$207,510	$214,043
Operating expenses:		
Purchased product costs	170,168	193,787
Facility expenses	7,883	4,927
Depreciation	3,007	2,385
Accretion of asset retirement obligations	26	63
Total operating expenses before selling, general and administrative expenses	181,084	201,162
Operating income before selling, general and administrative expenses	$26,426	$12,881

Revenues: Revenues decreased $6.5 million, or 3%, during the year ended December 31, 2006, relative to the comparable period in 2005. The decrease was due primarily due to lower natural gas prices that were partially offset by a 15% increase in gathering volumes from new well connects in 2006.

Purchased Product Cost: Purchased product costs decreased $23.6 million, or 12%, during the year ended December 31, 2006, relative to the comparable period in 2005, primarily as a result of lower natural gas prices.

Facility Expenses: Facility expenses increased $3.0 million, or 60%, during the year ended December 31, 2006, relative to the comparable period in 2005, primarily due to additional compression costs and higher operating taxes.

Depreciation: Depreciation expense increased $0.6 million, or 26%, during the year ended December 31, 2006, relative to the comparable period in 2005, related to additional capital placed in service to accommodate a growing gathering system and new well connects.

Other Southwest

	Year ended December 31,	
	2006	2005
	(in thousands)	
Revenues	$84,595	$107,712
Operating expenses:		
Purchased product costs	67,349	92,602
Facility expenses	5,638	4,990
Depreciation	4,100	3,383
Amortization of intangible assets	—	68
Accretion of asset retirement obligations	20	22
Total operating expenses before selling, general and administrative expenses	77,107	101,065
Operating income before selling, general and administrative expenses	$7,488	$6,647

Revenues: Revenues decreased $23.1 million, or 21%, during the year ended December 31, 2006, relative to the comparable period in 2005. The decrease is mostly attributed to a decrease in natural gas prices, and is slightly offset by an increase in NGL volumes and prices.

Purchased Product Costs: Purchased product costs decreased $25.3 million, or 27%, during the year ended December 31, 2006, relative to the comparable period in 2005 primarily due to a decrease in natural gas prices.

Facility Expenses: Facility expenses increased $0.6 million, or 13%, during the year ended December 31, 2006, relative to the comparable period in 2005. The increase was primarily a result of additional compressor maintenance costs.

Depreciation: Depreciation expense increased $0.7 million, or 21%, during the year ended December 31, 2006, relative to the same period in 2005, due to the addition of new compressors in 2006 and late 2005.

Appalachia

	Year ended December 31,	
	2006	2005
	(in thousands)	
Revenue		
Unaffiliated	$2,027	$1,686
Affiliated	73,636	64,922
Total revenues	75,663	66,608
Operating expenses:		
Purchased product costs	43,648	38,435
Facility expenses	13,997	19,360
Depreciation	3,573	3,187
Accretion of asset retirement obligations	12	41
Total operating expenses before selling, general and administrative expenses	61,230	61,023
Operating income before selling, general and administrative expenses	$14,433	$5,585

Revenues: Total revenues increased $9.1 million, or 14%, during the year ended December 31, 2006, relative to the comparable period in 2005. The increase was primarily a result of higher prices and volumes for our Maytown NGLs in 2006. Higher gas volumes at the Kenova and Cobb plants and higher liquid volumes at the Kenova, Cobb and Boldman plants also contributed to the increase; however, these results were offset slightly by lower gas volumes at Boldman.

Purchased Product Costs: Purchased product costs increased $5.2 million, or 14%, during the year ended December 31, 2006, relative to the comparable period in 2005. The rise in costs is primarily a result of higher product prices. The increase was partially offset by reduced trucking expenses amounting to $1.4 million associated with our continuing repair of the ALPS pipeline in 2005 versus the shutdown of the ALPS pipeline in late 2006.

Facility Expenses: Facility expenses decreased $5.4 million, or 28%, during the year ended December 31, 2006, relative to the comparable period in 2005. These expenses were higher in 2005 due to costs incurred to repair the ALPS pipeline.

Depreciation: Depreciation expense increased $0.4 million, or 12%, during the year ended December 31, 2006, relative to the comparable period in 2005, due to increased capitalized leasehold improvements associated with the ALPS pipeline.

Michigan

	Year ended December 31,	
	2006	2005
	(in thousands)	
Revenues	$13,282	$12,479
Operating expenses:		
Purchased product costs	3,435	3,030
Facility expenses	5,721	6,080
Depreciation	5,015	4,665
Total operating expenses before selling, general and administrative expenses	14,171	13,775
Operating loss before selling, general and administrative expenses	$(889)	$(1,296)

Revenues: Revenues increased $0.8 million, or 6%, during the year ended December 31, 2006, relative to the comparable period in 2005, principally due to an increase in product prices at our processing facility and increased processing fees at the West Shore facility, slightly offset by decreased volumes.

Purchased Product Costs: Purchased product costs increased $0.4 million, or 13%, during the year ended December 31, 2006, relative to the comparable period in 2005, which was a result of higher product prices at our processing facility.

Gulf Coast

	Year ended December 31,	
	2006	2005
	(in thousands)	
Revenues	$68,950	$13,832
Operating expenses:		
Facility expenses	11,190	2,152
Depreciation	6,500	1,078
Amortization of intangible assets	7,803	1,295
Total operating expenses before selling, general and administrative expenses	25,493	4,525
Operating income before selling, general and administrative expenses	$43,457	$9,307

The results of operations at Javelina are based on twelve months of activity for the year ended December 31, 2006, compared to two months of activity beginning in November of 2005, the date of the acquisition.

Revenues: Revenues increased $55.1 million, during the year ended December 31, 2006, compared to the two month period in 2005. The Javelina plant was able to grow revenue in 2006 despite reduced inlet gas from refineries.

Facility Expenses: Facility expenses increased $9.0 million during the year ended December 31, 2006, compared to the two month period in 2005, because the 2006 results include a full year of operations.

Depreciation: Depreciation expense increased $5.4 million during the year ended December 31, 2006, compared to the two month period in 2005, because the results include a full year of operations.

Amortization of intangible assets: Amortization expense increased $6.5 million during the year ended December 31, 2006, compared to the two month period in 2005, because the results include a full year of amortization compared to the stub period in 2005.

Reconciliation of Segment Operating Income to Consolidated Net Income

	Year ended December 31,	
	2006	2005
	(in thousands)	
Total segment operating income	$141,803	$56,736
Derivative gain (loss) not allocated to segments	5,632	(1,851)
Depreciation not allocated to segments	(15)	—
Selling, general and administrative	(44,377)	(21,597)
Gain on disposal of property, plant and equipment	192	24
Income from operations	103,235	33,312
Earnings (losses) from unconsolidated affiliates	5,316	(2,153)
Interest income	962	367
Interest expense	(40,666)	(22,469)
Amortization of deferred finance costs	(9,094)	(6,780)
Miscellaneous income	11,100	78
Income before Texas Margin Tax	$70,853	$2,355
Texas Margin Tax	(769)	—
Net income	$70,084	$2,355

Derivative gain (loss): Derivative gain (loss) increased $7.5 million during the year ended December 31, 2006, compared to the corresponding period in 2005. This increase was due to the mark-to-market adjustments resulting from our electing not to adopt hedge accounting treatment on our derivative instruments. The mark-to-market adjustments resulted in a $6.9 million increase in unrealized gains, and a $0.6 million decrease in realized losses, when comparing 2006 to 2005 results.

Selling, General and Administrative Expense: Selling, general and administrative expenses increased $22.6 million, or 105%, during the year ended December 31, 2006, relative to the comparable period in 2005. The increase is primarily due to higher non-cash, equity-based compensation expense of $12.0 million, primarily due to the Partnership's increased market value; an increase in labor costs of $4.9 million related to increased costs for our existing employees plus the cost of additional personnel necessary to support our growth and strategic objectives; higher insurance expense and taxes of $2.4 million; and a one-time charge to terminate the old headquarters lease of $0.8 million.

Earnings (losses) from Unconsolidated Affiliates: Earnings (losses) from unconsolidated affiliates is primarily related to our investment in Starfish, a joint venture with Enbridge Offshore Pipelines LLC. The Partnership accounts for our 50% interest using the equity method, and the financial results for Starfish are included as earnings from unconsolidated affiliates. During the year ended December 31, 2006, our earnings from unconsolidated affiliates increased $7.5 million, or 347%, relative to the comparable period in 2005. The increase was primarily from resumed operations in 2006 following the shutdown and repairs from the hurricanes in 2005.

Interest Income: Interest income increased $0.6 million, or 162%, during the year ended December 31, 2006, relative to the comparable period in 2005, primarily due to an increase in interest rates earned on invested funds.

Interest Expense: Interest expense increased $18.2 million, or 81%, during the year ended December 31, 2006, relative to the comparable period in 2005, primarily due to increased debt levels resulting from the financing of our 2005 acquisitions and higher interest rates.

Amortization of Deferred Financing Costs (a component of interest expense): Amortization expense increased $2.3 million, or 34%, during the year ended December 31, 2006, relative to the comparable period in 2005, primarily due to costs associated with our debt refinancing completed in the fourth quarter of 2005 and our debt offering in July of 2006. Deferred financing costs are being amortized over the terms of the related obligations, which approximates the effective interest method.

Miscellaneous Income (Expense): The Partnership recognized $11.0 million of income from insurance recoveries, net of Starfish insurance premiums, recovered from damages that occurred as a result of Hurricane Rita.

Texas Margin Tax: The State of Texas passed a new tax law that subjects the Partnership to an entity-level tax on the portion of its income that is generated in Texas. We recorded a deferred tax liability of $0.8 million, related to the Partnership's temporary differences that are expected to reverse in future periods.

Liquidity and Capital Resources

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain and expand existing operations and revenue generating expenditures, interest payments on our senior secured revolving credit facility and Senior Notes, distributions to our unitholders and acquisitions of new assets or businesses. Short-term cash requirements, such as operating expenses, capital expenditures to sustain existing operations and quarterly distributions to our unitholders, are expected to be funded through operating cash flows. Long-term cash requirements for expansion projects and acquisitions are expected to be funded by several sources, including cash flows from operating activities, borrowings under our new revolving credit facility and the issuance of additional equity and debt securities, as appropriate. Cash flows from operating activities will be affected by prevailing economic conditions in our industry, as well as financial, business and other factors, some of which are beyond our control. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit ratings at the time. As a result of the Merger discussed in Item 1. Business, the incentive distribution rights have been eliminated, which will substantially lower our cost of equity capital.

On February 20, 2008, MarkWest Energy Partners, L.P. entered into a credit agreement ("Partnership Credit Agreement"). It provides for a maximum lending limit of $575.0 million for a five-year term. The Partnership Credit Agreement includes a revolving facility of $350.0 million and a $225.0 million term loan, both of which can be repaid at any time without penalty. Under certain circumstances, the revolving facility of the Partnership Credit Agreement can be increased from $350.0 million to $550.0 million. The credit facility is guaranteed by the Partnership and all of the Partnership's subsidiaries, including the Company, and is collateralized by substantially all of the Partnership's assets and those of its subsidiaries. The Partnership utilized borrowings under the $225.0 million term loan of the Partnership Credit Agreement and made an intercompany loan to the Company in the amount of $225.0 million to fund, in part, the redemption of its common stock pursuant to the Merger. In addition, borrowings under the revolving facility portion of the Partnership Credit Agreement were used to finance other payments under the Merger, outstanding amounts due on its old revolver, and repay debt under the Corporation's credit agreement. The Partnership Credit Agreement required the payment of $10.2 million in deferred financing costs. As of February 25, 2008, the Partnership had borrowed $45.5 million under the revolving facility portion of the Partnership Credit Agreement and approximately $258.5 million was available to be borrowed.

The borrowings under the credit facility bear interest at a variable interest rate, plus basis points. The variable interest rate typically is based on the London Inter Bank Offering Rate ("LIBOR"); however, in certain borrowing circumstances the rate would be based on the higher of a) the Federal Funds Rate plus 0.5-1%, and b) a rate set by the Partnership Credit Facility's administrative agent, based on the U.S. prime rate. The basis points correspond to the ratio of the Partnership's Consolidated Funded Debt (as defined in the Partnership Credit Agreement) to Adjusted Consolidated EBITDA (as defined in the Partnership Credit Agreement), ranging from 0.50% to 1.25% for Base Rate loans, and 1.50% to 2.25% for Eurodollar Rate loans. The basis points will increase by 0.50% during any period (not to exceed 270 days) where the Partnership makes an acquisition for a purchase price in excess of $50.0 million ("Acquisition Adjustment Period"). The Partnership will incur a commitment fee on the unused portion of the credit facility at a rate between 30.0 and 50.0 basis points based upon the ratio of consolidated senior debt (as defined in the Partnership Credit Agreement) to consolidated EBITDA (as defined in the Partnership Credit Facility).

At December 31, 2007, the Partnership and its subsidiary, MarkWest Energy Finance Corporation, also have two series of senior notes outstanding, $225.0 million, at a fixed rate of 6.875% which will mature in November 2014 (the "2014 Senior Notes") and $272.2 million, net of unamortized discount of $2.8 million at a fixed rate of 8.5% due July 15, 2016 (the "2016 Senior Notes").

The indenture governing the 2014 Senior Notes and the 2016 Senior Notes limits the activity of the Partnership and its restricted subsidiaries. The indenture 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, 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 Partnership can raise debt and equity securities in the future under a shelf registration statement on Form S-3 that was filed with the SEC and became immediately effective in November 2006.

The Partnership currently has budgeted from $350.0 million to $400.0 million for growth capital expenditures in 2008 and from $5.0 million to $10.0 million of maintenance capital. Growth capital includes expenditures made to expand or increase the efficiency of the existing operating capacity of our assets, or facilitate an increase in volumes within our operations, whether through construction or acquisition. Maintenance capital includes expenditures to replace partially or fully depreciated assets in order to extend their useful lives.

Cash Flow

	December 31,	
	2007	2006
Net cash provided by operating activities	$149,399	$150,977
Net cash used in investing activities	(312,085)	(119,338)
Net cash provided by (used in) financing activities	154,789	(17,342)

Net cash provided by operating activities decreased $1.6 million during the year ended December 31, 2007, relative to 2006. The change resulted mainly from increased selling, general and administrative expenses (excluding non-cash components) of $7.1 million, of which $6.4 million is related to merger costs, and additional margin calls of approximately $19.3 million, offset by increased cash flows generated from operations and a $5.5 million refund from a rate case concluded in the first quarter of 2007. We expect to incur an additional $2.7 million in merger costs during the first quarter of 2008. Margin calls will be less likely to occur as the Partnership Credit Agreement limits our ability to enter into transactions with parties that require such arrangements.

Net cash used in investing activities increased $192.7 million for the year ended December 31, 2007, compared to 2006. The increase was primarily due to capital expenditures. The Partnership used $312.3 million for capital expenditures in 2007, consisting of $308.7 million for growth capital and $3.6 million for maintenance capital.

Net cash provided by financing activities increased $172.1 million for the year ended December 31, 2007, compared to 2006. This increase was primarily due to the net proceeds of $229.5 million from our two private placements of common units discussed below used to fund capital expenditures. In the prior years we received net proceeds of $397.6 million related to a private placement of senior notes and proceeds from a public unit offering but the funds were primarily used to pay down long-term debt. This increase was offset by increased distributions to unitholders of $35.0 million.

On April 9, 2007, we completed a private placement of 4.1 million unregistered common units. The units were issued at a purchase price of $32.98 per unit. The registration statement for these common units was declared effective on July 11, 2007. The sale of units raised net proceeds of approximately $137.7 million, including the general partner's contribution of $2.8 million to maintain its 2% general partner interest and after legal, accounting and other transaction expenses.

On December 18, 2007, we completed a private placement of 2.9 million unregistered common units. The units were issued at a purchase price of $31.50 per unit. The sale of units raised net proceeds of approximately $91.8 million, including the general partner's contribution to maintain its 2% general partner interest and after legal, accounting and other transaction expenses.

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of December 31, 2007, is as follows (in thousands):

	Payment Due by Period				
Type of obligation	Total Obligation	Due in 2008	Due in 2009-2010	Due in 2011-2012	Thereafter
Long-term debt	$555,500	$—	$55,500	$—	$500,000
Interest expense on long-term debt(1)	307,080	42,777	85,554	77,687	101,062
Operating leases	21,172	6,251	4,573	3,725	6,623
Purchase obligations (2)	107,849	88,061	19,788	—	—
Other long-term liabilities reflected on the Consolidated Balance Sheets—					
Asset retirement obligation	1,635	—	—	—	1,635
Other (3)	1,495	—	232	121	1,142
Total contractual cash obligations	$994,731	$137,089	$165,647	$81,533	$610,462

(1) Assumes that our outstanding borrowings at December 31, 2007 remain outstanding until their respective maturity dates and we incur interest expense at 7.09% on the Partnership Credit Facility revolver, 6.875% on the 2014 Senior Notes and 8.5% on the 2016 Senior Notes.

(2) Represents purchase orders and contracts related to purchase of property, plant and equipment.

(3) Primarily represents long-term portion of deferred revenue.

Off-Balance Sheet Arrangements

The Partnership does not engage in off-balance sheet financing activities.

Matters Influencing Future Results

On September 28, 2007, we announced an approximate $100.0 million expansion of the Javelina plant. This expansion involves the installation of a steam methane reformer facility for the recovery of high purity hydrogen. This new facility's production is supported by a 20-year hydrogen supply agreement. Construction of the facility began in the fourth quarter of 2007 and we expect to commence delivering high-purity hydrogen in early 2010. Once operational, the facility, combined with the existing facilities at the Javelina plant will have the capacity to deliver 50 MMcf/d of high-purity hydrogen.

The Partnership completed the Merger with the Company and entered into a new credit agreement on February 21, 2008, as discussed further in Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K. The Merger is considered a downstream merger whereby the Company is viewed as the surviving consolidated entity for accounting purposes rather than the Partnership, which is the surviving consolidated entity for legal purposes. As such, the Merger will be accounted for in the Company's consolidated financial statements as an acquisition of non-controlling interest using the purchase method of accounting. Under this accounting method, the Partnership's accounts, including goodwill, will be adjusted to proportionately step up the book value of certain assets and liabilities. The total fair value of the non-controlling interest to be acquired was the number of non-controlling interest units outstanding on the date the merger closed of 34.5 million valued at the then current per unit market price of the Partnership common units of $31.79.

Our future results will be impacted by the completion of the proportionate step up of the book value of certain assets and liabilities. Depending on the allocation, interest expense, amortization of intangibles and deferred financing costs, depreciation expense and income tax balances could change materially in the future. The purchase price allocation is dependent upon certain valuations and other studies that have not progressed to a stage where there is sufficient information to make a definitive allocation. Therefore, we are unable to predict the impact of the purchase price allocation on our balance sheet and statement of operations.

The cash and the Partnership units distributed to officers and directors of the General Partner for their Class B membership interests in the General Partner were recorded as settlement of the share based payment liability as discussed further in Note 13 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K. In the future, our results will not include compensation for the general partner interests under the Participation Plan. For the year ended December 31, 2007, 2006, and 2005, our results included compensation expense of $10.9 million, $13.5 million and $2.0 million, respectively, related to Participation Plan.

The 2008 LTIP reserves 2.5 million common units for issuance in the future. As discussed further in Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K, on February 21, 2008, 765,000 phantom units were granted to senior executives and other key employees under the 2008 LTIP. The maximum amount of compensation expense for the grant made on February 21, 2008 will range from $9.7 million to $24.3 million. Forty percent (40%) of the total individual grant is based on continuing employment over the three-year vesting period and this represents the minimum in the range. Sixty percent (60%) of the total individual grant is performance-based and is conditional upon the achievement of designated annual financial performance goals established by the Board of Directors. The maximum of the range assumes such conditions will be achieved. The timing of this expense cannot be estimated.

Our affiliate, MarkWest Pioneer, L.L.C. ("Pioneer"), is in a pre-filing process with the Federal Energy Regulatory Commission ("FERC") to construct a new interstate natural gas transmission pipeline. The pipeline will be named the Arkoma Connector Pipeline, and will extend approximately 50 miles from an interconnect with MarkWest's gathering system in the Woodford Shale production area in southeastern Oklahoma to an interconnect with the Midcontinent Express Pipeline in Bennington, Oklahoma.

The Arkoma Connector Pipeline will provide additional outlets for producers in the Woodford Shale as volumes continue to increase. We recently executed agreements with certain producers to provide transportation capacity in excess of 500,000 Mcf/d on the Arkoma Connector Pipeline, and Pioneer will be conducting an open season, prior to submission of our formal application to FERC, in order to gauge additional interest in available capacity.

On February 11, 2008, we agreed to acquire a 20% interest in Centrahoma Operating LLC ("Centrahoma LLC") for $11.6 million, with a right to acquire an additional 20% interest under certain circumstances. Closing on March 3, 2008 is subject to conveyance of certain properties to Centrahoma LLC by the other member and the reimbursement of $0.6 million to the Partnership related to the termination of a virtual joint venture with the other member of the Centrahoma LLC. Centrahoma Operating LLC will own certain processing plants in the Arkoma basin. In addition, MarkWest will sign, at closing, agreements to dedicate certain acreage in the Woodford Shale play to the Centrahoma LLC through March 1, 2018.

The loss to both offshore and onshore assets resulting from Hurricanes Katrina and Rita in 2005 has led to substantial insurance claims within the oil and gas industry. Along with other industry participants, we have seen our insurance costs increase substantially within this region as a result of these developments. We have mitigated a portion of the cost increase by reducing our coverage and adding a broader self-insurance element to our overall coverage.

Seasonality

For the portion of our business that is affected by commodity prices, sales volumes also are affected by various other factors such as fluctuating and seasonal demands for products, changes in transportation and travel patterns and variations in weather patterns from year to year. In general, the Company stores a portion of the propane that is produced in the summer to be sold in the winter months. The Company also stores pre-purchases in the summer of a portion of the natural gas that we are required to replace during the winter in accordance with our Appalachian keep-whole processing agreements.

Effects of Inflation

Inflation did not have a material impact on our results of operations for the years ended December 31, 2007, 2006 or 2005. 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 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 will continue to pass along 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. Estimates are used in accounting for, among other items, valuing identified intangible assets, determining the fair value of derivative instruments, evaluating impairments of long lived assets, establishing estimated useful lives for long-lived assets, valuing asset retirement obligations, and in determining liabilities, if any, for legal contingencies.

The policies and estimates discussed below are considered by management to be critical to an understanding of the Partnership's 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.

Intangible Assets

The Partnership's 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. Fair value is generally calculated as the present value of estimated future cash flows using a risk-adjusted discount rate. The key assumptions include 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 to which the contracts and relationships relate, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions, and maintenance and renewal costs.

Impairment of Long-Lived Assets

The Partnership evaluates its long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. 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.

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.

We determined that an impairment of a system had occurred during the third quarter of 2007. The fair value of the long-lived assets was determined based on management's opinion that the idle assets had no economic value. Therefore, an impairment of long-lived assets of $0.4 million was recognized during year ended December 31, 2007. See Note 10 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for a description of the impairment analysis.

Investment in Starfish

On March 31, 2005, the Partnership acquired its non-controlling, 50% interest in Starfish Pipeline Company, LLC ("Starfish"), which is accounted for under the equity method. Differences between the Partnership's investment and its proportionate share of Starfish's reported equity are amortized based upon the respective useful lives of the assets to which the differences relate.

We believe the equity method is an appropriate means for us 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. We use the following types of evidence of a loss in value to identify a loss in value of an investment that is other than a temporary decline. Examples of a loss in value may be identified by:

- Our belief in the ability to recover the carrying amount of the investment;

- A current fair value of an investment that is less than its carrying amount; and

- Other operational criteria that cause us to believe the investment may be worth less than otherwise accounted for by using the equity method.

Derivative Instruments

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133"), established accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception.

To the extent derivative instruments designated as cash flow hedges are effective, changes in fair value are recognized in other comprehensive income until the underlying hedged item is recognized in earnings. Effectiveness is evaluated by the derivative instrument's ability to offset changes in fair value or cash flows of the underlying hedged item. Any change in the fair value resulting from ineffectiveness is recognized immediately in earnings. Changes in the fair value of derivative instruments designated as fair value hedges, as well as the changes in the fair value of the underlying hedged item, are recognized currently in earnings. Any differences between the changes in the fair values of the hedged item and the derivative instrument represent gains or losses from ineffectiveness. During 2007 and 2006, we did not designate any cash flow or fair value hedges.

In the course of normal operations, the Partnership routinely enters into contracts such as forward physical contracts for the sale of natural gas, propane, and other NGLs, that under SFAS 133, qualify for and are designated as a normal sales contract. Such contracts are exempted from the fair value accounting requirements of SFAS 133 and are accounted for using accrual accounting.

All derivative instruments other than those designated as cash flow hedges, fair value hedges or normal purchase or sale are marked-to-market through revenue or facility expense, the same account as the item being hedged. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices. Values are adjusted to reflect the credit risk inherent in the transaction. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

We included changes in our risk management activities in cash flow from operating activities on the Consolidated Statement of Cash Flows.

Revenue Recognition

The Partnership enters into revenue arrangements where it sells customer's 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, under Emerging Issues Task Force Issue No. 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent, 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 earns a fixed amount and does not take ownership of the gas and/or NGLs.

Earnings Per Unit

Except as discussed in the following paragraph, basic and diluted net income per limited partner unit is calculated by dividing net income, after deducting amounts specially allocated to the general partner's interests, including interests in incentive distribution rights, by the weighted-average number of limited partner common and subordinated units outstanding during the period.

Emerging Issues Task Force Issue No. 03-06, *Participating Securities and the Two-Class Method under FASB Statement No. 128* ("EITF 03-06"), addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity. EITF 03-06 provides that the general partner's interest in net income is to be calculated based on the amount that would be allocated to the general partner if all the net income for the period were distributed, and not on the basis of actual cash distributions for the period.

Incentive Compensation Plans

The Partnership adopted SFAS No. 123 (revised 2004), *Share-Based Payment* ("SFAS 123R"), on January 1, 2006, using the modified prospective method. Prior to adopting SFAS 123R, the Partnership elected to measure compensation expense for equity-based employee compensation plans as prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB 25").

The Partnership issues restricted units under the MarkWest Energy Partners, L.P. Long-Term Incentive Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the Compensation Committee, cash equivalent to the value of a common unit. The restricted units are treated as liability awards under SFAS 123R, and were treated as variable awards under APB 25. The Partnership applied variable accounting under APB 25 for the plan because a phantom unit is an award to employees entitling them to increases in the market value of the Partnership's units subsequent to the date of grant without issuing units to the employees, similar to a stock appreciation right. As a result, the Partnership is required to mark to market the awards at the end of each reporting period. Compensation expense is measured for the phantom unit grants using the market price of MarkWest Energy Partners' common units on the date the units are granted. The fair value of the units awarded is amortized into earnings over the period of service, adjusted quarterly for the change in the fair value of the unvested units granted. The phantom units vest over a stated period.

Vesting is accelerated for certain employees, if specified performance measures are met. The accelerated vesting criteria provisions are based on annualized distribution goals. If the Partnership's distributions are at or above the goal for a certain number of consecutive quarters, vesting of the employee's phantom units is accelerated. The vesting of any phantom units, however, may not occur until at least one year following the date of grant. The general partner of the Partnership may also elect to accelerate the vesting of outstanding awards, which results in an immediate charge to operations for the unamortized portion of the award.

MarkWest Hydrocarbon also entered into arrangements with certain directors and employees of the Company referred to as the Participation Plan. Under this plan, MarkWest Hydrocarbon sold subordinated units of the Partnership or interests in the Partnership's general partner, under a purchase and sale agreement. Both the subordinated unit and general partner interest transactions were considered compensatory arrangements due to the put-and-call provisions and the associated valuation being based on a formula instead of an independent third party valuation. The subordinated units convert to common units after a holding period. Historically, MarkWest Hydrocarbon had settled the subordinated units for cash when individuals left the Company. The general partner interests have no definite term, but historically have been settled for cash when the employee left the Company. Under SFAS 123R, the subordinated units and general partner interests were classified as liability awards. As a result, MarkWest Hydrocarbon was required to mark to market the subordinated unit and general partner interest valuations at the end of each period. Please refer to Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further information about the termination of the Participation Plan.

Under Topic 1-B of the codification of the Staff Accounting Bulletins, *Allocation of Expenses And Related Disclosure In Financial Statements of Subsidiaries, Divisions Or Lesser Business Components of Another Entity*, compensation expense related to services provided by MarkWest Hydrocarbon's employees and directors recognized under the Participation Plan should be allocated to the Partnership. The allocation is based on the percent of time that each employee devotes to the Partnership. Compensation attributable to interests that were sold to individuals who serve on both the Partnership's board of directors of the Partnership's General Partner and on the board of directors of MarkWest Hydrocarbon is allocated equally.

These charges are included in selling, general and administrative expenses and are allocated to the general partner pursuant to the Partnership Agreement. Assuming the compensation cost for the Long-Term Incentive Plan and the

Participation Plan had been determined based on the fair-value methodology of SFAS 123R, the net income and earnings per unit would have been the same as reported on the financial statements for the year ended December 31, 2005.

Recent Accounting Pronouncements

In September 2006 the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"). SFAS 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. SFAS 157 is effective for the Partnership's financial statements as of January 1, 2008. On February 6, 2008 the FASB, approved the partial deferral of SFAS 157 for non-financial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a reoccurring basis (at least annually) until fiscal years beginning after November 15, 2008. The Partnership has elected to defer recognition of items including:

- Nonfinancial assets and liabilities initially measured at fair value in a business combination.
- Reporting units measured at fair value in the first and second steps of a goodwill impairment test as described in paragraphs 19 to 21 of SFAS 142, *Goodwill and Other Intangible Assets* ("SFAS 142").
- Indefinite lived intangible assets measured at fair value for impairment assessment under SFAS 142.
- Long-lived assets measured as fair value for impairment assessment under SFAS 144, *Accounting for Impairment or Disposal of Long Lived Assets.*
- Asset retirement obligations initially measured at fair value under SFAS 143, *Accounting for Asset Retirement Obligations.*
- Liabilities for exit or disposal activities initially measured at fair value under SFAS 146, *Accounting for Costs Associated with Exit or Disposal Activities.*

For the provisions of SFAS 157 adopted, they will not have an impact on the Partnership's financial statements.

In February 2007 the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* ("SFAS 159"), which permits an entity to measure certain financial assets and financial liabilities at fair value. The statement's objective is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS 159, entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis, with a few exceptions, as long as it is applied to the instrument in its entirety. The fair value option election is irrevocable, unless a new election date occurs. SFAS 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity's election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. SFAS 159 is effective for the Partnership as of January 1, 2008. The provisions of SFAS 159 will not have an impact on the Partnership's financial statements.

In December 2007 the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). This statement replaces SFAS 141, *Business Combinations*. The statement provides for how the acquirer recognizes and measures the identifiable assets acquired, liabilities assumed and any non-controlling interest in the acquiree. SFAS 141R provides for how the acquirer recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. The statement determines what information to disclose to enable users to be able to evaluate the nature and financial effects of the business combination. The provisions of SFAS 141R are effective for the Partnership as of January 1, 2009 and do not allow early adoption. The Partnership is currently evaluating the impact of adopting this statement.

In December 2007 the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* ("SFAS 160"). This statement provides that noncontrolling interests in subsidiaries held by parties other than the parent be identified, labeled and presented in the statement of financial position within equity, but separate from the parent's equity. SFAS 160 states that the amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified on the consolidated statement of income. The statement provides for consistency regarding changes in parent ownership including when a subsidiary is deconsolidated. Any retained noncontrolling equity investment in the former subsidiary will be initially measured at fair value. The provisions of SFAS 160 are effective for the Partnership as of January 1, 2009 and do not allow early adoption. The Partnership is currently evaluating the impact of adopting the statement.

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.

Commodity Price Risk

Our primary risk management objective is to reduce downside volatility in our cash flows arising from changes in commodity prices related to future sales of natural gas, NGLs and crude oil. Swaps and futures contracts may allow us to reduce downside volatility in its realized margins as realized losses or gains on the derivative instruments generally are offset by corresponding gains or losses in our sales of physical product. While we largely expect our realized derivative gains and losses to be offset by increases or decreases in the value of our physical sales, we will experience volatility in reported earnings due to the recording of unrealized gains and losses on our derivative positions that will have no offset. The volatility in any given period related to unrealized gains or losses can be significant to our overall results, however, we ultimately expect those gains and losses to be offset when they become realized. A committee, comprised of the senior management team of our general partner, oversees all of our derivative activity.

We utilize a combination of fixed-price forward contracts, fixed-for-floating price swaps and options on the over-the-counter ("OTC") market. We may also enter into futures contracts traded on the NYMEX. Swaps and futures contracts allow us to manage volatility in our margins because corresponding losses or gains on the financial instruments are generally offset by gains or losses in our physical positions.

We enter into OTC swaps with financial institutions and other energy company counterparties. We conduct a standard credit review on counterparties and have agreements containing collateral requirements where deemed necessary. We use standardized swap agreements that allow for offset of positive and negative exposures. We may be subject to margin deposit requirements under OTC agreements (with non-bank counterparties) and NYMEX positions that we plan to meet with letters of credit. Such funding requirements could exceed our letter of credit availability on our credit line. If we were unable to meet these margin calls with letters of credit, we would be forced to sell product to meet the margin calls, or to terminate the corresponding futures contracts. If we are forced to sell product to meet margin calls, we may have to sell product at prices that are not advantageous.

The use of derivative instruments may expose us to the risk of financial loss in certain circumstances, including instances when (i) NGLs do not trade at historical levels relative to crude oil, (ii) sales volumes are less than expected, requiring market purchases to meet commitments, or (iii) our OTC counterparties fail to purchase or deliver the contracted quantities of natural gas, NGLs or crude oil or otherwise fail to perform. To the extent that we enter into derivative instruments, we may be prevented from realizing the benefits of favorable price changes in the physical market. We are similarly insulated, however, against unfavorable changes in such prices. As of February 12, 2008, we currently have hedged approximately 80% of our long positions in 2008 and MarkWest Hydrocarbon currently has hedged approximately 68% of its frac spread positions in 2008.

The following table provides information on our specific derivative positions at December 31, 2007, including the weighted average prices ("WAVG"):

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)	Fair Value (in thousands)
2008	3,150	$67.17	$77.21	$(20,296)
2009	2,925	63.66	69.76	(20,376)
2010	1,514	66.52	74.71	(6,862)

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2008	150	$69.76	$(1,257)
2010	1,173	65.61	(8,143)

We have entered into a contract which gives us an option to fix a component of the utilities cost to an index price on electricity at one of our plant locations. Under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133"), the value of the derivative component of this contract is marked to market based on an index price through facilities expense. The estimated fair value of this contract was approximately $0.1 million current liability and $0.1 million noncurrent asset at December 31, 2007. The estimated fair value of this contract at December 31, 2006 was near zero.

The impact of our commodity derivative instruments on our financial position are summarized below (in thousands):

	December 31,	
	2007	2006
Fair value of derivative instruments:		
Current asset	$99	$4,211
Noncurrent asset	82	2,759
Current liability	(21,658)	(91)
Noncurrent liability	(35,381)	(1,362)

We entered into the following derivative positions subsequent to December 31, 2007:

WTI Crude Puts	Volumes (Bbl/d)	WAVG Floor (Per Bbl)
2008 (Feb through Dec)	3,346	$80.00
2009	2,413	80.00
2010	1,191	80.00
2011	1,818	80.00

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)
2011	1,706	$80.00	$104.50

The following table provides information on MarkWest Hydrocarbon's specific derivative positions at December 31, 2007:

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2008	18,465	$8.38	$(2,195)
2009	17,561	7.98	3,440
2010	10,143	8.27	1,209

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2008	84,207	$1.13	$(13,287)

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2008	14,292	$1.60	$(2,552)

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2008	19,745	$1.30	$(3,728)

Isobutane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2008	6,165	$1.32	$(1,186)

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2008	1,368	$62.79	$(14,113)
2009	3,313	66.38	(25,124)
2010	2,284	68.52	(13,429)
2011 (through Mar 31)	2,351	71.27	(2,725)

MarkWest Hydrocarbon has a contract with one of the largest producers in the Appalachia region which creates a floor on the frac spread that can be realized on a specified volume purchased. Under SFAS 133, the value of this contract is marked based on an index price through purchased product costs. At December 31, 2007, the fair value of this contract was recorded as a current liability of $9.4 million and a noncurrent liability of $6.7 million.

The impact of MarkWest Hydrocarbon's commodity derivative instruments on its standalone financial position are summarized below (in thousands):

	December 31, 2007	December 31, 2006
Fair value of derivative instruments:		
Current asset	$9,342	$5,727
Noncurrent asset	5,332	35
Current liability	(55,768)	(7,385)
Noncurrent liability	(48,670)	(98)

MarkWest Hydrocarbon entered into the following derivative positions subsequent to December 31, 2007:

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)
2011	14,662	$8.88

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)
2011	2,447	$91.54
2012 (through Jan 31)	2,142	91.50

Management periodically estimates the effects of its hedge program and further changes in crude oil prices on the cash flow from operations, including MarkWest Hydrocarbon, for the year-ended December 31, 2008.

Management's analysis considers a hypothetical change in oil prices, derivative instruments outstanding as of February 28, 2008, no change in natural gas prices, and production estimated through December 31, 2008.

- As crude oil prices moves from $90/Bbl to $80/Bbl, our operating cash flow decreases approximately $1.5 million for every $1/Bbl decrease in crude oil prices;
- As crude oil prices moves from $80/Bbl to $65/Bbl, our operating cash flow decreases approximately $1.1 million for every $1/Bbl decrease in crude oil prices; and
- As crude oil prices moves from $65/Bbl to $60/Bbl, our operating cash flow decreases approximately $0.7 million for every $1/Bbl decrease in crude oil prices.

Management's analysis also considers a hypothetical change in natural gas prices, derivative instruments outstanding as of February 28, 2008, no change in crude oil prices, and production estimated through December 31, 2008.

- As natural gas prices increase by $1.00/MMbtu in any price range, our operating cash flow decreases approximately $1.9 million.

We consider the stated hypothetical change in commodity prices to be reasonable given current and historic market performance. The sensitivity analysis presented does not consider the actions management may take to mitigate our exposure to changes, nor does it consider the effects that such hypothetical adverse changes may have on overall economic activity. Actual changes in market prices may differ from hypothetical changes. The effect of the stated theoretical change represents potential losses in our condensed consolidated financial position and results of operations.

Interest Rate

Our primary interest rate risk exposure results from the revolving portion of the partnership credit facility that has a borrowing capacity of $250.0 million and was entered into on December 29, 2005. 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.

Long-term Debt	Interest Rate	Lending Limit	Due Date	Outstanding at December 31, 2007
Partnership Credit Facility(1)	Variable	$250.0 million	December 29, 2010	$55.5 million
2014 Senior Notes.........................	Fixed	$225.0 million	November, 2014	$225.0 million
2016 Senior Notes.........................	Fixed	$275.0 million	July, 2016	$275.0 million

(1) The partnership credit facility was replaced by the Partnership Credit Agreement dated February 20, 2008. See Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information.

Based on our overall interest rate exposure at December 31, 2007, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our credit facility would change earnings by approximately $0.6 million over a 12-month period.

ITEM 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

All omitted 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, 2007 and 2006, and the related consolidated statements of operations, changes in capital and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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 Partnership's internal control over financial reporting as of December 31, 2007, 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 29, 2008 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 29, 2008

MARKWEST ENERGY PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$26,505	$34,402
Receivables, net of allowances of $160 and $118, respectively	110,154	86,126
Receivables from affiliate	8,582	4,654
Inventories	3,118	3,593
Fair value of derivative instruments	99	4,211
Other assets	20,893	3,047
Total current assets	169,351	136,033
Property, plant and equipment	965,234	655,749
Less: Accumulated depreciation	(141,497)	(104,863)
Total property, plant and equipment, net	823,737	550,886
Other assets:		
Investment in Starfish	58,709	64,240
Intangibles and other assets, net of accumulated amortization of $45,753 and $29,080, respectively	326,722	344,066
Deferred financing costs, net of accumulated amortization of $7,804 and $5,326, respectively	13,190	15,753
Fair value of derivative instruments	82	2,759
Other long-term assets	1,043	1,043
Total other assets	399,746	427,861
Total assets	$1,392,834	$1,114,780
LIABILITIES AND CAPITAL		
Current liabilities:		
Accounts payable	$103,160	$86,479
Payables to affiliate	4,229	1,950
Accrued liabilities	60,038	43,255
Fair value of derivative instruments	21,658	91
Total current liabilities	189,085	131,775
Long-term debt, net of original issue discount of $2,805 and $3,135, respectively	552,695	526,865
Deferred taxes	1,220	769
Fair value of derivative instruments	35,381	1,362
Other long-term liabilities	3,130	1,360
Commitments and contingencies (see Note 17)		
Capital:		
General partner	12,241	9,631
Limited partners:		
Common unitholders (39,358 and 31,166 units issued and outstanding at December 31, 2007 and 2006, respectively)	599,082	442,447
Subordinated unitholders (0 and 1,200 units issued and outstanding at December 31, 2007 and 2006, respectively)	—	571
Total capital	611,323	452,649
Total liabilities and capital	$1,392,834	$1,114,780

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,		
	2007	2006	2005
Revenue:			
Unaffiliated parties	$594,441	$550,643	$478,019
Affiliates	74,981	73,636	64,922
Derivative (loss) gain	(66,543)	5,632	(1,851)
Total revenue	602,879	629,911	541,090
Operating expenses:			
Purchased product costs	358,720	376,237	408,884
Facility expenses	75,036	60,112	47,972
Selling, general and administrative expenses	51,334	44,377	21,597
Depreciation	40,171	29,993	19,534
Amortization of intangible assets	16,672	16,047	9,656
Loss (gain) on disposal of property, plant and equipment	7,564	(192)	(24)
Accretion of asset retirement obligations	114	102	159
Impairments	356	—	—
Total operating expenses	549,967	526,676	507,778
Income from operations	52,912	103,235	33,312
Other income (expense):			
Earnings (losses) from unconsolidated affiliates	5,309	5,316	(2,153)
Interest income	2,887	962	367
Interest expense	(38,946)	(40,666)	(22,469)
Amortization of deferred financing costs and original issue discount (a component of interest expense)	(2,717)	(9,094)	(6,780)
Miscellaneous (expense) income	(1,002)	11,100	78
Income before provision for income tax	18,443	70,853	2,355
Provision for income tax expense	(1,244)	(769)	—
Net income	$17,199	$70,084	$2,355
Interest in net income:			
General partner	$12,821	$(843)	$2,113
Limited partners	$4,378	$70,927	$242
Net income per limited partner unit (See Note 2):			
Basic	$0.12	$2.45	$0.01
Diluted	$0.12	$2.44	$0.01
Weighted-average units outstanding:			
Basic	35,496	28,966	21,790
Diluted	35,657	29,098	21,858
Distributions declared per limited partner unit	$2.09	$1.79	$1.60

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

MARKWEST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN CAPITAL AND COMPREHENSIVE INCOME

(in thousands)

	PARTNERS' CAPITAL					Accumulated Other Comprehensive	
	Limited Partners						
	Common		Subordinated		General		
	Units	Amount	Units	Amount	Partner	(Loss) Income	Total
Balance at December 31, 2004	15,283	$227,483	6,000	$8,813	$5,160	$(314)	$241,142
Issuance of units in private placement, net of offering costs	4,438	97,518	—	—	1,990	—	99,508
Common units issued for vested restricted units, including contribution by MarkWest Energy GP, LLC	18	432	—	—	9	—	441
Contributions by MarkWest Energy GP, LLC	—	—	—	—	404	—	404
Common unit registration costs	—	(45)	—	—	—	—	(45)
Subordinated units converted to common units	2,400	496	(2,400)	(496)	—	—	—
Participation Plan compensation expense allocated from MarkWest Hydrocarbon	—	—	—	—	2,055	—	2,055
Distributions to partners	—	(24,866)	—	(9,190)	(4,943)	—	(38,999)
Net (loss) income	—	(136)	—	378	2,113	—	2,355
Unrealized gains on commodity derivative instruments accounted for as hedges	—	—	—	—	—	314	314
Comprehensive income							2,669
Balance at December 31, 2005	22,139	300,882	3,600	(495)	6,788	—	307,175
Common units issued for vested restricted units	27	637	—	—	—	—	637
Issuance of units in public offering, net of offering costs	6,600	123,410	—	—	2,524	—	125,934
Subordinated unites converted to common units	2,400	203	(2,400)	(203)	—	—	—
Contributions by MarkWest Energy GP, LLC	—	—	—	—	276	—	276
Participation Plan compensation expense allocated from MarkWest Hydrocarbon	—	—	—	—	13,485	—	13,485
Distributions to partners	—	(46,481)	—	(5,862)	(12,599)	—	(64,942)
Net income (loss)	—	63,796	—	7,131	(843)	—	70,084
Balance at December 31, 2006	31,166	442,447	1,200	571	9,631	—	452,649
Common units issued for vested restricted units, including contribution by MarkWest Energy GP, LLC	41	1,281	—	—	39	—	1,320
Issuance of units in private offering, net of offering costs	6,951	224,951	—	—	4,591	—	229,542
Conversion of subordinated units	1,200	(259)	(1,200)	259		—	—
Common unit registration costs	—	(307)	—	—	(6)	—	(313)
Participation Plan compensation expense allocated from MarkWest Hydrocarbon	—	—	—	—	10,880	—	10,880
Distributions to partners	—	(72,391)	—	(1,848)	(25,715)	—	(99,954)
Net income.	—	3,360	—	1,018	12,821	—	17,199
Balance at December 31, 2007	39,358	$599,082	—	$—	$12,241	$—	$611,323

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

MARKWEST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	December 31, 2007	2006	2005
Net income	$17,199	$70,084	$2,355
Adjustments to reconcile net income to net cash provided by operating activities (net of acquisitions):			
Depreciation	40,171	29,993	19,534
Amortization of intangible assets	16,672	16,047	9,656
Amortization of deferred financing costs and original issue discount	2,717	9,094	6,780
Accretion of asset retirement obligation	114	102	159
Impairments	356	—	—
Restricted unit compensation expense	2,080	1,686	1,076
Participation Plan compensation expense	10,880	13,485	2,055
Equity in (earnings) loss of unconsolidated affiliates	(5,309)	(5,316)	2,153
Distributions from equity investment	10,840	—	1,849
Unrealized loss (gain) on derivative instruments	62,376	(6,245)	657
Loss (gain) on disposal of property, plant and equipment	7,564	(192)	(24)
Loss on sale of equity investee	—	26	—
Deferred taxes	451	769	—
Other	(215)	93	(28)
Changes in operating assets and liabilities, net of working capital acquired:			
Receivables	(24,028)	18,912	11,216
Receivables from affiliates	(3,928)	3,286	(2,094)
Inventories	(7)	(39)	(1,318)
Other assets	(16,989)	3,043	(6,676)
Accounts payable and accrued liabilities	26,176	(2,380)	(1,678)
Payables to affiliates	2,279	(1,471)	(3,582)
Net cash provided by operating activities	149,399	150,977	42,090
Cash flows from investing activities:			
Acquisitions	29	(21,389)	(356,917)
Investment in Starfish	—	(21,237)	(41,688)
Capital expenditures	(312,310)	(77,387)	(70,750)
Proceeds from sale of equity investee	—	150	—
Proceeds from disposal of property, plant and equipment	196	525	47
Net cash flows used in investing activities	(312,085)	(119,338)	(469,308)
Cash flows from financing activities:			
Proceeds from long-term debt	477,300	157,524	893,000
Payments of long-term debt	(451,800)	(506,524)	(514,000)
Proceeds from private placement of senior notes	—	271,700	—
Payments for debt issuance costs, deferred financing costs and registration costs	(338)	(6,310)	(11,853)
Proceeds from private placements, net	229,542	5,000	94,508
Proceeds from public unit offering, net	—	125,934	—
Contributions by MarkWest Energy GP, LLC	39	276	404
Distributions to unitholders	(99,954)	(64,942)	(38,999)
Net cash flows provided by (used in) financing activities	154,789	(17,342)	423,060
Net (decrease) increase in cash	(7,897)	14,297	(4,158)
Cash and cash equivalents at beginning of year	34,402	20,105	24,263
Cash and cash equivalents at end of year	$26,505	$34,402	$20,105
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest, net of amounts capitalized	$39,224	$31,784	$22,112
Supplemental schedule of non-cash investing and financing activities:			
Accrued property, plant and equipment	$16,913	$10,866	$1,602
Property, plant and equipment asset retirement obligation	$253	$64	$561
Deferred offering costs payable	$—	$—	$215
Accrued amounts due to Javelina sellers and Starfish	$—	$—	$6,888
Accrued private placement proceeds	$—	$—	$5,000

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

MARKWEST ENERGY PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

MarkWest Energy Partners, L.P. ("MarkWest Energy Partners") was formed on January 25, 2002, as a Delaware limited partnership. The Partnership and its wholly owned subsidiary, MarkWest Energy Operating Company, L.L.C. (the "Operating Company"), were formed to acquire, own and operate most of the assets, liabilities and operations of MarkWest Hydrocarbon, Inc.'s Midstream Business (the "Midstream Business"). MarkWest Energy Partners is engaged in the gathering, processing and transmission of natural gas; the transportation, fractionation and storage of natural gas liquids and the gathering and transportation of crude oil. MarkWest Energy Partners has established a significant presence in the Southwest through strategic acquisitions and strong organic growth opportunities stemming from those acquisitions. MarkWest Energy Partners is also one of the largest processors of natural gas in the Appalachian Basin, one of the country's oldest natural gas producing regions. Finally, MarkWest Energy Partners processes natural gas and owns a crude oil transportation pipeline in Michigan. MarkWest Energy Partners' principal executive office is located in Denver, Colorado.

On February 21, 2008, MarkWest Energy Partners, L.P. consummated the transactions contemplated by its plan of redemption and merger with MarkWest Hydrocarbon, Inc. (the "Company" or "MarkWest Hydrocarbon") and MWEP, L.L.C., a wholly owned subsidiary of the Partnership. A discussion of the merger and its accounting impact on the Partnership is described in Note 22.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements include the accounts of MarkWest Energy Partners, L.P., and all of its majority-owned subsidiaries (collectively, the "Partnership"), and have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). 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.

On February 28, 2007 the Partnership completed a two-for-one split of the Partnership's common units, whereby holders of record at the close of business on February 22, 2007 received one additional common unit for each common unit owned on that date. For all periods presented prior to February 22, 2007, all references to the number of units and per unit net income and distribution amounts included in this report have been adjusted to give the effect to the unit split.

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, evaluating impairments of long lived assets, establishing estimated useful lives for long-lived assets, estimating revenues and expense accruals, 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.

Inventories

Inventories are valued at the lower of weighted average cost or market. Inventories consisting primarily of crude oil and unprocessed natural gas are valued based on the cost of the raw material. Processed natural gas inventories include material, labor and overhead. Shipping and handling costs are included in operating expenses.

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-term 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 the following estimated useful lives:

Asset Class	Range of Estimated Useful Lives
Buildings	20 - 25 years
Gas gathering facilities	20 - 25 years
Gas processing plants	20 - 25 years
Fractionation and storage facilities	20 - 25 years
Natural gas pipelines	20 - 25 years
Crude oil pipelines	20 - 25 years
NGL transportation facilities	20 - 25 years
Equipment and other	3 - 10 years

The Partnership recognizes the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred, with an offsetting increase in the carrying amount of the related long-lived asset. The recognition of an asset retirement obligation requires that management make numerous estimates, assumptions and judgments regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates, and future advances in technology. In periods subsequent to initial measurement of the liability, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Over time, the liability is accreted to its future value, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss. The Partnership adopted the Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"), on January 1, 2005. FIN 47 clarified the accounting for conditional asset retirement obligations under Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"). A conditional asset retirement obligation is an unconditional legal obligation to perform an 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. FIN 47 requires an entity to recognize a liability for a conditional asset retirement obligation if the amount can be reasonably estimated. Adopting FIN 47 had an immaterial impact on the Partnership.

Investment in Starfish

On March 31, 2005, the Partnership acquired its non-controlling, 50% interest in Starfish Pipeline Company, LLC ("Starfish") for $41.7 million, which is accounted for under the equity method. Differences between the Partnership's investment and its proportionate share of Starfish's reported equity are amortized based upon the respective useful lives of the assets to which the differences relate. The Partnership's share of Starfish's income was $5.3 million in 2007 and 2006 compared to a loss of $2.2 million in 2005.

Management's accounting policy requires an evaluation of operating losses, if any, and other factors that may have occurred, that may be indicative of a decrease in value of the investment which is other than temporary, and which should be recognized even though the decrease in value is in excess of what would otherwise be recognized by application of the equity method. The evaluation determines if an equity method investment should be impaired and that an impairment, if any, is fairly reflected in these financial statements.

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. It uses the following types of evidence of a loss in value to identify a loss in value of an investment that is other than a temporary decline. Examples of a loss in value may be identified by:

- An inability to recover the carrying amount of the investment;

- A current fair value of an investment that is less than its carrying amount; and
- Other operational criteria that cause management to believe the investment may be worth less than otherwise accounted for by using the equity method.

Intangible Assets

The Partnership's 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. Fair value is generally calculated as the present value of estimated future cash flows using a risk-adjusted discount rate. The key assumptions include 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 to which the contracts and relationships relate, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions, and maintenance and renewal costs.

Impairment of Long-Lived Assets

The Partnership evaluates its long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. 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.

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, included in Other assets in the Consolidated Balance Sheets, are amortized over the estimated lives of the related obligations or, in certain circumstances, accelerated if the obligation is refinanced, using the straight line method which approximates the effective interest method.

Deferred income

Deferred income represents prepayments received in revenue generating contracts. In certain cases, the Partnership received prepayments under fixed fee contracts to deliver NGLs at a future date. Deferred income is recognized as revenue upon delivery of the product. In other cases, the Partnership received prepayments related to the construction of gathering facilities to transport the producer's gas from certain delivery points. Deferred income is generally recognized into revenue over the term of the gathering contract. Deferred income is reported in Accrued Liabilities and Other Long Term Liabilities in the accompanying Balance Sheets.

Derivative Instruments

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133"), established accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception.

To the extent derivative instruments designated as cash flow hedges are effective, changes in fair value are recognized in other comprehensive income until the underlying hedged item is recognized in earnings. Effectiveness is evaluated by the derivative instrument's ability to offset changes in fair value or cash flows of the underlying hedged item. Any change in the fair value resulting from ineffectiveness is recognized immediately in earnings. Changes in the fair value of derivative instruments designated as fair value hedges, as well as the changes in the fair value of the underlying hedged item, are recognized currently in earnings. Any differences between the changes in the fair values of the hedged item and the derivative instrument represent gains or losses from ineffectiveness. During 2007 and 2006, we did not designate any cash flow or fair value hedges.

In the course of normal operations, the Partnership routinely enters into contracts such as forward physical contracts for the sale of natural gas, propane, and other NGLs, that under SFAS 133, qualify for and are designated as a normal sales contract. Such contracts are exempted from the fair value accounting requirements of SFAS 133 and are accounted for using accrual accounting.

All derivative instruments other than those designated as cash flow hedges, fair value hedges or normal purchase or sale are marked to market through revenue or facility expense, the same account as the item hedged. Changes in risk management activities are reported in cash flow from operating activities on the Consolidated Statement of Cash Flows.

Fair Value of Financial Instruments

Management believes the carrying amount of financial instruments, including cash, accounts receivable, accounts payable, and accrued expenses approximates fair value because of the short-term maturity of these instruments. Management believes the carrying value of the Partnership's Credit Facility (see Note 11) approximates fair value due to its variable interest rates. The estimated fair value of the Senior Notes (see Note 11) was approximately $490.7 million and $499.8 million at December 31, 2007 and 2006, respectively, based on quoted market prices. Derivative instruments not designated as hedges (see Note 12) are recorded at fair value, based on available market information.

Revenue Recognition

The Partnership generates the majority of its revenues from natural gas gathering, processing and transmission; NGL transportation, fractionation and storage; and crude oil gathering and transportation. It enters into variety of contract types. In many cases, the Partnership provides services under contracts that contain a combination of more than one of the arrangements described below. The Partnership provides services under the following different types of arrangements (all of which constitute midstream energy operations):

- *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; transportation, fractionation and storage of NGLs; and gathering and transportation of crude oil. The revenue the Partnership earns from these arrangements is 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.

- *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 based on an index price. In other cases, instead of remitting cash payments to the producer, the Partnership will deliver an agreed-upon percentage of the residue gas and NGLs to the producer and sell the volumes the Partnership keeps to third parties at market prices.

- *Percent-of-index arrangements*—Under percent-of-index arrangements, the Partnership will purchase 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 will then gather and deliver the natural gas to pipelines where the Partnership will resell the natural gas at the index price, or at a different percentage discount to the index price.

- *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.

- *Settlement margin*—Typically, 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 efficiently than specified per contract allowance, the Partnership is entitled to retain the difference 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. Under all of the arrangements, revenue is recognized at the time the product is delivered and title is transferred. 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 four 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. To the extent the Partnership retains its equity liquids as inventory, delivery occurs when the inventory is subsequently sold and title is transferred to the third party purchaser.

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. The fees are generally due within ten days of delivery or services rendered. For other arrangements, the amount of revenue is determinable when the sale of the applicable product has been completed upon delivery and transfer of tile. Proceeds from the sale of products are generally due in ten days.

Collectibility is reasonably assured. Collectibility is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (e.g. cash position and credit rating) and their ability to pay. If collectibility 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 customer's 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, under Emerging Issues Task Force ("EITF") Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, 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 earns a fixed amount and does not take ownership of the gas and/or NGLs.

Gas volumes received may be different from gas volumes delivered, resulting in gas imbalances. The Partnership records a receivable or payable for such imbalances based upon the contractual terms of the purchase agreements. The Partnership had an imbalance payable of $0.9 million at December 31, 2007 and 2006, recorded in accrued liabilities in the accompanying consolidated Balance Sheets. The Partnership had an imbalance receivable of $1.7 million and $2.7 million at December 31, 2007 and 2006, respectively, recorded in other receivables in the accompanying consolidated Balance Sheets. Revenues for the transportation of crude are based upon regulated tariff rates and the related transportation volumes and are recognized when delivery of crude is made to the purchaser or other common carrier pipeline. As described above, changes in the fair value of commodity derivative instruments are recognized currently in revenue.

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. Most of the estimated accruals are reversed in the following month when actual information is received from third parties and the Partnership's internal records have been reconciled.

Incentive Compensation Plans

The Partnership adopted SFAS No. 123 (revised 2004), *Share-Based Payment* ("SFAS 123R"), on January 1, 2006, using the modified prospective method. Prior to adopting SFAS 123R, the Partnership elected to measure compensation expense for equity-based employee compensation plans as prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB 25").

The Partnership issues restricted units under the MarkWest Energy Partners, L.P. Long-Term Incentive Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the Compensation Committee, cash equivalent to the value of a common unit. The restricted units are treated as liability awards under SFAS 123R, and were treated as variable awards under APB 25. The Partnership applied variable accounting under APB 25 for the plan because a phantom unit is an award to employees entitling them to increases in the market value of the Partnership's units subsequent to the date of grant without issuing units to the employees, similar to a stock appreciation right. As a result, the Partnership is required to mark to market the awards at the end of each reporting period. Compensation expense is measured for the phantom unit grants using the market price of MarkWest Energy Partners' common units on the date the units are granted. The fair value of the units awarded is amortized into earnings over the period of service, adjusted quarterly for the change in the fair value of the unvested units granted. The phantom units vest over a stated period.

Vesting is accelerated for certain employees, if specified performance measures are met. The accelerated vesting criteria provisions are based on annualized distribution goals. If the Partnership's distributions are at or above the goal for a certain number of consecutive quarters, vesting of the employee's phantom units is accelerated. The general partner of the Partnership may also elect to accelerate the vesting of outstanding awards, which results in an immediate charge to operations for the unamortized portion of the award.

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

MarkWest Hydrocarbon entered into arrangements with certain directors and employees of the Company referred to as the Participation Plan. Under this plan, the Company sold subordinated units of the Partnership or interests in the Partnership's general partner, under a purchase and sale agreement. Both the subordinated unit and general partner interest transactions were considered compensatory arrangements due to the put-and-call provisions and the associated valuation being based on a formula instead of an independent third party valuation. The subordinated units converted to common units after a holding period. Historically, the Company has settled the subordinated units for cash when individuals left the Company. The general partner interests have no definite term, but historically have been settled for cash when the employee left the Company. Under SFAS 123R, the subordinated units and general partner interests were classified as liability awards. As a result, the Company was required to mark to market the subordinated unit and general partner interest valuations at the end of each period. Please refer to Note 22 for further information about the termination of the Participation Plan.

Under Topic 1-B of the codification of the Staff Accounting Bulletins, *Allocation of Expenses and Related Disclosure in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity*, some portion of compensation expense related to services provided by MarkWest Hydrocarbon's employees and directors recognized under the Participation Plan should be allocated to the Partnership. The allocation is based on the percent of time each employee devotes to the Company. Compensation attributable to interests sold to individuals who serve on both the board of MarkWest Hydrocarbon and the Partnership's Board of Directors of the Partnership's General Partner is allocated equally.

These charges are included in selling, general and administrative expenses and are allocated to the general partner pursuant to the Partnership Agreement. Assuming the compensation cost for the Long-Term Incentive Plan and the Participation Plan had been determined based on the fair-value methodology of SFAS 123R, the net income and earnings per unit would have been the same as reported on the financial statements for the year ended December 31, 2005.

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 aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined as the Partnership does not have access to information about each partner's tax attributes related to the Partnership.

The Partnership is a taxable entity under certain state jurisdictions. The Partnership accounts for state income taxes under the asset and liability method pursuant to SFAS No. 109, *Accounting for Income Taxes* ("SFAS 109"). Under SFAS 109, deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply 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 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 write down the deferred tax assets to their net realizable value.

The Partnership adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"), on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS 109. Specifically, the pronouncement prescribes a "more likely than not" recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. The adoption of FIN 48 did not have a material effect on the Partnership's financial position or results of operations.

Comprehensive Income (loss)

Comprehensive income (loss) includes net income and other comprehensive income (loss), which includes unrealized gains and losses on commodity or interest rate derivative financial instruments accounted for as hedges.

Earnings Per Unit

Except as discussed in the following paragraph, basic and diluted net income per limited partner unit is calculated by dividing net income, after deducting amounts specially allocated to the general partner's interests, including interests in incentive distribution rights, by the weighted-average number of limited partner common and subordinated units outstanding during the period.

EITF No. 03-06, *Participating Securities and the Two-Class Method under FASB Statement No. 128,* ("EITF 03-06") addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity. EITF 03-06 provides that the general partner's interest in net income is to be calculated based on the amount that would be allocated to the general partner if all the net income for the period were distributed, and not on the basis of actual cash distributions for the period.

The following table sets forth the computation of basic and diluted earnings per limited partner unit, as adjusted for the February 28, 2007 two-for-one unit split. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents in 2007, 2006 and 2005 (in thousands, except per unit data):

	Year ended December 31,		
	2007	2006	2005
Numerator for basic and diluted earnings per limited partner unit:			
Net income	$17,199	$70,084	$2,355
Less:			
General partner's incentive distribution paid	(23,716)	(11,301)	(4,163)
Sub-total	(6,517)	58,783	(1,808)
Plus:			
Allocated depreciation expense attributable to the general partners contribution for construction of the Cobb Gas Extraction Plant	106	106	—
Participation plan allocation	10,880	13,485	2,055
Net income before GP interest	4,469	72,374	247
Less:			
General partner's 2% interest	(91)	(1,447)	(5)
Net income available to limited partners under EITF 03-6	$4,378	$70,927	$242
Denominator:			
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	35,496	28,966	21,790
Effect of dilutive securities:			
Weighted-average of restricted units outstanding	161	132	68
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	35,657	29,098	21,858
Net income per limited partner unit:			
Basic	$0.12	$2.45	$0.01
Diluted	$0.12	$2.44	$0.01

Recent Accounting Pronouncements

In September 2006 the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"). SFAS 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. SFAS 157 is effective for the Partnership's financial statements as of January 1, 2008. On February 6, 2008 the FASB, approved the partial deferral of SFAS 157 for non-financial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a reoccurring basis (at least annually) until fiscal years beginning after November 15, 2008. The Partnership has elected to defer recognition of items including:

- Nonfinancial assets and liabilities initially measured at fair value in a business combination.
- Reporting units measured at fair value in the first and second steps of a goodwill impairment test as described in paragraphs 19 to 21 of SFAS 142, *Goodwill and Other Intangible Assets* ("SFAS 142").
- Indefinite lived intangible assets measured at fair value for impairment assessment under SFAS 142.
- Long-lived assets measured as fair value for impairment assessment under SFAS 144, *Accounting for Impairment or Disposal of Long Lived Assets.*
- Asset retirement obligations initially measured at fair value under SFAS 143.
- Liabilities for exit or disposal activities initially measured at fair value under SFAS 146 *Accounting for Costs Associated with Exit or Disposal Activities.*

For the provisions of SFAS 157 adopted as of January 1, 2008, they will not have an impact on the Partnership's financial statements.

In February 2007 the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* ("SFAS 159"), which permits an entity to measure certain financial assets and financial liabilities at fair value. The statement's objective is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS 159, entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis, with a few exceptions, as long as it is applied to the instrument in its entirety. The fair value option election is irrevocable, unless a new election date occurs. SFAS 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity's election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. SFAS 159 is effective for the Partnership as of January 1, 2008. The provisions of SFAS 159 will not have an impact on the Partnership's financial statements.

In December 2007 the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). This statement replaces SFAS 141, *Business Combinations*. The statement provides for how the acquirer recognizes and measures the identifiable assets acquired, liabilities assumed and any non-controlling interest in the acquiree. SFAS 141R provides for how the acquirer recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. The statement determines what information to disclose to enable users to be able to evaluate the nature and financial effects of the business combination. The provisions of SFAS 141R are effective for the Partnership as of January 1, 2009 and do not allow early adoption. The Partnership is currently evaluating the impact of adopting this statement.

In December 2007 the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* ("SFAS 160"). This statement provides that noncontrolling interests in subsidiaries held by parties other than the parent be identified, labeled and presented in the statement of financial position within equity, but separate from the parent's equity. SFAS 160 states that the amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified on the consolidated statement of income. The statement provides for consistency regarding changes in parent ownership including when a subsidiary is deconsolidated. Any retained noncontrolling equity investment in the former subsidiary will be initially measured at fair value. The provisions of SFAS 160 are effective for the Partnership as of January 1, 2009 and do not allow early adoption. The Partnership is currently evaluating the impact of adopting the statement.

3. Acquisitions

During 2006 and 2005, the Partnership completed the following acquisitions. Each acquisition was accounted for under the purchase method. The assets acquired and liabilities assumed were recorded at the estimated fair market values as of the acquisition date. The preliminary allocation of assets and liabilities may be adjusted to reflect the final determined amounts during a short period of time following the acquisition. The results of operations from these acquisitions are included in our consolidated financial statements from the acquisition date.

Santa Fe Gathering Acquisition

On December 29, 2006, the Partnership purchased 100% of the ownership interest in Santa Fe Gathering, L.L.C. for $15.0 million subject to working capital adjustments. The gathering system is located in Roger Mills and Beckham Counties, Oklahoma. The Grimes system was constructed in May 2005 to gather from growing production fields.

Javelina Acquisition

On November 1, 2005, the Partnership acquired equity interests in Javelina Company, Javelina Pipeline Company and Javelina Land Company, L.L.C., which were 40%, 40% and 20%, respectively, owned by subsidiaries of El Paso Corporation, Kerr-McGee Corporation and Valero Energy Corporation. The Partnership paid consideration of $357.0 million, plus $41.8 million for net working capital that included approximately $35.5 million in cash. The Corpus Christi, Texas, gas processing facility treats and processes off-gas from six local refineries, two of which are owned by Valero Energy Corporation, two by Koch Industries, Inc. and two by Citgo Petroleum Corporation. The Partnership and the seller negotiated a final settlement of the acquired working capital of $41.8 million, and the final payment of $5.9 million was paid to the sellers in May of 2006 and included in the final purchase price allocation, which was completed in the second quarter of 2006.

Starfish Joint Venture

On March 31, 2005, the Partnership acquired a 50% non-operating membership interest in Starfish from an affiliate of Enterprise Products Partners L.P. for $41.7 million. The Partnership financed this by borrowing $40.0 million from its credit facility during the first quarter of 2005. Starfish is a joint venture with Enbridge Offshore Pipelines LLC, which the Partnership accounts for using the equity method. Starfish owns the FERC-regulated Stingray natural gas pipeline, and the unregulated Triton natural gas gathering system and West Cameron dehydration facility. All of the assets are located in the Gulf of Mexico and southwestern Louisiana.

The following table summarizes the costs and allocations of the above acquisitions (in thousands):

	2006	2005
	Santa Fe	Javelina
Acquisition Costs:		
Cash consideration	$14,941	$396,836
Direct acquisition costs	29	2,009
Totals:	$14,970	$398,845
Allocation of acquisition costs:		
Current assets	$331	$111,679
Customer contracts	11,959	194,650
Property, plant and equipment	3,087	162,859
Inventory	11	—
Liabilities assumed	(418)	(70,343)
Totals:	$14,970	$398,845

Pro Forma Results of Operations

The following table reflects the pro forma consolidated results of operations for the year ended December 31, 2005, as though the Javelina and Starfish acquisitions had occurred on January 1, 2005. The unaudited pro forma results of operations for the Santa Fe acquisition has not been presented, as the acquisition is not considered significant. The results have been prepared for comparative purposes only and may not be indicative of future results. All earnings per share information have been updated to reflect the February 2007 unit split.

	Year ended December 31, 2005	
	As Reported	Pro Forma
	(in thousands, except per unit data)	
Revenue	$541,090	$796,954
Net income (loss)	$2,355	$(5,492)
Net income (loss)—limited partners	$242	$(7,007)
Net income (loss) per share—limited partners		
Basic	$0.01	$(0.32)
Diluted	$0.01	$(0.32)
Weighted average number of outstanding common units:		
Basic	21,790	21,790
Diluted	21,858	21,858

4. Significant Customers and Concentration of Credit Risk

For the years ended December 31, 2007, 2006 and 2005, revenues from MarkWest Hydrocarbon totaled $75.0 million, $73.6 million and $64.9 million, representing 12% of consolidated Partnership revenues. Sales to MarkWest Hydrocarbon are made primarily from the Appalachia segment. As of December 31, 2007 and 2006, the Partnership had $8.6 million and $4.7 million, respectively, of accounts receivable from MarkWest Hydrocarbon.

For the years ended December 31, 2007 and 2006, revenues from one customer totaling $191.5 million and $76.0 million, representing 31.8% and 12.1% of consolidated Partnership revenues, respectively. Sales to this customer are made primarily from the East Texas segment. As of December 31, 2007 and 2006, the Partnership had $6.4 million and $3.0 million of accounts receivable from this customer, respectively.

For the years ended December 31, 2007 and 2006, revenues from one customer totaled $88.9 million and $63.0 million, representing 14.8% and 10.0% of consolidated Partnership revenues, respectively. Sales to this customer are made primarily from the Oklahoma segment. As of December 31, 2007 and 2006, the Partnership had $9.5 million and $5.2 million of accounts receivable from this customer, respectively.

For the year ended December 31, 2005, revenues from one other customer totaled $67.0 million, representing 12.4% of consolidated Partnership revenues, respectively. Sales to this customer were made primarily from the Oklahoma segment. As of December 31, 2005, the Partnership had $5.5 million of accounts receivable from this customer.

5. Receivables and Other Current Assets

Receivables consist of the following (in thousands):

	December 31, 2007	December 31, 2006
Trade, net	$101,828	$68,692
Other	8,326	17,434
Total receivables	$110,154	$86,126

Other current assets consist of the following (in thousands):

	December 31, 2007	December 31, 2006
Margin deposits (see Note 12)	$19,300	$—
Prepaid fuel	14	1,215
Prepaid insurance	192	391
Prepaid equipment rental	401	283
Merger finance costs	857	—
Risk management premiums	—	1,009
Prepaid other	129	149
Total other current assets	$20,893	$3,047

6. Property, Plant and Equipment

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

	December 31, 2007	December 31, 2006
Gas gathering facilities	$596,627	$289,586
Gas processing plants	213,487	217,080
Fractionation and storage facilities	24,266	23,470
Natural gas pipelines	42,347	42,361
Crude oil pipelines	19,113	19,113
NGL transportation facilities	4,676	5,326
Land, building and other equipment	15,498	16,871
Construction in progress	49,220	41,942
	965,234	655,749
Less: accumulated depreciation	(141,497)	(104,863)
Total property, plant and equipment	$823,737	$550,886

The Partnership capitalizes interest on major projects during construction. For the years ended December 31, 2007 and 2006, the Partnership capitalized interest of $3.3 million and $0.9 million, respectively.

7. Intangible Assets

The Partnership's intangible assets at December 31, 2007 and 2006, are comprised of customer contracts and relationships, as follows (in thousands):

	December 31, 2007			December 31, 2006			
Description	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net	Useful Life
East Texas	$165,379	S(28,252)	$137,127	$165,379	$19,984	$145,395	20 years
Javelina	195,137	(16,903)	178,234	195,137	9,096	186,041	25 years
Oklahoma	11,959	(598)	11,361	12,630	—	12,630	20 years
Total:	$372,475	$(45,753)	$326,722	$373,146	$29,080	$344,066	

Amortization expense related to the intangible assets was $16.7 million, $16.0 million and $9.7 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Estimated future amortization expense related to the intangible assets at December 31, 2007, is as follows (in thousands):

Year ending December 31:	
2008	$16,672
2009	16,672
2010	16,672
2011	16,672
2012	16,672
Thereafter	243,362
	$326,722

8. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	December 31,	
	2007	2006
Product and operations	$14,689	$8,653
Professional services	956	1,133
Taxes (other than income tax)	4,428	3,118
Interest	13,457	13,935
Accrued property, plant and equipment	16,913	10,866
Deferred income	1,436	167
Deferred lease obligation	2,235	2,344
Phantom unit accrual	2,807	2,007
Accrued derivative settlement	1,940	—
Other	1,177	1,032
Total accrued liabilities	$60,038	$43,255

9. Asset Retirement Obligation

The following is a reconciliation of the changes in the asset retirement obligation from January 1, 2006 to December 31, 2007 (in thousands):

	Year ended December 31,	
	2007	2006
Beginning asset retirement obligation	$1,268	$1,102
Liabilities incurred	109	64
Revisions in estimated cash flows	144	—
Accretion expense	114	102
Ending asset retirement obligation	$1,635	$1,268

At December 31, 2007 and 2006, 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.

10. Impairment of Long-Lived Assets

The Partnership's policy is to evaluate whether there has been a permanent impairment in the value of long-lived assets when certain events have taken place that indicate that the remaining balance may not be recoverable. The Partnership evaluates the carrying value of its property and equipment on at least a segment level and at lower levels where cash flows for specific assets can be identified.

The analysis determined that a system located in the Other Southwest segment had future estimated cash inflows estimated to be near zero because the system was shut-in for a year, and as such the carrying amounts of the assets exceeded the estimated undiscounted cash flows. It was determined that an impairment of the system had occurred. Fair value of the long-lived assets was determined based on management's opinion that the idle assets had no economic value. Therefore, an impairment of long-lived assets of $0.4 million was recognized during the year ended December 31, 2007.

11. Debt

Debt is summarized below (in thousands):

	December 31,	
	2007	2006
Credit facility		
Revolver facility, 7.09% and 8.75% interest, respectively, due December 2010	$55,500	$30,000
Senior Notes		
Senior Notes, 6.875% interest, due November 2014	225,000	225,000
Senior Notes, 8.5% interest, net of original issue discount of $2,805 and $3,135, respectively, due July 2016	272,195	271,865
Total long-term debt	$552,695	$526,865

Partnership Credit Facility

On December 29, 2005, the Operating Company, a wholly owned subsidiary of MarkWest Energy Partners L.P., entered into the fifth amended and restated credit agreement ("Partnership Credit Facility"), which provides for a maximum lending limit of $615.0 million for a five-year term. The credit facility includes a revolving facility of $250.0 million and a $365.0 million term loan. In July 2006, using proceeds from debt and equity offerings, the Partnership permanently reduced the borrowing capacity of the term loan to $45.9 million. In October 2006 the Partnership retired the remaining $45.9 million outstanding on the term loan using a portion of the proceeds from the 2016 senior notes (see Note 16). The credit facility is guaranteed by the Partnership and all of the Partnership's subsidiaries and is collateralized by substantially all of the

Partnership's assets and those of its subsidiaries. The borrowings under the credit facility bear interest at a variable interest rate, plus basis points. The basis points vary based on the ratio of the Partnership's Consolidated Debt (as defined in the Partnership Credit Facility) to Consolidated EBITDA (as defined in the Partnership Credit Facility), ranging from 0.50% to 1.50% for Base Rate loans, and 1.50% to 2.50% for Eurodollar Rate loans. The basis points will increase by 0.50% during any period (not to exceed 270 days) where the Partnership makes an acquisition for a purchase price in excess of $50.0 million ("Acquisition Adjustment Period"). For the year ended December 31, 2007, the weighted average interest rate on the outstanding borrowing under the Partnership Credit Facility was 7.09% and had no unused letters of credit.

Under the provisions of the Partnership Credit Facility, the Partnership is subject to a number of restrictions on its business, including restrictions on its ability to grant liens on 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 (other than subordinated indebtedness); make distributions on equity investments; and declare or make, directly or indirectly, any restricted payments.

The Partnership Credit Facility also contains covenants requiring the Partnership to maintain:

- a ratio of not less than 3.00 to 1.00 of Consolidated EBITDA to consolidated interest expense for any fiscal quarter-end;
- a ratio of not more than 5.25 to 1.00 of total consolidated debt to Consolidated EBITDA for any fiscal quarter-end; and
- a ratio of not more than 3.75 to 1.00 of consolidated senior debt to Consolidated EBITDA for any fiscal quarter-end.

Both the total debt and senior debt ratios contain adjustment clauses providing for greater flexibility during any Acquisition Adjustment Period.

These covenants are used to calculate the available borrowing capacity on a quarterly basis. The Partnership incurs a commitment fee on the unused portion of the credit facility at a rate between 30.0 and 50.0 basis points based upon the ratio of Consolidated Senior Debt (as defined in the Partnership Credit Facility) to Consolidated EBITDA (as defined in the Partnership Credit Facility). The revolver portion of the facility matures on December 29, 2010. The Partnership's Credit Facility also contains provisions requiring prepayments from certain Net Cash Proceeds (as defined in the Partnership Credit Facility) received from certain triggering sales that have not been reinvested within one hundred eighty days. The Javelina Acquisition (see Note 3) was funded through the fourth amended and restated credit agreement, which provided for a maximum lending limit of $500.0 million for a term of one year and was comprised of a revolving facility of $100.0 million and a $400.0 million term loan. The fourth amended and restated credit agreement had terms similar to the new credit facility. In the fourth quarter of 2005 the Partnership completed two private placement offerings to repay a portion of the borrowed funds. The Partnership was in compliance with all covenants as of December 31, 2007.

In October 2004 the Operating Company, coincident with the issuance of the 2014 Senior Notes discussed below, entered into the third amended and restated credit agreement ("Old Credit Facility"), which provided for a maximum lending limit of $200.0 million for a term of five years. The Old Credit Facility included a revolving facility of $200.0 million. The borrowings under the Old Credit Facility carried interest at a variable rate based on one of two indices that included either (i) LIBOR plus an applicable margin, which was fixed at a rate of 2.75% for the first two quarters following the closing of the credit facility, or (ii) Base Rate (as defined for any day, a fluctuating rate per annum equal to the higher of (a) the Federal Funds Rate plus $^1/_2$ of 1% or (b) the rate of interest in effect for such day as publicly announced from time to time by the administrative agent of the debt as its "prime rate") plus an applicable margin, which margin is fixed at a rate of 2.00% for the first two quarters following the closing of the credit facility. After that period the applicable margin adjusted quarterly based on the ratio of funded debt to EBITDA (as defined in the credit agreement).

Subsequent to year end, the Partnership Credit Facility was replaced with a new debt agreement as further discussed in Note 22.

2014 Senior Notes

In October 2004 MarkWest Energy Partners, L.P. and its wholly owned subsidiary, MarkWest Energy Finance Corporation (the "Issuers"), co-issued $225.0 million in senior notes at a fixed rate of 6.875%, payable semi-annually in arrears on May 1 and November 1, and commencing on May 1, 2005 (the "2014 Senior Notes"). The 2014 Senior Notes mature on November 1, 2014. The Partnership may redeem some or all of the notes at any time on or after November 1, 2009, at certain redemption prices together with accrued and unpaid interest to the date of redemption. The Partnership may redeem all of the notes at any time prior to November 1, 2009, at a make-whole redemption price. In addition, prior to November 1, 2007, the Partnership may redeem up to 35% of the aggregate principal amount of the notes with the proceeds of certain equity offerings at a stated redemption price. The Partnership must offer to repurchase the notes at a specified price if it a) sells certain assets and does not reinvest the proceeds or repay senior indebtedness, or b) experiences specific kinds of changes in control. The 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 its Partnership Credit Facility. The proceeds from these notes were used to pay down the Partnership's outstanding debt under its credit facility. The Issuers have no assets or operations independent of this debt and their investments in guarantor subsidiaries. Each of the Partnership's existing subsidiaries, other than MarkWest Energy Finance Corporation, has guaranteed the notes jointly and severally and fully and unconditionally. The 2014 Senior Notes are senior unsecured obligations equal in right of payment with all of the Partnership's existing and future senior debt. These 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 its Partnership Credit Facility.

The indenture governing the Partnership's 2014 Senior Notes limits the activity of the Partnership and its restricted subsidiaries. Limitations include 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, 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. Subject to compliance with certain covenants, the Partnership may issue additional notes from time to time under the indenture pursuant to Rule 144A and Regulation S under the Securities Act of 1933.

The Partnership agreed to file an exchange offer registration statement or, under certain circumstances, a shelf registration statement, pursuant to a registration rights agreement relating to the 2014 Senior Notes. The Partnership failed to complete the exchange offer in the time provided for in the subscription agreements (April 26, 2005) and, as a consequence, was incurring an interest rate penalty of 0.5% annually, increasing 0.25% every 90 days thereafter up to 1%, until such time as the exchange offer was completed. The registration statement was filed on January 17, 2006, the exchange offer was completed on March 7, 2006, and the interest penalty ceased.

2016 Senior Notes

In July 2006 MarkWest Energy Partners, L.P. and its wholly owned subsidiary, MarkWest Energy Finance Corporation (the "Issuers"), co-issued $200 million in aggregate principal amount of $8^1/_2$% senior notes due 2016 (the "2016 Senior Notes") to qualified institutional buyers. The 2016 Senior Notes will mature on July 15, 2016, and interest is payable on each July 15 and January 15, commencing January 15, 2007. In October 2006 the Partnership offered $75.0 million in additional debt securities under this same indenture. The net proceeds from the private placements were approximately $191.2 million and $74.5 million, respectively, after deducting the initial purchasers' discounts and legal, accounting and other transaction expenses. The Issuers used a portion of the net proceeds from the offerings to repay the term debt under the Partnership Credit Facility. Affiliates of several of the initial purchasers, including RBC Capital Markets Corporation, J.P. Morgan Securities Inc., and Wachovia Capital Markets, LLC, are lenders under the Partnership Credit Facility. The Issuers have no assets or operations independent of this debt and their investments in guarantor subsidiaries. Each of the Partnership's existing subsidiaries, other than MarkWest Energy Finance Corporation, has guaranteed the notes jointly and severally and fully and unconditionally. The 2016 Senior Notes are senior unsecured obligations equal in right of payment with all of the Partnership's existing and future senior debt. These 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 its Partnership Credit Facility.

The indenture governing the Partnership's 2016 Senior Notes limits the activity of the Partnership and its restricted subsidiaries. Limitations under the indenture include 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, 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. Subject to compliance with certain covenants, the Partnership may issue additional notes from time to time under the indenture pursuant to Rule 144A and Regulation S under the Securities Act of 1933.

The aggregate minimum principal payments on long-term debt are as follows, as of December 31, 2007, exclusive of any prepayments related to Excess Cash Flow (in thousands):

Year ending December 31:	
2008	$—
2009	—
2010	55,500
2011	—
2012	—
Thereafter	500,000
	$555,500

12. Derivative Financial Instruments

Commodity Instruments

The Partnership's primary risk management objective is to reduce downside volatility in its cash flows arising from changes in commodity prices related to future sales of natural gas, NGLs and crude oil. Swaps and futures contracts may allow the Partnership to reduce downside volatility in its realized margins as realized losses or gains on the derivative instruments generally are offset by corresponding gains or losses in the Partnership's sales of physical product. While management largely expects realized derivative gains and losses to be offset by increases or decreases in the value of physical sales, the Partnership will experience volatility in reported earnings due to the recording of unrealized gains and losses on derivative positions that will have no offset. The Partnership's non-trading commodity derivative instruments are recorded at fair value in the Consolidated Balance Sheets and Statements of Operations. Accordingly, the volatility in any given period related to unrealized gains or losses can be significant to the overall financial results of the Partnership; however, management ultimately expects those gains and losses to be offset when they become realized. The Partnership does not have any trading derivative financial instruments.

Because of the strong correlation between NGL prices and crude oil prices and limited liquidity in the NGL financial market, the Partnership uses crude oil derivative instruments to manage NGL price risk. As a result of these transactions, the Partnership has mitigated a significant portion of its expected commodity price risk with agreements expiring at various times through the fourth quarter of 2010. The margins earned from condensate sales are directly correlated with crude oil prices. The Partnership has a committee comprised of the senior management team that oversees all of the risk management activity and continually monitors the risk management program and expects to continue to adjust its financial positions as conditions warrant.

The Partnership utilizes a combination of fixed-price forward contracts, fixed-for-floating price swaps and options available in the over-the-counter ("OTC") market, and futures contracts traded on the New York Mercantile Exchange. The Partnership enters into OTC swaps with financial institutions and other energy company counterparties. Management conducts a standard credit review on counterparties and has agreements containing collateral requirements where deemed necessary. The Partnership uses standardized agreements that allow for offset of positive and negative exposures. Some of the agreements may require a margin deposit. The margin deposits have been recorded as "Other current assets" in the accompanying Condensed Consolidated Balance Sheets (see Note 5).

The use of derivative instruments may create exposure to the risk of financial loss in certain circumstances, including instances when (i) NGLs do not trade at historical levels relative to crude oil, (ii) sales volumes are less than expected, requiring market purchases to meet commitments, or (iii) OTC counterparties fail to purchase or deliver the contracted quantities of natural gas, NGLs or crude oil or otherwise fail to perform. To the extent that the Partnership engages in derivative activities, it may be prevented from realizing the benefits of favorable price changes in the physical market; however, it may be similarly insulated against unfavorable changes in such prices.

Fair value is based on available market information for the particular derivative instrument, and incorporates the commodity, period, volume and pricing. Where published market values are not readily available, the Partnership uses a third-party service. The Partnership periodically compares the third party pricing to available broker quotes. The options are recorded at fair value on the balance sheet. The impact of the Partnership's commodity derivative instruments on financial position are summarized below (in thousands):

	December 31, 2007	December 31, 2006
Fair value of derivative instruments:		
Current asset	$99	$4,211
Noncurrent asset	82	2,759
Current liability	(21,658)	(91)
Noncurrent liability	(35,381)	(1,362)
Risk management premiums:		
Current asset	$—	$1,009
Noncurrent asset	717	717

The Partnership has recorded premium payments relating to certain derivative option contracts. The premiums allowed the Partnership to secure specific pricing on those contracts. The payment is recorded as an asset and is amortized through revenue as the puts expire or are exercised. The current and noncurrent risk management premiums have been recorded as "Other assets" and "Other long-term assets," respectively, in the accompanying Consolidated Balance Sheets.

The Partnership generally accounts for the impact of its commodity derivative instruments as a component of revenue. The Partnership also has a contract allowing it to fix a component of the price of electricity at one of its plant locations. Unrealized gains (losses) from the contract are recognized as a component of facility expenses. The impact of the Partnership's commodity derivative instruments included in "Revenue" and "Facility expenses" in the accompanying Consolidated Statements of Operations are summarized below (in thousands):

	Year ended December 31, 2007	2006	2005
Revenue:			
Realized loss	$(4,155)	$(613)	$(1,194)
Unrealized (loss) gain	(62,388)	6,245	(657)
Derivative (loss) gain	$(66,543)	$5,632	$(1,851)

	Year ended December 31, 2007	2006	2005
Facility expenses:			
Unrealized gain	$12	$—	$—

13. Incentive Compensation Plans

Total compensation expense for share-based pay arrangements was as follows (in thousands):

	Year ended December 31,		
	2007	2006	2005
MarkWest Energy Partners			
Restricted units	$2,080	$1,686	$1,076
Distribution equivalent rights	235	198	120
MarkWest Hydrocarbon			
General partner interests under Participation Plan	10,880	13,463	2,038
Subordinated units under Participation Plan	—	22	17
Total compensation expense	$13,195	$15,369	$3,251

Of the total compensation expense recognized for restricted units, $0.1 million, and $0.4 million related to the accelerated vesting of restricted units for the years ended December 31, 2006, and 2005, respectively. The accelerated vesting of restricted units occurs when specific distribution targets are achieved, as set forth in the individual grant agreements.

A Distribution Equivalent Right is a right, granted in tandem with a specific restricted 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 restricted unit is outstanding. Cash compensation expense has been recorded as either "Selling, general and administrative expenses" or "Facility expenses" in the accompanying Consolidated Statements of Operations.

Compensation expense has been recorded as "Selling, general and administrative expenses" in the accompanying Consolidated Statements of Operations. The expense not yet recognized as of December 31, 2007, related to unvested restricted units was $1.6 million, with a weighted average remaining vesting period of 1.5 years. The actual compensation expense recognized might differ for the restricted units, as they qualify as liability awards, which are affected by changes in fair value.

MarkWest Energy Partners, L.P. Long-Term Incentive Plan

The General Partner has adopted the Long Term Incentive Plan (the "LTIP") for employees and directors of the General Partner, as well as employees of its affiliates who perform services for the Partnership. The LTIP currently permits the grant of awards covering an aggregate of 1.0 million common units, comprised of 0.4 million restricted units and 0.6 million unit options. The LTIP is administered by the compensation committee of the General Partner's Board of Directors.

Restricted Units. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the Compensation Committee, cash equivalent to the value of a common unit. The restricted units vest over a service period of three years, although vesting for certain awards accelerates if specific annualized distribution goals are met.

Unit Options. The Compensation Committee has the authority to make grants of unit options under the LTIP to employees and directors containing such terms as determined by the committee. As of December 31, 2007, the Partnership had not issued any unit options.

The following is a summary of restricted units granted under the LTIP:

	Number of units	Weighted-average grant-date fair value
Unvested at January 1, 2005	59,000	$20.65
Granted	40,278	24.74
Vested	(18,200)	18.95
Forfeited	(3,350)	21.25
Unvested at December 31, 2005	77,728	23.14
Granted	81,886	24.35
Vested	(26,986)	22.25
Forfeited	(7,428)	22.75
Unvested at December 31, 2006	125,200	24.14
Granted	54,716	31.62
Vested	(40,912)	23.50
Forfeited	(13,754)	25.93
Unvested at December 31, 2007	125,250	27.42

	Year ended December 31,		
	2007	2006	2005
Weighted-average grant-date fair value of restricted units granted for the year	$1,730,054	$1,993,658	$996,423
Total fair value of restricted units vested / total intrinsic value of restricted units settled for the year	1,281,046	636,713	444,550

During the years ended December 31, 2007, 2006, and 2005, the Partnership received no proceeds (other than the contributions by the General Partner to maintain its 2% ownership interest) for issuing restricted units. None of the restricted units that vested in 2007, 2006, and 2005 were redeemed by the Partnership for cash. For the years ended December 31, 2007, 2006, and 2005, the Partnership issued 40,912, 26,986, and 17,000 common units, respectively, and an additional 500 units were acquired in the open market in 2005.

As of the Merger, the Partnership assumed the MarkWest Hydrocarbon, Inc. 2006 Stock Incentive Plan ("2006 Plan") which converted the outstanding shares of restricted stock granted under the 2006 Plan to restricted units. The converted restricted units will remain outstanding under the term of the 2006 Plan until their respective settlement dates. The 2008 Long-Term Incentive Plan ("2008 LTIP") was approved by the unitholders on February 21, 2008, which makes available 2.5 million Partnership common units for issuance in the future. Refer to Note 22 for discussions of grants made under the 2008 LTIP.

MarkWest Hydrocarbon Participation Plan

MarkWest Hydrocarbon has also entered into arrangements with certain directors and employees of the Company referred to as the Participation Plan. Under it, the Company sells interests in the General Partner under a purchase and sale agreement. There is no vesting period or maximum contractual term under the Participation Plan.

The interests in the General Partner are sold with certain put-and-call provisions. These require MarkWest Hydrocarbon to buy back, or require the individuals to sell back their interest in the general partner to MarkWest Hydrocarbon. Specifically, the employees and directors can exercise their put if (1) MarkWest Hydrocarbon or the Partnership's general partner undergoes a change of control; (2) additional membership interests are issued that, on a pro forma basis, decrease the distributions to all the then-existing members; (3) any amendment, alteration or repeal of the provisions of the general partner agreement materially and adversely affects the then-existing rights, duties, obligations or restrictions of the employees and directors; or (4) the employee or director (i) becomes totally disabled while a director, officer or employee of the general partner of MarkWest Hydrocarbon or of any of their affiliates, or (ii) dies, or (iii) retires as a director, officer or employee of the general partner of MarkWest Hydrocarbon or of any of their affiliates after reaching the age of 60 years. The employee or his estate has 120 days after the put event to exercise the put under (4) and 30 days after notice to exercise under (1) through (3). MarkWest Hydrocarbon can exercise its call option if (i) the employee or director ceases to be a director or employee of MarkWest Hydrocarbon or any of its affiliates, or (ii) if there is a change of control of

MarkWest or of the Partnership's general partner. For the call option based upon a termination of employment or directorship, MarkWest Hydrocarbon has 12 months following the termination date to exercise its call option. MarkWest Hydrocarbon has agreed to exempt the general partner interests of three present or former directors from the call option based upon a termination of employment or directorship. Additionally, pursuant to the terms of Mr. Semple's employment agreement with MarkWest Hydrocarbon, all of his general partner interest has become exempt from the call option based upon a termination of employment or directorship for reasons other than cause. For the call option based upon a change of control of MarkWest or of the Partnership's general partner, MarkWest Hydrocarbon has 30 days following the change of control to exercise its call option.

As the formula used to determine the sale and buy-back price is not based on an independent third-party valuation, coupled with the attributes of the put-and-call provisions, these transactions are considered compensatory arrangements, similar to a stock appreciation right. Compensation expense related to general partner interests is calculated as the difference in the formula value and the amount paid by those individuals. The formula value is the amount MarkWest Hydrocarbon would have to pay the employees and directors to repurchase the general partner interests, and is based on the current market value of the Partnership's common units and the current quarterly distributions paid. On October 13, 2006, the Company completed the repurchase of a 0.5% interest in the general partner.

Pursuant to the terms of the amended and restated Class B Membership Interest Contribution Agreement dated October 26, 2007, all outstanding interests in the General Partner will be exchanged for a combination of common units and cash on the date of the merger as described in Note 22. The exchange will be accounted for as a settlement of a share based payment liability under SFAS 123R and any difference between the carrying value of the Company's liability and the payment will be recorded as additional compensation expense at the time of the merger.

14. Income Tax

On July 12, 2007, the State of Michigan enacted changes in its taxation scheme. As a result, the Partnership has made the necessary adjustments to its deferred tax assets (and liabilities) in the form of a charge (or benefit) to income, as part of its income tax provisions in the third quarter of 2007. Michigan's new tax law replaces the single business tax with a two-prong tax. The two prongs comprise a tax at the rate of 0.8% of a taxpayer's modified gross receipts and a tax at the rate of 4.95% of the taxpayer's business income. Each of the above mentioned rates also includes a surcharge of 21.99% resulting in overall rates of 0.97% and 6.03%. The new law took effect on January 1, 2008 and applies to all business activity occurring after December 31, 2007. The current single business tax will remain in effect through December 31, 2007. Adopted on September 30, 2007, and effective January 1, 2008, Michigan House Bill 5104 creates a deduction from a taxpayer's pre-apportioned business income tax base equal to the total book-tax difference triggered by the enactment of the Michigan business tax that results in a net deferred tax liability. The net impact of this change was a $0.2 million charge to income in 2007.

The Texas margin tax law that was signed into law on May 18, 2006, causes the Partnership to be subject to an entity-level tax on the portion of its income that is generated in Texas beginning with the tax year ending in 2007. The Texas margin tax is imposed at a maximum effective rate of 1.0%. As of December 31, 2007 and 2006, the Partnership has recorded a deferred tax liability related to the Texas margin tax of $1.0 million and $0.8 million, respectively.

The components of the provision for income tax from continuing operations are as follows (in thousands):

	Year ended December 31,	
	2007	2006
Current income tax expense—State	$793	$—
Deferred income tax expense—State	451	769
Provision for income tax	$1,244	$769

15. 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 allocated to the Partnership was $0.9 million, for each of the years ended December 31, 2007, 2006 and 2005, respectively. The plan is discretionary, with annual contributions determined by MarkWest Hydrocarbon's Board of Directors.

16. Partners' Capital

As of December 31, 2007, partners' capital consists of 39,357,592 common limited partner units, representing a 98% partnership interest and a 2% general partner interest. MarkWest Hydrocarbon and its subsidiaries, in the aggregate, own a 14% interest in the Partnership consisting of 4,938,992 common limited partner units and a 2% general partner interest. On August 15, 2007, the Partnership converted its remaining 1.2 million subordinated units to common units. The conversion was made due to the achievement of specified financial tests defined in the amended and restated partnership agreement. At December 31, 2007, there were no subordinated units outstanding.

The Partnership Agreement defines the Partnership's ability to issue new capital, maintain capital accounts, and distribute cash, as discussed, below.

The Partnership has the ability to issue an unlimited number of units to fund immediately accretive acquisitions. An immediately accretive acquisition is one that, in the general partner's good faith determination, would have resulted in an increase to the amount of operating surplus generated by the Partnership on a per-unit basis with respect to each of the four most recently completed quarters on a pro forma basis. During 2006 and 2005, the Partnership consummated a total of three acquisitions, aggregating approximately $455.5 million, exclusive of working capital adjustments, certain of which were subsequently funded partially by equity offerings.

The Partnership Agreement 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. Per the Partnership Agreement, compensation expense under the Participation Plan allocated to the Partnership by MarkWest Hydrocarbon is allocated entirely to the general partner (see Note 2).

Distributions of Available Cash

The Partnership distributed all of its Available Cash (as defined) to unitholders of record and the general partner 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 had 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 any one or more of the next four quarters.

Subordination Period

During the subordination period (as defined), before any distributions of available cash from operating surplus was made on the subordinated units, the common unitholders had the right to receive distributions of available cash in an amount equal to the minimum quarterly distribution of $0.50 per quarter per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters.

The subordination period ends on the first day of any quarter beginning after June 30, 2009, when certain financial tests are met. Additionally, a portion of the subordinated units may convert earlier into common units on a one-for-one basis if additional financial tests or financial goals are met. The earliest possible date by which some of the subordinated units could be converted into common units was June 30, 2005. As a result of achieving those goals all subordinated units had been converted to common units as of August 15, 2007.

Distributions of Available Cash During the Subordination Period

During the subordination period, the quarterly distributions of available cash were made in the following manner:

- *First*, 98% to the common unitholders and 2% to the general partner, until each common unitholder has received a minimum quarterly distribution of $0.25 plus any arrearages from prior quarters.

- *Second,* 98% to the subordinated unitholders and 2% to the general partner, until each subordinated unitholder has received a minimum quarterly distribution of $0.25 plus any arrearages from prior quarters.

- *Third,* 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder has received a distribution of $0.275 per quarter.

- *Thereafter,* in the manner described in "Incentive Distribution Rights" below.

Distributions of Available Cash After the Subordination Period

The Partnership will make distributions of available cash for any quarter after the subordination period in the following manner:

- *First,* 98% to all unitholders, pro rata, and 2% to the general partner until the Partnership distributes for each outstanding unit an amount equal to the minimum quarterly distribution.

- *Thereafter,* in the manner described in "Incentive Distribution Rights" below.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash after the minimum quarterly distribution and the target distribution levels, as described below, have been achieved. The general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the Partnership Agreement. As discussed in Note 22, the incentive distributions rights were exchanged for Partnership Class A Units on February 21, 2008.

If, for any quarter:

- The Partnership has distributed available cash to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and

- The Partnership has distributed available cash on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, the Partnership will distribute any additional available cash for that quarter among the unitholders and the general partner in the manner described in the following paragraph.

The general partner is entitled to incentive distributions if the quarterly distribution amount exceeds the target levels specified below:

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution ..	$0.25	98%	2%
First Target Distribution................	up to $0.275	98%	2%
Second Target Distribution	above $0.275 up to $0.3125	85%	15%
Third Target Distribution	above $0.3125 up to $0.375	75%	25%
Thereafter	above $0.375	50%	50%

In each case, the amount of the target distribution set forth above is exclusive of any distributions to common unitholders to eliminate payment of any cumulative minimum quarterly distribution. The Partnership is currently distributing at a rate in excess of $0.375 per unit.

The quarterly cash distributions applicable to 2007, 2006 and 2005, were as follows:

Quarter Ended	Record Date	Payment Date	Amount Per Unit
December 31, 2007	February 7, 2008	February 14, 2008	$0.570
September 30, 2007........	November 8, 2007	November 14, 2007	$0.550
June 30, 2007..................	August 8, 2007	August 14, 2007	$0.530
March 31, 2007	May 9, 2007	May 15, 2007	$0.510
December 31, 2006	February 8, 2007	February 14, 2007	$0.500
September 30, 2006........	November 3, 2006	November 14, 2006	$0.485
June 30, 2006..................	August 7, 2006	August 14, 2006	$0.460
March 31, 2006	May 5, 2006	May 15, 2006	$0.435
December 31, 2005	February 8, 2006	February 14, 2006	$0.410
September 30, 2005........	November 8, 2005	November 14, 2005	$0.410
June 30, 2005..................	August 9, 2005	August 15, 2005	$0.400
March 31, 2005	May 10, 2005	May 16, 2005	$0.400

Private Placement—December 18, 2007

The Partnership completed a private placement of 2.9 million unregistered common units. The units were issued at a purchase price of $31.50 per unit. The sale of units raised net proceeds of approximately $91.8 million, including the general partner's contribution of $1.8 million to maintain its 2% general partner interest and after legal, accounting and other transaction expenses. The proceeds of this private placement were used primarily to fund capital expenditure requirements.

Private Placement—April 9, 2007

The Partnership completed a private placement of approximately 4.1 million unregistered common units. The units were issued at a sales price of $32.98 per unit. The registration statement for these common units was declared effective on July 11, 2007. The sale of units resulted in net proceeds of approximately $137.7 million, including the General Partner's contribution of $2.8 million to maintain its 2% interest and after legal, accounting and other transaction expenses. The net proceeds from the offering were used to fund capital expenditure requirements.

Unit Split—February 28, 2007

On February 28, 2007 the Partnership completed a two-for-one split of the Partnership's common units, whereby holders of record at the close of business on February 22, 2007 received one additional common unit for each common unit owned on that date. The unit split resulted in the issuance of 15,603,257 common units and 600,000 Subordinated units Partnership units. For all periods presented, all references to the number of units and per unit net income and distribution amounts included in this report have been adjusted to give the effect for the unit split.

Public Offering—July 6, 2006

The Partnership priced its offering of 6,000,000 common units at $19.875 per unit. In addition, on July 12, 2006, the Partnership completed the sale of an additional 600,000 common units to cover over-allotments in connection with the Common Unit Offering. The sale of units resulted in total gross proceeds of $131.2 million, and net proceeds of approximately $125.9 million, after the underwriters' commission and legal, accounting and other transaction expenses. The Partnership used the net proceeds from the offering, which includes a capital contribution from its general partner to maintain its 2% general partner interest in the Partnership, to repay a portion of the outstanding indebtedness under term debt on the Partnership Credit Facility.

Private Placement—December 28, 2005

The Partnership sold 1,149,428 common units to certain accredited investors at $21.75 per common unit, for gross proceeds of $25.0 million. $20 million of the proceeds were received in December 2005. The remaining $5 million was accrued at December 31, 2005, and received in January 2006. Offering costs of $0.1 million reduced the aggregate gross proceeds of $25.0 million to $24.9 million of net proceeds. The net proceeds of $24.9 million, and the $0.5 million contributed by the general partner to maintain its 2% interest, resulted in total net proceeds associated with the private placement of $25.4 million.

Private Placement—November 11, 2005

The Partnership sold 3,288,130 common units to certain accredited investors at $22.105 per common unit, for gross proceeds of $72.7 million. Offering costs of $0.1 million reduced the aggregate gross proceeds of $72.7 million to $72.6 million of net proceeds. The net proceeds of $72.6 million, and the $1.5 million contributed by the general partner to maintain its 2% interest, resulted in total net proceeds associated with the private placement of $74.1 million.

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 is reasonable and prudent. However, the Partnership cannot assure either 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 and the Company; 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 provision and accruals for potential losses associated with all legal actions have been made in the financial statements.

In June 2006, the Office of Pipeline Safety ("OPS") issued a Notice of Probable Violation and Proposed Civil Penalty ("NOPV") (CPF No. 2-2006-5001) to both MarkWest Hydrocarbon and Equitable Production Company. The NOPV is associated with the pipeline leak and an ensuing explosion and fire that occurred on November 8, 2004 in Ivel, Kentucky on an NGL pipeline owned by Equitable Production Company and leased and operated by a subsidiary, MarkWest Energy Appalachia, LLC. The NOPV sets forth six counts of violations of applicable regulations, and a proposed civil penalty in the aggregate amount of $1,070,000. An administrative hearing on the matter, previously set for the last week of March, 2007, was postponed to allow the administrative record to be produced and to allow OPS an opportunity to respond to a motion to dismiss one of the counts of violations, which involves $825,000 of the $1,070,000 proposed penalty. This count arises out of alleged activity in 1982 and 1987, which predates MarkWest's leasing and operation of the pipeline. MarkWest believes it has viable defenses to the remaining counts and will vigorously defend all applicable assertions of violations at the hearing.

Related to the above referenced 2004 pipeline explosion and fire incident, MarkWest Hydrocarbon and the Partnership have filed an action captioned *MarkWest Hydrocarbon, Inc., et al. v. Liberty Mutual Ins. Co., et al.* (District Court, Arapahoe County, Colorado, Case No. 05CV3953 filed August 12, 2005), as removed to the U.S. District Court for the District of Colorado, (Civil Action No. 1:05-CV-1948, on October 7, 2005) against their All-Risks Property and Business Interruption insurance carriers as a result of the insurance companies' refusal to honor their insurance coverage obligation to pay the Partnership for certain costs related to the pipeline incident. The costs include internal costs incurred for damage to, and loss of use of the pipeline, equipment and products; extra transportation costs incurred for transporting the liquids while the pipeline was out of service; reduced volumes of liquids that could be processed; and the costs of complying with the OPS Corrective Action Order (hydrostatic testing, repair/replacement and other pipeline integrity assurance measures). Following initial discovery, MarkWest was granted leave of the Court to amend its complaint to add a bad faith claim and a claim for punitive damages. The Partnership has not provided for a receivable for any of the claims in this action because of the uncertainty as to whether and how much it will ultimately recover under the policies. The costs associated with this claim have been expensed as incurred and any potential recovery from the All-Risks Property and Business Interruption insurance carriers will be recognized if and when it is received. The Defendant insurance companies and MarkWest have each filed separate summary judgment motions in the action and these motions are pending with the Court.

With regard to the Partnership's Javelina facility, MarkWest Javelina is a party with numerous other defendants to several lawsuits brought by various plaintiffs who had residences or businesses located near the Corpus Christi industrial area, an area which included the Javelina gas processing plant, and several petroleum, petrochemical and metal processing and refining operations. These suits, *Victor Huff v. ASARCO Incorporated, et al.* (Cause No. 98-01057-F, 214th Judicial Dist. Ct., County of Nueces, Texas, original petition filed in March 3, 1998); *Jason and Dianne Gutierrez, individually and as representative of the estate of Sarina Galan Gutierrez* (Cause No. 05-2470-A, 28th Judicial District, severed May 18, 2005, from the *Gonzales* case cited above); and *Esmerejilda G. Valasquez, et al. v. Occidental Chemical Corp., et al.*, Case No. A-060352-C, 128th Judicial District, Orange County, Texas, original petition filed July 10, 2006; as refiled from previously dismissed petition captioned *Jesus Villarreal v. Koch Refining Co. et al.*, Cause No. 05-01977-F, 214th Judicial Dist. Ct., County of Nueces, Texas, originally filed April 27, 2005), set forth claims for wrongful death, personal injury or property damage, harm to business operations and nuisance type claims, allegedly incurred as a result of operations and emissions from the various industrial operations in the area or from products Defendants allegedly manufactured, processed, used, or distributed. The actions have been and are being vigorously defended and; based on initial evaluation and consultations; it appears at this time that these actions should not have a material adverse impact on the Partnership's financial position or results of operations.

In the ordinary course of business, the Partnership is a party to various other legal actions. In the opinion of Management, 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 operations.

Lease Obligations

The Partnership has various non-cancelable operating lease agreements expiring at various times through fiscal year 2016. Annual rent expense under these operating leases was $9.8 million, $8.0 million and $5.9 million for the years ended December 31, 2007, 2006 and 2005, respectively. The minimum future lease payments under these operating leases as of December 31, 2007, are as follows (in thousands):

Year ending December 31,	
2008	$6,251
2009	2,521
2010	2,052
2011	1,846
2012	1,879
2013 and thereafter	6,623
	$21,172

18. Related Party Transactions

Affiliated revenues in the Consolidated Statements of Operations consist of service fees and NGL product sales. Concurrent with the closing of the IPO, the Partnership entered into several contracts with MarkWest Hydrocarbon. Specifically, the Partnership entered into:

- A gas-processing agreement in which MarkWest Hydrocarbon delivers to the Partnership for processing all natural gas it receives from third-party producers. MarkWest Hydrocarbon pays the Partnership a monthly fee based on volumes delivered.

- A transportation agreement in which MarkWest Hydrocarbon delivers most of its NGLs to the Partnership for transportation through the pipeline to the Partnership's Siloam fractionator. MarkWest Hydrocarbon pays the Partnership a monthly fee based on the number of gallons delivered to the Partnership.

- A fractionation agreement in which MarkWest Hydrocarbon delivers all of its NGLs to the Partnership for unloading, fractionation, loading and storage at the Partnership's Siloam facility. MarkWest Hydrocarbon pays the Partnership a monthly fee based on the number of gallons delivered to us for fractionation, an annual storage fee, and a monthly fee based on the number of gallons of NGLs unloaded.

- A natural gas liquids purchase agreement in which MarkWest Hydrocarbon receives and purchases, and the Partnership delivers and sells, all of the NGL products the Partnership produces pursuant to the Partnership's gas- processing agreement with a third party. Under the terms of this agreement, MarkWest Hydrocarbon pays the Partnership a purchase price equal to the proceeds it receives from the resale to third parties of the NGL products. This contract also applies to any other NGL products the Partnership acquires. The Partnership retains a percentage of the proceeds attributable to the sale of the NGL products it produces pursuant to its agreement with a third party, and remits the balance of the proceeds to this third party.

Under the Services Agreement with MarkWest Hydrocarbon, MarkWest Hydrocarbon continues to provide centralized corporate functions such as accounting, treasury, engineering, information technology, insurance and other services. The Partnership reimburses MarkWest Hydrocarbon monthly for the selling, general and administrative expenses. For the years ended December 31, 2007, 2006 and 2005, MarkWest Hydrocarbon charged approximately $20.8 million, $18.0 million and $10.9 million, respectively, for these expenses.

The Partnership also reimburses MarkWest Hydrocarbon for the salaries and employee benefits, such as 401(k) and health insurance, of plant operating personnel as well as other direct operating expenses. For the years ended December 31, 2007, 2006 and 2005, these costs totaled $26.5 million, $18.1 million and $14.6 million, respectively, and are included in facility expenses. The Partnership has no employees.

19. Segment Information

The Partnership is engaged in the gathering, processing and transmission of natural gas; the transportation, fractionation and storage of natural gas liquids and refinery off-gas; and the gathering and transportation of crude oil. The Partnership is a processor of natural gas in the northeastern and southwestern United States, processing gas from the Appalachian Basin, one of the country's oldest natural gas-producing regions, and from East Texas, Gulf Coast and Michigan. 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 operations. Accordingly, the CEO makes operating decisions, assesses financial performance and allocates resources on a segment basis. The Partnership's segments are as follows:

Segment	Related Legal Entity	Products and services
Southwest		
East Texas	MarkWest Energy East Texas Gas Company, L.L.C. MarkWest Pipeline Company, L.L.C.	Gathering, processing, pipeline, fractionation and storage
Oklahoma	MarkWest Western Oklahoma Gas Company, L.L.C. MarkWest Pioneer, L.L.C.	Gathering, processing and pipeline
Other Southwest	MarkWest Power Tex L.L.C. MarkWest Pinnacle L. L.C. MarkWest PNG Utility L. L.C. MarkWest Texas PNG Utility L. L.C. MarkWest Blackhawk L. L.C. MarkWest New Mexico L. L.C.	Gathering and pipeline
Gulf Coast		
Gulf Coast	MarkWest Javelina Company, L.L.C. MarkWest Javelina Pipeline Company, L.L.C. MarkWest Gas Services, L.L.C.	Gathering, processing and pipeline
Northeast		
Appalachia	MarkWest Energy Appalachia, L.L.C.	Processing, pipelines, fractionation and storage
Michigan	Basin Pipeline, L.L.C. West Shore Processing Company, L.L.C. Matrex, L.L.C MarkWest Michigan Pipeline Company, L.L.C.	Gathering, processing and crude oil transportation

The Partnership prepares business segment information in accordance with GAAP (see Note 2), except that certain items below the "Operating Income" line are not allocated to business segments, as management does not consider them in its evaluation of business unit performance. In addition, selling, general and administrative expenses are not allocated to individual business segments. Management evaluates business segment performance based on operating income before selling, general and administrative expenses. Revenues from MarkWest Hydrocarbon are reflected as revenue from Affiliates.

The table below presents information about operating income for the reported segments for the three years ended December 31, 2007, 2006 and 2005 (in thousands).

Year ended December 31, 2007:

	East Texas	Oklahoma	Other Southwest	Appalachia	Michigan	Gulf Coast	Total
Revenue:							
Unaffiliated parties	$206,250	$229,800	$67,411	$1,924	$11,942	$77,114	$594,441
Affiliated parties	—	—	—	74,981	—	—	74,981
Total revenue	206,250	229,800	67,411	76,905	11,942	77,114	669,422
Operating expenses:							
Purchased product costs	113,693	153,241	43,954	44,718	3,114	—	358,720
Facility expenses	16,871	20,291	6,883	14,463	6,069	10,471	75,048
Depreciation	9,607	11,104	4,493	3,410	4,668	6,619	39,901
Amortization of intangible assets	8,269	598	—	—	—	7,805	16,672
Accretion of asset retirement obligations	52	28	21	13	—	—	114
Impairments	—	—	356	—	—	—	356
Operating income (loss) before items not allocated to segments	$57,758	$44,538	$11,704	$14,301	$(1,909)	$52,219	$178,611
Capital expenditures	$32,998	$247,430	$14,795	$2,488	$158	$14,441	$312,310
Assets attributable to segments	$348,670	$390,200	$33,393	$44,222	$40,979	$474,008	$1,331,472
Investment in Starfish							58,709
Leasehold improvements(1)							1,756
Fair value of derivative instruments							897
Total Assets							$1,392,834

(1) Leasehold improvements not attributable to segments include tenant improvements for the Partnership's office lease in downtown Denver, Colorado.

Year ended December 31, 2006:

	East Texas	Oklahoma	Other Southwest	Appalachia	Michigan	Gulf Coast	Total
Revenue:							
Unaffiliated parties	$174,279	$207,510	$84,595	$2,027	$13,282	$68,950	$550,643
Affiliated parties	—	—	—	73,636	—	—	73,636
Total Revenue	174,279	207,510	84,595	75,663	13,282	68,950	624,279
Operating expenses:							
Purchased product costs	91,637	170,168	67,349	43,648	3,435	—	376,237
Facility expenses	15,683	7,883	5,638	13,997	5,721	11,190	60,112
Depreciation	7,783	3,007	4,100	3,573	5,015	6,500	29,978
Amortization of intangible assets	8,244	—	—	—	—	7,803	16,047
Accretion of asset retirement obligations	44	26	20	12	—	—	102
Operating income (loss) before items not allocated to segments	$50,888	$26,426	$7,488	$14,433	$(889)	$43,457	$141,803
Capital expenditures	$23,508	$34,114	$12,669	$2,315	$156	$2,748	$75,510
Capital expenditures not allocated to segments							1,877
Capital expenditures							$77,387
Assets attributable to segments	$331,485	$126,421	$72,068	$51,020	$46,383	$414,170	$1,041,547
Investment in Starfish							64,240
Fair value of derivative instruments							6,970
Leasehold Improvements							2,023
Total Assets							$1,114,780

Year ended December 31, 2005:

	East Texas	Oklahoma	Other Southwest	Appalachia	Michigan	Gulf Coast	Total
Revenue:							
Unaffiliated parties	$128,267	$214,043	$107,712	$1,686	$12,479	$13,832	$478,019
Affiliated parties	—	—	—	64,922	—	—	64,922
Total Revenue	128,267	214,043	107,712	66,608	12,479	13,832	542,941
Operating expenses:							
Purchased product costs	81,030	193,787	92,602	38,435	3,030	—	408,884
Facility expenses	10,463	4,927	4,990	19,360	6,080	2,152	47,972
Depreciation	4,836	2,385	3,383	3,187	4,665	1,078	19,534
Amortization of intangible assets	8,293	—	68	—	—	1,295	9,656
Accretion of asset retirement obligations	33	63	22	41	—	—	159
Operating income (loss) before selling, general and administrative expenses	$23,612	$12,881	$6,647	$5,585	$(1,296)	$9,307	$56,736
Capital expenditures	$46,088	$11,937	$7,765	$4,611	$251	$98	$70,750
Assets attributable to segments	$324,231	$75,576	$59,178	$55,436	$50,560	$441,945	$1,006,926
Investment in Starfish							39,167
Total Assets							$1,046,093

The following is a reconciliation of operating income before selling, general and administrative expenses to net income (in thousands):

	Year ended December 31,		
	2007	2006	2005
Total segment revenue	$669,422	$624,279	$542,941
Revenue derivative (loss) gain not allocated to segments	(66,543)	5,632	(1,851)
Total revenue	$602,879	$629,911	$541,090
Operating income before items not allocated to segments	$178,611	$141,803	$56,736
Revenue derivative (loss) gain not allocated to segments	(66,543)	5,632	(1,851)
Facilities expense derivative gain not allocated to segments	12	—	—
Depreciation expense not allocated to segments	(270)	(15)	—
Selling, general and administrative expenses not allocated to segments	(51,334)	(44,377)	(21,597)
(Loss) gain on disposal of property, plant and equipment not allocated to segments	(7,564)	192	24
Income from operations	52,912	103,235	33,312
Earnings (losses) from unconsolidated affiliates	5,309	5,316	(2,153)
Interest income	2,887	962	367
Interest expense	(38,946)	(40,666)	(22,469)
Amortization of deferred financing costs	(2,717)	(9,094)	(6,780)
Miscellaneous (expense) income	(1,002)	11,100	78
Income before provision for income tax	18,443	70,853	2,355
Provision for income tax	(1,244)	(769)	—
Net income	$17,199	$70,084	$2,355

20. Quarterly Results of Operations (Unaudited)

The following summarizes the Partnership's quarterly results of operations (in thousands):

	Three months ended			
	March 31	June 30	September 30	December 31
2007				
Revenue	$130,840	$158,558	$167,063	$146,418
Income (loss) from operations	11,833	16,349	33,231	(8,501)
Net income (loss)	4,756	8,275	24,161	(19,993)
Limited partner's share of net income (loss)	4,657	6,332	17,182	(23,793)
Net income (loss) per limited partner unit:				
Basic	$0.14	$0.18	$0.47	$(0.64)
Diluted	$0.14	$0.17	$0.47	$(0.64)

	Three months ended			
	March 31	June 30	September 30	December 31
2006				
Revenue	$167,766	$147,987	$176,557	$137,601
Income from operations	22,400	23,311	40,300	17,224
Net income	13,873	14,094	29,978	12,139
Limited partner's share of net income	13,045	13,276	31,176	13,430
Net income per limited partner unit:				
Basic	$0.51	$0.52	$0.82	$0.41
Diluted	$0.50	$0.51	$0.82	$0.41

21. Valuation and Qualifying Accounts

Activity in the allowance for doubtful accounts is as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Balance at beginning of period	$118	$151	$211
Charged to costs and expenses	47	118	42
Other charges(1)	(5)	(151)	(102)
Balance at end of period	$160	$118	$151

(1) Bad debts written off (net of recoveries).

22. Subsequent Events

On January 28, 2008, MarkWest Pioneer, L.L.C., a wholly owned subsidiary of the Partnership announced that it has submitted a pre-filing application with the Federal Energy Regulatory Commission ("FERC") to construct a new interstate natural gas transmission pipeline. The 30-inch pipeline will be named the Arkoma Connector Pipeline ("ACP") and will extend approximately 50 miles from an interconnect with the Partnership's gathering system in the Woodford Shale production area in southeastern Oklahoma to an interconnect with the Midcontinent Express Pipeline ("MEP") in Bennington, Oklahoma. The ACP will provide significant additional outlets for producers in the Woodford Shale as volumes continue to rapidly increase. In addition, the Partnership executed agreements with significant Woodford producers, including Newfield Exploration Company, to provide transportation capacity in excess of 500,000 Mcf/d on the ACP. The Partnership plans to spend $40.0 million in 2008 on developing the ACP, to be funded by operating cash flows and available debt.

In conjunction with the transportation agreements, the Partnership and Midcontinent Express Pipeline LLC ("MEP LLC") entered into an option agreement that provides the Partnership with a one-time right to acquire 10 percent of the equity of MEP LLC after construction is complete on the MEP and it is placed into service. MEP LLC is a 50/50 joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. The MEP, connecting Bennington, Oklahoma, and Perryville, Louisiana, will have initial capacity of 1.4 Bcf/d.

On February 11, 2008, the Partnership agreed to acquire a 20% interest in Centrahoma Operating LLC ("Centrahoma LLC") for $11.6 million, with a right to acquire an additional 20% interest under certain circumstances. Closing on March 3, 2008 is subject to conveyance of certain properties to Centrahoma LLC by the other member and the reimbursement of $0.6 million to the Partnership related to the termination of a virtual joint venture with the other member of the Centrahoma LLC. Centrahoma Operating LLC will own certain processing plants in the Arkoma basin. In addition, MarkWest will sign, at closing, agreements to dedicate certain acreage in the Woodford Shale play to the Centrahoma LLC through March 1, 2018.

On February 20, 2008, the Partnership entered into a new credit agreement ("Partnership Credit Agreement"). The Partnership Credit Agreement provides for a maximum lending limit of $575.0 million for a five-year term. The Partnership Credit Agreement includes a senior secured revolving facility of $350.0 million (that under certain circumstances can be increased to $550.0 million) and a $225.0 million term loan, both of which can be repaid at any time without penalty. The credit facility is guaranteed by the Partnership and all of the Partnership's subsidiaries, including the Company, and is collateralized by substantially all of the Partnership's assets and those of its subsidiaries. The Partnership made an intercompany loan to the Company in the amount of $225.0 million to fund, in part, the redemption of its common stock pursuant to the Merger and utilized borrowings under the $225.0 million term loan of the Partnership Credit Agreement. The Company will borrow the money from the Partnership on the same terms as the Partnership is borrowing the funds pursuant to the Partnership's credit facilities described above, except that the Company will pay interest to the Partnership at the Partnership's debt cost plus 1.0%. In addition, borrowings under the revolving facility portion of Partnership Credit Agreement were used to finance other payments under the Merger, outstanding amounts due on the Partnership Credit Facility of $67.0 million. The Partnership Credit Agreement required the payment of $10.2 million in deferred financing costs. As of February 25, 2008, the Partnership had borrowed $45.5 million under the revolving facility portion of Partnership Credit Agreement and approximately $258.5 was available to be borrowed.

The borrowings under the credit facility bear interest at a variable interest rate, plus basis points. The variable interest rate typically is based on the London Inter Bank Offering Rate ("LIBOR"); however, in certain borrowing circumstances the rate would be based on the higher of a) the Federal Funds Rate plus 0.5-1%, and b) a rate set by the Partnership Credit Facility's administrative agent, based on the U.S. prime rate. The basis points correspond to the ratio of the Partnership's Consolidated Funded Debt (as defined in the Partnership Credit Agreement) to Adjusted Consolidated EBITDA (as defined in the Partnership Credit Agreement), ranging from 0.50% to 1.25% for Base Rate loans, and 1.50% to 2.25% for LIBOR loans. The basis points will increase by 0.50% during any period (not to exceed 270 days) where the Partnership makes an acquisition for a purchase price in excess of $50.0 million. The Partnership will incur a commitment fee on the unused portion of the credit facility at a rate between 30.0 and 50.0 basis points based upon the ratio of consolidated senior debt (as defined in the Partnership Credit Agreement) to consolidated EBITDA (as defined in the Partnership Credit Facility). As of February 25, 2008, the interest note for borrowings under the Credit Facility was LIBOR plus 1.50%.

On February 21, 2008, the Partnership consummated the transactions contemplated by its plan of redemption and merger with the Company and MWEP, L.L.C., a wholly owned subsidiary of the Partnership. Under the Merger, the Company, subject to pro ration, redeemed for cash those shares of Company common stock electing to receive cash. Immediately after the redemption, the Partnership acquired the Company through a merger of MWEP, L.L.C. with and into the Company, pursuant to which all remaining shares of the Company's common stock were converted into approximately 15.4 million Partnership common units. As a result of the merger, the Company is a wholly owned subsidiary of the Partnership. In connection with the merger, the incentive distribution rights in the Partnership, the 2% economic interest in the Partnership of MarkWest Energy GP, L.L.C. (the "General Partner") and the Partnership common units owned by the Company were exchanged for Partnership Class A Units. Contemporaneously with the closing of the transactions contemplated by the Merger, the Partnership separately acquired 100% of the Class B membership interests in the General Partner that had been held by current and former management and certain directors of the Company and the General Partner. The Company paid to its stockholders approximately $240.5 million in cash in the redemption and the Partnership issued to the Company's stockholders approximately 15.5 million Partnership common units in the merger. As a result of the merger and redemption, the Company owns approximately 31% of the Partnership.

The Merger will be accounted for in accordance with SFAS 141, and related interpretations. The Merger is considered a downstream merger whereby the Company is viewed as the surviving consolidated entity for accounting purposes rather than the Partnership, which is the surviving consolidated entity for legal purposes. As such, the merger will be accounted for in the Company's consolidated financial statements as an acquisition of non-controlling interest using the purchase method of accounting. Under this accounting method, the Partnership's accounts, including goodwill, will be adjusted to proportionately step up the book value of certain assets and liabilities. The total fair value of the non-controlling interest to be acquired was the number of non-controlling interest units outstanding on the date the merger closed valued at the then current per unit market price of the Partnership common units. The cash and the Partnership units distributed to officers and directors of the General Partner for their Class B membership interests in the General Partner were recorded as settlement of the share-based payment liability.

The General Partner board approved the 2008 LTIP on October 12, 2007 and such plan was approved by the Partnership unitholders at the meeting to approve the Merger. The 2008 LTIP reserves 2.5 million common units for issuance for the purpose of attracting and retaining highly qualified officers, directors, key employees and other key individuals and to motivate them to serve the general partner and to expend maximum effort to improve the business results and earnings of the General Partner, the Partnership and their affiliates. The 2008 LTIP will be treated as an equity plan. No further awards will be made pursuant to the long-term incentive plan currently in place. The compensation committee of the general partner administers the 2008 LTIP and may award unrestricted units, restricted units, phantom units, distribution equivalent rights, performance awards or any combination of the aforementioned.

On February 21, 2008, 765,000 phantom units were granted to senior executives and other key employees under the 2008 LTIP. The phantom units vest on a time-based and performance-based schedule over a three year period. Forty percent (40%) of the total individual grant is based on continuing employment over the three-year vesting period, and sixty percent (60%) of the total individual grant is performance-based. Vesting of the performance-based awards is conditional upon the achievement of designated annual financial performance goals established by the Board of Directors, with 10% of the performance-based awards reserved for vesting at the discretion the Board of Directors. The annual financial performance goals will be based upon established targets of distributable cash flow per unit. This long-term equity incentive arrangement also contains a recapture provision. If the annual performance targets are not achieved in year one and/or year two of the vesting schedule, but the cumulative three year overall performance goal is achieved, the recapture provision allows for the vesting of a reduced percentage of the year one and/or year two performance equity awards.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of December 31, 2007, 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 the Partnership's disclosure controls and procedures as defined in Rule 13a-15(e) under the Exchange Act. Based on that evaluation, the Partnership's management, including the Chief Executive Officer and Chief Financial Officer, concluded the Partnership's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Partnership in reports that it files or submits under the Exchange Act is (a) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (b) accumulated and communicated to the Partnership's management, including the Chief Executive Officer and the Chief Financial Officer, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There have been changes in our internal controls over financial reporting that occurred during the fiscal year ended December 31, 2007, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting:

Remediation of Prior Year's Material Weaknesses in Internal Control. For the period ended December 31, 2006, as reported on form 10K/A Item 9A, a material weakness existed related to proper contract accounting for certain technical accounting issues such as accounting for derivatives and revenue recognition as of December 31, 2006. Specifically, management did not have a process in place to monitor previously existing contracts in response to specific technical accounting issues such as changes in SFAS No. *133, Accounting for Derivative Instruments and Hedging Activities,* and revenue recognition issues such as whether to record revenue gross as a principal or net as an agent.

Subsequent to December 31, 2006, management has enhanced its contract accounting review process to ensure appropriate accounting treatment for new and previously existing contracts. Management has also completed a reevaluation of all critical accounting memos that have a direct impact on contract accounting. In addition, management has enhanced existing contract accounting review checklists to ensure proper accounting analysis of significant revenue recognition and technical accounting areas. Management has assessed the design and operational effectiveness of these described control activities as part of its overall assessment of internal control over financial reporting as of December 31, 2007, and concluded that this material weakness has been remediated. See Management's Report on Internal Control Over Financial Reporting below for management's conclusion on its overall assessment.

Ongoing System Implementation. In May 2007 the Partnership began the phased implementation of an Enterprise Resource Planning ("ERP") system. Implementing an ERP system involves significant changes in business processes that management believes will provide meaningful benefits, including more standardized and efficient processes throughout the Partnership. As a result of this implementation, some internal controls over financial reporting have been changed to address the new environment associated with the implementation of this system. While the Partnership believes that this new system will strengthen its internal controls over financial reporting, there are inherent risks in implementing any new system and the Partnership will continue to evaluate and test these control changes to ensure the effectiveness of the Company's internal controls over financial reporting.

Except as described above, there were no other changes in the Partnership's internal controls over financial reporting during the year ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, the Partnership's internal control over financial reporting.

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) under the Exchange Act. The Partnership's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Partnership;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the financial statements.

Management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal controls over financial reporting as of December 31, 2007. In making this assessment, management used the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by Deloitte & Touche LLP, our independent registered public accounting firm. Deloitte & Touche LLP's report is contained herein.

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, 2007, 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, 2007, 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, 2007 of the Partnership and our report dated February 29, 2008, expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 29, 2008

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Management of MarkWest Energy Partners, L.P.

MarkWest Energy GP, L.L.C., as our general partner, manages our operations and activities on our behalf. Our general partner's board of directors will be elected by our unitholders following the redemption and merger. Our general partner owes a fiduciary duty to our unitholders, although such duty is limited under our Partnership Agreement. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, however, our general partner intends to incur indebtedness or other obligations that are non-recourse.

The members of the Audit Committee of the board of directors of our general partner for 2006 and 2007 were Keith E. Bailey, Charles K. Dempster and William P. Nicoletti. The Audit Committee reviews our external financial reporting, recommends engagement of our independent auditors and reviews procedures for internal auditing and the adequacy of our internal accounting controls. Following the redemption and merger, the Audit Committee will be increased to four members, who will be Keith E. Bailey (chairman), Donald C. Heppermann, William A. Kellstrom and William P. Nicoletti. Also following the redemption and merger, four members of the board of directors of our general partner will serve on the Compensation Committee, which oversees compensation decisions for the directors and officers of our general partner, as well as the overall compensation plans described below under the headings "Non-Competition, Non-Solicitation and Confidentiality Agreement and Severance Plan" and "Long-Term Incentive Plan," which is included herein by reference. The members of the Compensation Committees for 2006 and 2007 were Charles K. Dempster, Keith E. Bailey, and William P. Nicoletti. Following the redemption and merger, the Compensation Committee members will be Charles K. Dempster (chairman), Keith E. Bailey, William A. Kellstrom and Donald D. Wolf. Finally, as a result of the redemption and merger, our general partner's board established a Nominating and Corporate Governance Committee in accordance with the New York Stock Exchange's corporate governance rules. The Nominating and Corporate Governance Committee members are Don Heppermann (chairman), William A. Nicoletti, and Michael L. Beatty.

Directors and Executive Officers of MarkWest Energy GP, L.L.C.

The following table shows information for the directors and executive officers of MarkWest Energy GP, L.L.C., our general partner. Executive officers are appointed and directors are elected for one-year terms.

Name	Age	Position with our General Partner	Since
John M. Fox	67	Chairman of the Board of Directors	2002
Keith E. Bailey	65	Director	2005
Michael L. Beatty	60	Director	2008
Charles K. Dempster	65	Director	2002
Donald C. Heppermann	64	Director	2002
William A. Kellstrom	66	Director	2002
Anne E. Mounsey	41	Director	2008
William P. Nicoletti	62	Director	2002
Donald D. Wolf	64	Director	2008
Frank M. Semple	56	President, Chief Executive Officer and Director	2003
C. Corwin Bromley	50	Senior Vice President, General Counsel and Secretary	2004
Nancy K. Buese	38	Senior Vice President, Chief Financial Officer	2006
John C. Mollenkopf	46	Senior Vice President, Chief Operations Officer	2006
Randy S. Nickerson	46	Senior Vice President, Chief Commercial Officer	2006
Andrew L. Schroeder	49	Vice President, Finance and Treasurer	2003

Directors of MarkWest Energy GP, L.L.C.

Keith E. Bailey has served as a member of the Board of Directors of our general partner since January 2005. Mr. Bailey serves as the chairman of the Board's Audit Committee and also serves on the Board's Compensation Committee. Mr. Bailey was formerly the Chairman, President and Chief Executive Officer of The Williams Companies, Inc. ("Williams"). Commencing in 1973, Mr. Bailey served in various capacities with Williams and its subsidiaries, including President and Chairman of Williams Pipe Line, Chairman of WilTel Communications, President of Williams Natural Gas, and Executive Vice President and Chief Financial Officer of Williams. Also, Mr. Bailey served on the Williams board of directors from 1988 until his retirement in 2002, including eight years as Chairman. He currently serves on the boards of directors of Apco Argentina Inc., Associated Electric & Gas Insurance Services Limited (AEGIS) and Integrys Energy Group, Inc. Mr. Bailey holds a bachelor's degree in mechanical engineering from the Missouri School of Mines and Metallurgy.

Michael L. Beatty was elected to the Board of Directors of our general partner in February 2008 and serves on the Board's Nominating and Corporate Governance Committee, having previously served as a member of the board of directors of MarkWest Hydrocarbon, Inc. since June 2005. Mr. Beatty is currently Chairman of the law firm of Beatty & Wozniak, P.C. headquartered in Denver, Colorado, with a practice focused exclusively on energy, including oil and gas exploration, regulatory affairs, public lands, litigation and title. A Harvard Law School graduate, Mr. Beatty began his career in the energy industry as in-house counsel for Colorado Interstate Gas Company, and ultimately became Executive Vice President, General Counsel and a Director of The Coastal Corporation. He served as Chief of Staff to Colorado Governor Roy Romer from 1993 to 1995. Mr. Beatty also currently serves on the board of directors of Denbury Resources Inc.

Charles K. Dempster has served as a member of the Board of Directors of our general partner since December 2002. Mr. Dempster serves as the chairman of the Board's Compensation Committee. Mr. Dempster has more than 30 years of experience in the natural gas and power industry. He held various management and executive positions with Enron Corporation and its predecessors between 1969 and 1986, focusing on natural gas supply, transmission and distribution. From 1986 through 1992, Mr. Dempster served as President of Reliance Pipeline Company and Executive Vice President of Nicor Oil and Gas Corporation, oil and natural gas midstream and exploration subsidiaries of Nicor Inc. in Chicago. In 1993, he was appointed President of Aquila Energy Corporation, a wholly owned midstream, pipeline and energy-trading subsidiary of Utilicorp, Inc. Mr. Dempster retired in 2000 as Chairman and Chief Executive Officer of Aquila Energy Company. Mr. Dempster holds a bachelor's degree in civil engineering from the University of Houston and attended graduate business school at the University of Nebraska.

John M. Fox has served as Chairman of the Board of Directors of our general partner since its inception in May of 2002, and in the same capacity for MarkWest Hydrocarbon since its inception in April 1988. Mr. Fox also served as President and Chief Executive Officer of our general partner and of MarkWest Hydrocarbon from their respective inception until his retirement as President on November 1, 2003 and his resignation as Chief Executive Officer effective December 31, 2003. Mr. Fox was a founder of Western Gas Resources, Inc. and was its Executive Vice President and Chief Operating Officer from 1972 to 1986. Mr. Fox is the father of Anne E. Mounsey, a member of the Board of Directors.

Donald C. Heppermann has served as a member of the Board of Directors of our general partner since its inception in May 2002 and of the MarkWest Hydrocarbon's board of directors since November 2002, and serves as chairman of the Board's Nominating and Corporate Governance Committee and serves on the Audit Committee and the Pricing Committee. Mr. Heppermann served as Executive Vice President, Chief Financial Officer and Secretary of our general partner and of MarkWest Hydrocarbon, Inc. since October 2003 until his retirement in March 2004. Mr. Heppermann joined our general partner and MarkWest Hydrocarbon in November 2002 as Senior Vice President and Chief Financial Officer, and served as Senior Executive Vice President beginning in January 2003. Prior to joining MarkWest, Mr. Heppermann was a private investor and a career executive in the energy industry with responsibilities in operations, finance, business development and strategic planning. From 1990 to 1997, Mr. Heppermann served as President and Chief Operating Officer for InterCoast Energy Company, an unregulated subsidiary of Mid American Energy Company. From 1987 to 1990, Mr. Heppermann was employed by Pinnacle West Capital Corporation, the holding company for Arizona Public Service Company, where he was Vice President of Finance. From 1965 to 1987, Enron Corporation and its predecessors employed Mr. Heppermann in a variety of positions, including Executive Vice President, Gas Pipeline Group.

William A. Kellstrom has served as a member of the Board of Directors of our general partner since its inception in May 2002 and of MarkWest Hydrocarbon's board of directors since May 2000. Mr. Kellstrom serves on the general partner Board's Audit Committee and also serves on the Board's Compensation Committee. Mr. Kellstrom has held a variety of managerial positions in the natural gas industry since 1968. They include distribution, pipelines and marketing. He held various management and executive positions with Enron Corporation, including Executive Vice President, Pipeline Marketing and Senior Vice President, Interstate Pipelines. In 1989, he created and was President of Tenaska Marketing Ventures, a gas marketing company for the Tenaska Power Group. From 1992 until 1997 he was with NorAm Energy Corporation (since merged with Reliant Energy, Incorporated) where he was President of the Energy Marketing Company and Senior Vice President, Corporate Development. Mr. Kellstrom retired in 1997 and is periodically engaged as a consultant to energy companies.

Anne E. Mounsey was elected to the Board of Directors of our general partner in February 2008. Ms. Mounsey previously served as a member of the board of directors of MarkWest Hydrocarbon, Inc. since October 2004. From 1991 to 2003, Ms. Mounsey held various positions with MarkWest Energy and MarkWest Hydrocarbon, her most recent as Manager of Marketing and Business Development. Ms. Mounsey is the daughter of John M. Fox, our general partner's Chairman of the Board of Directors.

William P. Nicoletti has served as a member of the Board of Directors of our general partner since its inception in May 2002. Mr. Nicoletti serves on the Board's Audit Committee and also serves on the Board's Nominating and Corporate Governance Committee. Mr. Nicoletti is Managing Director of Nicoletti & Company Inc., a private banking firm formed in 1991. Previously, he was a Managing Director and head of Energy Investment Banking for PaineWebber Incorporated and E.F Hutton & Company Inc. Mr. Nicoletti is a director and Chairman of the Audit Committee of Kestrel Heat LLC, the general partner of Star Gas Partners, L.P. Mr. Nicoletti is a graduate of Seton Hall University and received an MBA from Columbia University Graduate School of Business.

Frank M. Semple was appointed as President of both our general partner and MarkWest Hydrocarbon, Inc. on November 1, 2003. Mr. Semple also became Chief Executive Officer of both MarkWest entities on January 1, 2004. Mr. Semple is a member of the Board of Directors of our general partner and of MarkWest Hydrocarbon. Prior to his service with MarkWest, Mr. Semple served in various capacities, most recently as Chief Operating Officer of WilTel Communications, formerly Williams Communications Group, Inc. ("WCG") from 1997 to 2003. Prior to his tenure at WilTel Communications, he was the Senior Vice President/General Manager of Williams Natural Gas from 1995 to 1997, Vice President of Marketing and Vice President of Operations and Engineering for Northwest Pipeline, and Director of Product Movements and Division Manager for Williams Pipeline during his 22-year career with The Williams Companies. During his tenure at Williams Communications, he also served on the board of directors for PowerTel Communications and the Competitive Telecommunications Association (Comptel). Mr. Semple holds a Mechanical Engineering degree from the United States Naval Academy and is a professional engineer registered in the state of Kansas.

Donald D. Wolf was elected to the Board of Directors of our general partner in February 2008 and serves on the Board's Compensation Committee. Mr. Wolf previously served as a member of the board of directors of MarkWest Hydrocarbon, Inc. since June 1999. In September 2004, Mr. Wolf joined Aspect Energy as President and Chief Executive Officer. He is also Chief Executive Officer of Quantum Resources, LLC. Mr. Wolf served as Chairman, Chief Executive Officer and Director of Westport Resources Corporation from July 1996 until Westport's merger with Kerr McKee Corporation in 2004. Mr. Wolf has a diversified 40-year career in the oil and natural gas industry.

Executive Officers of MarkWest Energy GP, L.L.C.

C. Corwin Bromley, Senior Vice President, General Counsel and Secretary, was appointed as General Counsel of our general partner in September 2004. Prior to joining MarkWest, Mr. Bromley served as Assistant General Counsel at Foundation Coal Holdings, Inc. f/k/a RAG American Coal Holding, Inc. from 1999 through 2004, and as General-Managing Attorney and Sr. Environmental Attorney at Cyprus Amax Minerals Company from 1989 to 1999. Prior to that, Mr. Bromley was in private practice with the law firm Popham, Haik, Schnobrich & Kaufman from 1984 through 1989. Preceding his legal career, Mr. Bromley worked as a structural/design engineer involved in several domestic and international LNG and energy projects with the firms CBI, Inc. and Chicago Bridge & Iron Company. Mr. Bromley received his J.D. degree from the University of Denver and his bachelor's degree in Civil Engineering from the University of Wyoming.

Nancy K. Buese, Senior Vice President, Chief Financial Officer, was appointed Chief Financial Officer of our general partner in October 2006. Prior to her appointment as CFO, Ms. Buese served as Chief Accounting Officer of MarkWest since November 2005. Prior to joining MarkWest, Ms. Buese was the Chief Financial Officer for Experimental and Applied Sciences ("EAS") in Golden, Colorado. EAS is a wholly owned subsidiary of Abbott Laboratories. Prior to her employment at EAS, Ms. Buese was a Vice President with TransMontaigne Inc. in Denver, Colorado. Preceding this appointment, Ms. Buese was a Partner with Ernst & Young LLP, having spent time in the firm's Denver, London, New York and Washington, D.C. offices.

John C. Mollenkopf, Senior Vice President, Chief Operations Officer, was appointed as Chief Operations Officer of our general partner in October 2006. Prior to his appointment as COO, Mr. Mollenkopf served as Senior Vice President, Southwest Business Unit, since January 2004 and as Vice President, Business Development since January 2003. Prior to these positions,, he served as Vice President, Michigan Business Unit, of our general partner since its inception in May 2002 and in the same capacity with MarkWest Hydrocarbon since December 2001. Prior to that, Mr. Mollenkopf was General Manager of the Michigan Business Unit of MarkWest Hydrocarbon since 1997. He joined MarkWest Hydrocarbon in 1996 as Manager, New Projects. From 1983 to 1996, Mr. Mollenkopf worked for ARCO Oil and Gas Company, holding various positions in process and project engineering, as well as operations supervision.

Randy S. Nickerson, Senior Vice President, Chief Commercial Officer, was appointed as Chief Commercial Officer of our general partner in October 2006. Prior to his appointment as CCO, Mr. Nickerson served as Senior Vice President, Corporate Development of MarkWest since January 2003. Prior to these positions, Mr. Nickerson served as Senior Vice President of our general partner since its inception in May 2002 and served in the same capacity with MarkWest Hydrocarbon since December 2001. Prior to that, Mr. Nickerson served as MarkWest Hydrocarbon's Vice President and the General Manager of the Appalachia Business Unit since June 1997. Mr. Nickerson joined MarkWest Hydrocarbon in July 1995 as Manager, New Projects and served as General Manager of the Michigan Business Unit from June 1996 until June 1997. From 1990 to 1995, Mr. Nickerson was a Senior Project Manager and Regional Engineering Manager for Western Gas Resources, Inc. From 1984 to 1990, Mr. Nickerson worked for Chevron USA and Meridian Oil Inc. in various process and project engineering positions.

Andrew L. Schroeder, Vice President Finance, Treasurer and Assistant Secretary, was appointed as Vice President and Treasurer of our general partner in February 2003. Prior to his appointment, he was Director of Finance/Business Development at Crestone Energy Ventures from 2001 through 2002. Prior to that, Mr. Schroeder worked at Xcel Energy for two years as Director of Corporate Financial Analysis. Prior to that, he spent seven years working with various energy companies. He began his career with Touche, Ross & Co. and spent eight years in public accounting. Mr. Schroeder is a Certified Public Accountant licensed in the state of Colorado.

Audit Committee Financial Expert

Each of the individuals serving on our Audit Committee satisfies the standards for independence of the AMEX and the SEC as they relate to audit committees. Our board of directors believes each of the members of the Audit Committee is financially literate. In addition, our board of directors has determined that Mr. Bailey is financially sophisticated and qualifies as an "audit committee financial expert" within the meaning of the regulations of the SEC.

Audit Committee Pre-Approval Policy

The Audit Committee pre-approves all audit and permissible non-audit services provided by the independent registered public accounting firm on a case-by-case basis. These services may include audit services, audit- related services, tax services and other services. Our Chief Financial Officer is responsible for presenting the Audit Committee with an overview of all proposed audit, audit-related, tax or other non-audit services to be performed by the independent registered public accounting firm. The presentation must be in sufficient detail to define clearly the services to be performed. The Audit Committee does not delegate its responsibilities to pre-approve services performed by the independent registered public accounting firm to management or to an individual member of the Audit Committee. The Audit Committee may, however, from time to time delegate its authority to the Audit Committee Chairman, who reports on the independent registered public accounting firm services approved by the Chairman at the next Audit Committee meeting.

Code of Conduct and Ethics

We have adopted a Code of Conduct and Ethics that complies with SEC standards, applicable to the persons serving as our directors, officers (including without limitation, our CEO, CFO and Principal Operations Officers) and employees. This includes the prompt disclosure to the SEC of a Current Report on Form 8-K of any waiver of the code for executive officers or directors approved by the board of directors. A copy of our Code of Business Conduct and Ethics is available free of charge in print to any unitholder who sends a request to the office of the Secretary of MarkWest Energy Partners, L.P. at 1515 Arapahoe Street, Suite 700, Denver, Colorado 80202. The Code of Conduct and Ethics is also posted on our website, *www.markwest.com*.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires our general partner's directors, executive officers, and persons who own more than 10% of any class of our equity securities registered under Section 12 of the Exchange Act, to file with the SEC initial reports of ownership and reports of changes in ownership in such securities. SEC regulations also require directors, executive officers and greater than 10% unitholders to furnish us with copies of all Section 16(a) reports they file.

To our knowledge, based solely on review of the copies of such reports furnished to us and written representations that no other reports were required, we believe our directors, executive officers and greater than 10% unitholders complied with all Section 16(a) filing requirements during the year ended December 31, 2007. We are not aware of any failures to file a Section 16(a) form with the SEC, or any transaction that was required to be reported, but that was not reported on a timely basis.

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 2008 Annual Meeting of Unitholders expected to be filed no later than April 29, 2008.

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 2008 Annual Meeting of Unitholders expected to be filed no later than April 29, 2008.

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 2008 Annual Meeting of Unitholders expected to be filed no later than April 29, 2008.

ITEM 14. Principal Accountant Fees and Services

Information required to be set forth in Item 14. Principal Accountant Fees and Expenses, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2008 Annual Meeting of Unitholders expected to be filed no later than April 29, 2008.

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

Schedule A—Significant Subsidiary Financial Statements—Starfish Pipeline Company, LLC

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

Schedule A—Significant Subsidiary Financial Statements—Starfish Pipeline Company, LLC

Starfish Pipeline Company, LLC

Consolidated Financial Statements
December 31, 2007 and 2006

Starfish Pipeline Company, LLC

Index

December 31, 2007 and 2006

Report of Independent Auditors

To the Board of Directors and Members of
Starfish Pipeline Company, LLC

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of members' capital and cash flows present fairly, in all material respects, the financial position of Starfish Pipeline Company, LLC and its subsidiaries (the "Company") at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the financial statements, the Company has significant transactions and relationships with affiliated entities.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 22, 2008

Starfish Pipeline Company, LLC

Consolidated Balance Sheets

December 31, 2007 and 2006

(in thousands of dollars)	2007	2006
Assets		
Current assets		
Cash and cash equivalents	$1,504	$2,846
Transportation receivables (Note 2)	3,920	7,416
Accrued other receivables (Note 4)	343	1,347
Other receivables from related parties	22	251
Gas imbalance and gas imbalance net under recoveries (Note 2)	491	1,511
Other assets	418	363
Total current assets	6,698	13,734
Pipelines, plant and equipment, net (Note 5)	127,019	133,443
Total assets	$133,717	$147,177
Liabilities and Members' Capital		
Current liabilities		
Accounts payable and accrued liabilities	$2,257	$2,625
Other payables to related parties	370	3,045
Gas imbalances (Note 2)	—	322
Current obligation under capital lease	622	578
Total current liabilities	3,249	6,570
Obligation under capital lease, less current portion	5,216	5,883
Asset retirement obligation (Note 7)	5,651	5,936
Regulatory liability (Note 7)	9,722	9,349
Total liabilities	23,838	27,738
Members' capital	109,879	119,439
Total liabilities and members' capital	$133,717	$147,177

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

Starfish Pipeline Company, LLC

Consolidated Statements of Income

Years Ended December 31, 2007, 2006 and 2005

(in thousands of dollars)	2007	2006	2005
Operating revenues			
Transportation	$27,081	$28,736	$16,739
Dehydration and other	5,532	3,342	2,604
Total revenues	32,613	32,078	19,343
Operating expenses			
Operating and maintenance	9,640	12,856	11,563
Administrative and general	1,724	1,922	1,821
Depreciation and amortization	8,946	7,786	6,371
Accretion and regulatory expense	344	324	316
Total operating expenses	20,654	22,888	20,071
Net operating income (loss)	11,959	9,190	(728)
Other income (expense)			
Interest expense	(453)	(504)	(536)
Interest income	183	269	42
Other income	429	546	354
Total other income (expenses)	159	311	(140)
Net income (loss)	$12,118	$9,501	$(868)

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

Starfish Pipeline Company, LLC

Consolidated Statements of Members' Capital

Years Ended December 31, 2007, 2006 and 2005

(In thousands of dollars)	MarkWest (Note1)	Enbridge (Note 1)	Total
Balances at December 31, 2004	$36,819	$36,819	$73,638
Contributions	1,486	1,486	2,972
Distributions	(2,653)	(2,654)	(5,307)
Net income	(434)	(434)	(868)
Balances at December 31, 2005	35,218	35,217	70,435
Contributions	19,751	19,752	39,503
Net income	4,751	4,750	9,501
Balances at December 31, 2006	59,720	59,719	119,439
Distributions	(10,839)	(10,839)	(21,678)
Net income	6,059	6,059	12,118
Balances at December 31, 2007	$54,940	$54,939	$109,879

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

Starfish Pipeline Company, LLC

Consolidated Statements of Cash Flows

Years Ended December 31, 2007, 2006 and 2005

(in thousands of dollars)	2007	2006	2005
Cash flows from operating activities			
Net income	$12,118	$9,501	$(868)
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	8,946	7,786	6,371
Accretion and regulatory expense	344	324	316
Provision for bad debts	—	(1,422)	1,422
Changes in working capital			
Transportation receivables	3,496	473	(3,520)
Other receivables from related parties	229	1,235	2
Gas imbalance net under recoveries	1,020	2,717	(3,403)
Accrued other receivable and other assets	703	(1,440)	(8)
Accounts payable and accrued liabilities	(1,528)	(2,708)	4,002
Gas imbalances	(322)	(6,002)	3,899
Other payables to related parties	(2,675)	2,623	(222)
Net cash provided by operating activities	22,331	13,087	7,991
Cash flows from investing activities			
Capital expenditures	(1,375)	(27,993)	(2,962)
Acquisition of assets	—	(22,747)	—
Net cash used in investing activities	(1,375)	(50,740)	(2,962)
Cash flows from financing activities			
Contribution from members	—	39,503	1,486
Distribution to members	(21,678)	—	(5,307)
Capital lease payments	(620)	(578)	(538)
Net cash (used in) provided by financing activities	(22,298)	38,925	(4,359)
(Decrease) increase in cash and cash equivalents	(1,342)	1,272	670
Cash and cash equivalents			
Beginning of year	2,846	1,574	904
End of year	$1,504	$2,846	$1,574

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

Starfish Pipeline Company, LLC

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

1. Organization and Business

Starfish Pipeline Company, LLC ("Starfish" or the "Company") was formed on December 8, 2000, under the provisions of the Delaware Limited Liability Company Act. Starfish was owned 50% each by Enterprise Products Operating, LP ("Enterprise") and Shell Gas Transmission, LLC ("Shell"), an affiliate of Shell Oil Company ("SOC"). In January 2001, Starfish acquired 100% of Stingray Pipeline Company, LLC ("Stingray"), West Cameron Dehydration, LLC ("West Cameron") and Triton Gathering, LLC ("Triton", previously East Breaks Gathering Company, LLC) from Deepwater Holdings, LLC, an affiliate of the El Paso Corporation. The purchase price was $50,200,000, which was allocated based on the fair value of the net assets acquired. Since the estimated fair value of the net assets was in excess of the purchase price, no goodwill was recorded. On December 31, 2004, SOC sold its interest in Shell to Enbridge Holdings (Offshore) L.L.C. ("Enbridge"), an affiliate of Enbridge (U.S.) Inc. Therefore, as of December 31, 2004, SOC was no longer an affiliate. Subsequent to the sale, Shell was renamed Enbridge Offshore (Gas Transmission) L.L.C. On March 31, 2005, with an effective date of January 1, 2005, Enterprise sold its interest in Starfish to MarkWest Energy Partners L.P. ("MarkWest"). Therefore, as of January 1, 2005, Enterprise was no longer an affiliate.

Stingray operates a regulated natural gas pipeline system (the "Stingray System") engaged in the transmission of natural gas in the Louisiana and Texas offshore areas. The Stingray System consists of (i) 361 miles of 6 to 36-inch diameter pipeline that transports natural gas from the High Island Offshore System, or HIOS, West Cameron, East Cameron, Garden Banks and Vermilion lease areas in the Gulf of Mexico to onshore transmission systems in Louisiana, (ii) 43 miles of 16 to 20-inch diameter pipeline connecting platforms and leases in the Garden Banks Block 191 and 72 areas to the Stingray System, and (iii) 13 miles of 16-inch diameter pipeline connecting the GulfTerra Energy Partners L.P., formerly known as El Paso Energy Partners L.P., platform at East Cameron Block 373 to the Stingray System at East Cameron Block 338.

West Cameron operates an unregulated natural gas dehydration facility that provides interruptible dehydration service to offshore platform operators connected to the Stingray System. The facility is located at Stingray station 701 in Holly Beach, Louisiana.

Triton is an unregulated gathering system that includes 18 laterals, which are connected to the Stingray System, and located in the Garden Banks, East Cameron, Vermilion, and West Cameron areas of the Gulf of Mexico. This includes the Gunnison lateral completed in December 2003 and the West Cameron 62 Lateral purchased from El Paso in May 2006.

Starfish has no employees and receives all administrative and operating support through contractual arrangements with affiliated companies. These services and agreements are outlined in Note 3, Related Party Transactions.

Agreements between the member companies address the allocation of income and capital contributions and distributions amongst the respective members' capital accounts.

The terms of the agreements include, but are not limited to, the following:

- No member is required to make a capital contribution unless such member votes to approve the capital contribution;
- If a member does not contribute by the time required, other non-defaulting members may elect to participate in its share of such advance in proportion to its membership interest;
- Starfish is required to distribute all available cash, as defined by the members, within thirty days of the end of the calendar month;
- Starfish is not required to distribute any amounts that would cause it to materially default under any debt agreement or instrument.

2. Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries. All intercompany transactions and balances have been eliminated in consolidation.

Use of Estimates and Significant Risks

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the related reported amounts of revenue and expenses during the reporting period. Such estimates and assumptions include those made in areas of FERC regulations, fair value of financial instruments, future cash flows associated with assets, useful lives for depreciation and potential environmental liabilities. Actual results could differ from those estimates. Management believes that the estimates are reasonable.

Development and production of natural gas in the service area of the pipeline and dehydration facilities are subject to, among other factors, prices for natural gas and federal and state energy policy, none of which are within Starfish's control.

Regulation

The Stingray System is an interstate pipeline subject to regulation by the Federal Energy Regulatory Commission ("FERC"). Stingray has accounting policies that conform to generally accepted accounting principles in the United States of America, as applied to regulated enterprises and are in accordance with the accounting requirements and ratemaking practices of the FERC.

Stingray follows the regulatory accounting principles prescribed under Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation.* If Stingray discontinued the application of SFAS No. 71, due to an increased level of competition and discounting in its market area, adjustments and reversals of regulatory assets and liabilities would be necessary.

Cash and Cash Equivalents

All highly liquid investments with maturity of three months or less when purchased are considered to be cash equivalents.

Allowance for Doubtful Accounts

Allowances have been established for losses on accounts, which may become uncollectible. Collectibility is reviewed regularly and the allowance is adjusted as necessary, primarily under the specific identification method. The allowance was $0 at December 31, 2007 and 2006, respectively.

The Company recognized provisions for bad debts of $1,421,567 in 2005 relating to imbalance disputes with shippers which were resolved in 2006.

Pipelines, Plant and Equipment

Pipelines, plant and equipment consist primarily of natural gas pipeline assets and related facilities that are recorded at cost. The regulated portion of the pipeline assets includes an Allowance for Funds Used During Construction ("AFUDC"). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by FERC. The pipeline and related facilities are depreciated on the straight-line method over 100 years. The dehydration facility is depreciated based on a useful life of 40 years. The laterals are depreciated based on a useful life of 10 years. Routine maintenance and repair costs are expensed as incurred while additions, improvements and replacements are capitalized.

Leased property and equipment are capitalized, as appropriate, and the present value of the related lease payments is recorded as a liability. Amortization of capitalized lease assets is computed on a straight-line method over the term of the lease and recorded as a component of depreciation expense. Improvements to leased properties are amortized over their useful lives or the lease period, whichever is shorter.

Starfish records depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, upon the disposition of property, plant and equipment, the cost less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, Starfish will recognize a gain or loss in the Consolidated Statements of Income for the difference between the cash received and the net book value of the assets sold.

Impairment of Long Lived Assets

Starfish evaluates its assets for impairment when events or circumstances indicate that the carrying values may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which Starfish intends to use a long-lived asset and adverse changes in the legal or business environment, such as adverse actions by regulators. When an event occurs, Starfish evaluates the recoverability of its carrying value based on its long-lived assets' ability to generate future cash flows on an undiscounted basis. If impairment is indicated Starfish will adjust the carrying value of assets downward.

Asset Retirement Obligations

Effective January 1, 2003, Starfish adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143, issued in June 2001, requires the recording of liabilities equal to the fair value of asset retirement obligations and corresponding additional asset costs. The obligations included are those for which there is a legal obligation as a result of existing or enacted law, statute or contract. Over time, the liability would be accreted to its present value, and the capitalized cost would be depreciated over the useful life of the related asset. Upon settlement of the liability, an entity would either settle the obligation for its recorded amount or recognize a gain or loss. Starfish's assets are under the jurisdiction of the Department of Transportation and the Minerals Management Service ("MMS"). The MMS requires the ultimate abandonment of offshore facilities when they are no longer in use or when suspension for future utilization cannot be justified. Stingray and Triton recorded asset retirement obligations for several of their laterals during FAS 143 implementation in 2003. Starfish did not recognize any asset retirement obligations for its remaining assets because these were determined to be part of the main trunk-line system or laterals with long term usage potential, and due to current reserve estimates and expanding production in the deepwater of the Gulf of Mexico, the date of abandonment could not be reasonably estimated. FIN 47 provides specific guidance regarding when an asset retirement obligation is reasonably estimable including when sufficient information is available to apply an expected present value technique. The Company's implementation of FIN 47 did not have a material impact effect on these financial statements.

Costs related to the retirement of the Stingray System are provided for in the rates charged to shippers, as allowed by the FERC. The amounts charged to shippers for the costs related to the retirement of the Stingray System differ from the period costs recognized in accordance with SFAS No. 143, and therefore, result in a difference in the timing of recognition of period costs for financial reporting and rate-making purposes. The Company recognizes a regulatory asset or liability for differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting and rate-making purposes.

Income Taxes

Starfish is treated as a tax partnership under the provisions of the Internal Revenue Code. Accordingly, the accompanying financial statements do not reflect a provision for income taxes since Starfish's results of operations and related credits and deductions will be passed through to and taken into account by its members in computing their respective tax liabilities.

Revenue Recognition

Revenue from pipeline transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline system. Revenue from dehydration services is recognized at the time the service is performed.

Gas Imbalances and Gas Imbalance Over (Under) Recoveries

In the course of providing transportation services to customers, Stingray may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. These transactions result in imbalances (gains and losses), which are settled in-kind each month through a fuel gas and unaccounted-for gas tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure included in Stingray's tariff. Gas imbalances represent natural gas volumes owed to or due from Stingray's customers. Gas imbalances and gas imbalance over (under) recoveries are valued at an average monthly index price, which was $6.9560 per dekatherm ("Dth") for the month of December 2007 and $6.6100 per Dth for the month of December 2006.

Stingray's FERC Gas Tariff, Third Revised Volume No. 1, Section 11.5, states that subsequent to the end of the twelve month billing period ending November 30 of each year, Stingray shall compare the revenues and costs under the cash-out procedures and shall refund, within 60 days, the gas imbalance net over recoveries to firm and interruptible transportation customers on a pro-rata basis in accordance with the transportation revenues Stingray received during that billing period. If the revenues received are less than the costs incurred, then Stingray shall carry forward the gas imbalance net under recoveries and may offset such net under recoveries against any future net over recoveries that may occur.

Environmental Costs

Starfish records environmental liabilities at their undiscounted amounts when environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations, and include estimates of associated legal costs. As of December 31, 2007 and 2006, Starfish had no liabilities recognized for environmental costs.

Fair Value of Financial Instruments

The reported amounts of financial instruments such as cash and cash equivalents, receivables, and current liabilities approximate fair value because of their short maturities.

Reclassifications

Certain reclassifications have been made in the prior year consolidated financial statements to conform to the 2007 financial statement presentation. These reclassifications have no impact on net income.

3. Related Party Transactions

Starfish has no employees. Operating, maintenance and general and administrative services are provided to Starfish under service agreements with an Enbridge affiliate in 2007, 2006, and 2005. Substantially all operating and administrative expenses were incurred through services provided under these agreements. At December 31, 2007 and 2006, respectively, Starfish had affiliate payables of $369,507 and $3,044,796, and affiliates receivable of $22,360 and $251,378 relating to these agreements.

4. Accrued Other Receivables

Stingray operates an on-shore separation facility and charges the owners a fee for normal operations and any direct cost relating to repairs and maintenance of the facility. Upon request, Stingray also performs offshore repairs and maintenance services and charges the owners for those services. Included in accrued other receivables is $343,285 and $1,288,531 related to these activities in 2007 and 2006, respectively.

5. Pipelines, Plant and Equipment

Pipelines, plant and equipment at December 31, 2007 and 2006, is comprised of the following:

(in thousands of dollars)	2007	2006
Regulated pipelines and equipment	$66,967	$47,585
Regulated pipeline under capital lease	9,778	9,778
Unregulated pipelines and equipment	66,312	66,312
Dehydration facilities	4,349	4,349
Construction in progress	16,004	32,865
Asset retirement cost (regulated pipelines)	1,398	2,027
	164,808	162,916
Accumulated depreciation	37,789	29,473
	$127,019	$133,443

6. Capital Lease

Stingray leases a 36-inch pipeline from Natural Gas Pipeline Company of America ("NGPL"), an affiliate of Kinder Morgan, Inc., that connects Stingray's pipeline system to onshore Louisiana. In June 1999, the lease agreement with NGPL was extended for an additional 14 years beginning December 1, 1999, through November 30, 2013, with an option to purchase the asset at the expiration of the lease. Accordingly, Stingray accounts for this lease as a capital lease. The present value of the lease payments under the capital lease is recorded as other current and noncurrent liabilities in the accompanying balance sheet.

Future minimum lease payments under capital leases are as follows:

(in thousands of dollars) **Year Ended December 31,**	
2008	$1,073
2009	1,073
2010	1,073
2011	1,073
2012	1,073
Thereafter	2,056
Total minimum lease payments	7,421
Less: Amount representing interest	(1,583)
Present value of net minimum lease payments, including current maturities of $622	$5,838

7. Asset Retirement Obligation

Activity related to the Company's asset retirement obligation ("ARO") during the year ended December 31, 2007 and 2006, is as follows:

(in thousands of dollars)	2007	2006
Balance of ARO as of January 1	$5,936	$5,593
Liabilities incurred during period	—	19
Revisions resulting from changes in expected cash flows	(629)	—
Accretion expense	344	324
Balance of ARO as of December 31	$5,651	$5,936

For the years ended December 31, 2007, 2006 and 2005, the Company recognized depreciation expense related to its asset retirement cost ("ARC") of $505,191, $512,500 and $223,000, respectively.

The rate case filed by Stingray with the FERC (Docket No. RP99-166) decreased the amount the Company could charge in their rates ("Negative Salvage") for asset retirement obligations. Beginning in 2003, the Negative Salvage the Company was allowed to recover was 0.25% of the total value of the Stingray System (approximately $697,000 per year). The Company recognized regulatory expense of approximately $267,309, $248,237 and $363,000 during the years ended December 31, 2007, 2006 and 2005, respectively. Activity related to the Company's regulatory liability during the years ended December 31, 2007 and 2006, is as follows:

(in thousands of dollars)	2007	2006
Balance of regulatory liability as of January 1	$9,349	$9,180
Negative Salvage recovered	697	697
Current period ARO accretion (Stingray's System)	(267)	(248)
Current period ARC depreciation (Stingray's System)	(57)	(280)
Balance of regulatory liability as of December 31	$9,722	$9,349

8. Regulatory Matters

Regulatory Environment

The FERC has jurisdiction over Stingray with respect to transportation of gas, rates and charges, construction of new facilities, extension or abandonment of service facilities, accounts and records, depreciation and amortization policies and certain other matters.

An annual charge totaling $297,597, $226,948 and $337,079 was paid to the FERC for fiscal years 2007, 2006 and 2005, respectively. This charge, to be recovered from customers through rates, was recorded as a regulatory asset and will be amortized over twelve months. During 2007, 2006 and 2005, respectively, $244,610, $304,518 and $318,082 was recorded as amortization expense.

9. Commitments and Contingencies

In the ordinary course of business, Starfish and its subsidiaries are subject to various laws and regulations including regulations of the FERC. In the opinion of management, compliance with existing laws and regulations will not materially affect the financial position or results of operations of Starfish.

Various legal actions, which have arisen in the ordinary course of business, are pending with respect to the assets of the Starfish. Management believes that the ultimate disposition of these actions, either individually or in aggregate, will not have a material adverse effect on the financial position, the results of operations or cash flows of Starfish.

10. Impact of Hurricane Rita

In September 2005, Hurricane Rita ("Rita") caused substantial damage to both onshore and offshore facilities, resulting in loss of revenues and significant capital and maintenance expenditures. Onshore refurbishments were primarily complete as of December 31, 2005, and the majority of offshore refurbishments were completed as of December 31, 2006. As the Company is self insured, capital expenditures of approximately $24,218,000 and $24,051,000 and maintenance expenditures of approximately $6,724,000 and $6,356,000 have been incurred as of December 31, 2007 and 2006, respectively.

11. Supplemental Cash Flow Disclosures

Cash paid for interest for the years ended December 31, 2007, 2006 and 2005 was approximately $453,000, $495,000 and $451,000, respectively.

Noncash financing and investing activities include:

During 2007 and 2006, respectively, $0 and $19,000 of fixed asset additions were recognized due to recording of an asset retirement obligation.

A revision resulting from changes in expected cash flows decreased the asset retirement obligation and asset retirement cost by $629,148 as of December 31, 2007.

Construction in progress additions and accrued liabilities amount to approximately $1,063,000, $532,000 and $0 for the years ended December 31, 2007, 2006 and 2005, respectively.

The members agreed on December 19, 2005 to provide capital contributions in the amount of $2,972,000. As of December 31, 2005, a receivable in the amount of $1,486,000, was due from MarkWest. Starfish received the contribution in January 2006.

12. Business and Credit Concentrations

For the year ended December 31, 2007, six customers accounted for approximately 56% of revenues and 11.1% of transportation receivables. For the year ended December 31, 2006, four customers accounted for approximately 51% of revenues and 23% of transportation receivables. For the year ended December 31, 2005, two customers accounted for approximately 29% of revenues.

Exhibit Number	Description
2.1(2)	Purchase Agreement dated as of March 24, 2003, among PNG Corporation, Energy Spectrum Partners LP, MarkWest Texas GP, L.L.C., MW Texas Limited, L.L.C. and MarkWest Energy Partners, L.P.
2.2(2)	Plan of Merger entered into as of March 28, 2003, by and among MarkWest Blackhawk L.P., MarkWest Pinnacle L.P., MarkWest PNG Utility L.P., MarkWest Texas PNG Utility L.P., Pinnacle Natural Gas Company, Pinnacle Pipeline Company, PNG Transmission Company, PNG Utility Company and Bright Star Gathering, Inc.
2.3(3)	Asset Purchase-and-Sale Agreement dated as of November 18, 2003, by and between American Central Western Oklahoma Gas Company, L.L.C., MarkWest Western Oklahoma Gas Company, L.L.C. and American Central Gas Technologies, Inc.
2.4(4)	Purchase and Sale Agreement, dated as of November 7, 2003, by and between Shell Pipeline Company, LP and Equilon Enterprises L.L.C., dba Shell Oil Products US, and MarkWest Michigan Pipeline Company, L.L.C.
2.5(8)	Asset Purchase and Sale Agreement and addendum, thereto, dated as of July 1, 2004, by and between American Central Eastern Texas Gas Company Limited Partnership, ACGC Gathering Company, L.L.C. and MarkWest Energy East Texas Gas Company's L.P.
2.6(15)	Purchase and Sale Agreement effective as of January 1, 2005 between MarkWest Energy Partners L.P. and Enterprise Products Operating L.P.
2.7(16)	Purchase and Sale Agreement, dated as of September 16, 2005, by and between El Paso Corporation, as seller, and MarkWest Energy Partners, L.P. as buyer.
2.8(16)	Purchase and Sale Agreement, dated as of September 16, 2005, by and between Kerr McGee Corp., KM Investment Corp., and Javelina Holdings Corp., as joint sellers, and MarkWest Energy Partners, L.P. as buyer.
2.9(16)	Purchase and Sale Agreement, dated as of September 16, 2005, by and between Valero Energy Corp., and Valero Javelina, L.P., as sellers, and MarkWest Energy Partners, L.P. as buyer.
2.10(31)	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.
3.1(1)	Certificate of Limited Partnership of MarkWest Energy Partners, L.P.
3.2(5)	Amended and Restated Agreement of Limited Partnership of MarkWest Energy Partners, L.P., dated as of May 24, 2002.
3.3(1)	Certificate of Formation of MarkWest Energy Operating Company, L.L.C.
3.4(5)	Amended and Restated Limited Liability Company Agreement of MarkWest Energy Operating Company, L.L.C., dated as of May 24, 2002.
3.5(1)	Certificate of Formation of MarkWest Energy GP, L.L.C.
3.6(5)	Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of May 24, 2002.
3.7(12)	Amendment No. 1 to Amended and Restated Limited Partnership Agreement MarkWest Energy Partners, L.P.
3.8(23)	Amendment No. 2 to Amended and Restated Limited Partnership Agreement MarkWest Energy Partners, L.P.
3.9(28)	Amendment No. 3 to Amended and Restated Limited Partnership Agreement MarkWest Energy Partners, L.P.
4.1(6)	Purchase Agreement dated as of June 13, 2003, by and among MarkWest Energy Partners, L.P. and Tortoise Capital Advisors, LLC as attorney-in-fact for the Purchasers.
4.2(6)	Registration Rights Agreement dated as of June 13, 2003, by and among MarkWest Energy Partners, L.P. and Tortoise Capital Advisors, LLC as attorney-in-fact for the Purchasers.

Exhibit Number	Description
4.3(8)	Unit Purchase Agreement dated as of July 29, 2004 among MarkWest Energy Partners, L.P., and MarkWest Energy GP, L.L.C. and each of Kayne Anderson Energy Fund II, L.P., and MarkWest Energy GP, L.L.C. and each of Kayne Anderson Energy Fund II, L.P., Kayne Anderson Capital Income Partners, L.P., Kayne Anderson MLP Fund, L.P., Kayne Anderson Capital Income Fund, LTD., Kayne Anderson Income Partners, L.P., HFR RV Performance Master Trust, Tortoise Energy Infrastructure Corporation and Energy Income and Growth Fund as Purchasers.
4.4(8)	Registration Rights Agreement dated as of July 29, 2004, among MarkWest Energy Partners, L.P., and each of Kayne Anderson Energy Fund II, L.P., Kayne Anderson Capital Income Fund, LTD., Kayne Anderson Income Partners, L.P., HFR RV Performance Master Trust, Tortoise Energy Infrastructure Corporation and Energy Income and Growth Fund.
4.5(10)	Purchase Agreement dated October 19, 2004, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein.
4.6(10)	Registration Rights Agreement dated October 25, 2004, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein.
4.7(10)	Indenture dated as of October 25, 2004, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as Trustee.
4.8(10)	Form of 6.875% Series A Senior Notes due 2014 with attached notation of Guarantees (incorporated by Reference to Exhibits A and D of Exhibit 4.7 hereto)
4.9(17)	Registration Rights Agreement, dated as of November 9, 2005
4.10(17)	Unit Purchase Agreement, dated as of November 9, 2005
4.11(18)	Registration Rights Agreement, dated as of December 23, 2005
4.12(18)	Unit Purchase Agreement, dated as of December 23, 2005
4.13(24)	Registration Rights Agreement dated as of July 6, 2006 among MarkWest Energy Partners, L.P., with MarkWest Energy Finance Corporation as the Issuers, the Guarantors named therein, and each of RBC Capital Markets Corporation, J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC, A.G. Edwards & Sons, Inc., Credit Suisse Securities (USA) LLC, Fortis Securities LLC, Mizuho International plc, Piper Jaffray & Co. and SG Americas Securities, LLC collectively as Initial Purchasers.
4.14(24)	Indenture dated as of July 6, 2006, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, as Issuers, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.15(24)	Form of 8.5% Series A and Series B Senior Notes due 2016 with attached notation of Guarantees (incorporated by Reference to Exhibits A and D of Exhibit 4.11 hereto.
4.16(25)	Registration Rights Agreement dated as of October 20, 2006 among MarkWest Energy Partners, L.P., with MarkWest Energy Finance Corporation as the Issuers, the Guarantors named therein, and RBC Capital Markets as the Initial Purchaser.
4.17(30)	Unit Purchase Agreement dated April 9, 2007 by and among MarkWest Energy Partners, L.P., MarkWest Energy G.P., L.L.C., and each of Kayne Anderson MLP Investment Company, GPS Income Fund, L.P., GPS High Yield Equities Fund, L.P., GPS New Equity Fund, L.P., Agile Performance Fund, L.L.C., Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation, Royal Bank of Canada, Structured Finance Americas, L.L.C., The Cushing MLP Opportunity Fund I, L.P., and ZLP Fund, L.P. as purchasers.
4.18(30)	Registration Rights Agreement dated April 9, 2007 by and between MarkWest Energy Partners, L.P., and each of Kayne Anderson MLP Investment Company, GPS Income Fund, L.P., GPS High Yield Equities Fund, L.P., GPS New Equity Fund, L.P., Agile Performance Fund, L.L.C., Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation, Royal Bank of Canada, Structured Finance Americas, L.L.C., The Cushing MLP Opportunity Fund I, L.P., and ZLP Fund, L.P. as purchasers.
4.19(36)	Unit Purchase Agreement, dated as of December 18, 2007
4.20(36)	Registration Rights Agreement, dated as of December 18, 2007

Exhibit Number	Description
10.1(5)	Credit Agreement dated as of May 20, 2002, among MarkWest Energy Operating Company, L.L.C (as the Borrower), MarkWest Energy Partners, L.P. (as a Guarantor), Bank of America (as Administrative Agent), and Lenders Party Hereto $60,000,000 Senior Credit Facility, and Banc of America Securities, L.L.C. as sole lead arranger and book manager.
10.2(3)	Amended and Restated Credit Agreement dated as of December 1, 2003, among MarkWest Energy Operating Company, L.L.C., as Borrower, MarkWest Energy Partners, L.P., as Guarantor, Royal Bank of Canada, as Administrative Agent, Bank One, NA, as Syndication Agent, Fortis Capital Corp., as Documentation Agent, to the $140,000,000 Senior Credit Facility.
10.3(5)	Contribution, Conveyance and Assumption Agreement dated as of May 24, 2002, by and among MarkWest Energy Partners, L.P.; MarkWest Energy Operating Company, L.L.C.; MarkWest Energy GP, L.L.C.; MarkWest Michigan, Inc.; MarkWest Energy Appalachia, L.L.C.; West Shore Processing Company, L.L.C.; Basin Pipeline, L.L.C.; and MarkWest Hydrocarbon, Inc.
10.4(5)	MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.5(5)	First Amendment to MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.6(5)	Omnibus Agreement dated of May 24, 2002, among MarkWest Hydrocarbon, Inc.; MarkWest Energy GP, L.L.C.; MarkWest Energy Partners, L.P.; and MarkWest Energy Operating Company, L.L.C.
10.7(5)+	Fractionation, Storage and Loading Agreement dated as of May 24, 2002, between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.8(5)+	Gas Processing Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.9(5)+	Pipeline Liquids Transportation Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.10(5)	Natural Gas Liquids Purchase Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.11+	Gas Processing Agreement (Maytown) dated as of May 28, 2002, between Equitable Production Company and MarkWest Hydrocarbon, Inc.
10.12+	Amendment to Gas Processing Agreement (Maytown) dated as of March 26, 2002, between Equitable Production Company and MarkWest Hydrocarbon, Inc.
10.13(7)	Services Agreement dated January 1, 2004 between MarkWest Energy GP, L.L.C. and MarkWest Hydrocarbon, Inc.
10.14(8)	Second Amended and Restated Credit Agreement dated as of July 30, 2004 among MarkWest Energy Operating Company, L.L.C., as Borrower, MarkWest Energy Partners, L.P., as Guarantor, Royal Bank of Canada, as Administrative Agent, Fortis Capital Corp., as Syndication Agent, Bank One, NA, as Documentation Agent and Societe Generale, as Documentation Agent to the $315,000,000 Senior Credit Facility.
10.15(8)	First Amendment to the Second Amended and Restated Credit Agreement dated as of August 20, 2004, among MarkWest Energy Operating Company, L.L.C., as Borrower, MarkWest Energy Partners, L.P., as Guarantor, Royal Bank of Canada, as Administrative Agent, Fortis Capital Corp., as Syndication Agent, Bank One, NA, as Documentation Agent and Societe Generale, as Documentation Agent.
10.16(11)	Third Amended and Restated Credit Agreement dated as of October 25, 2004 among MarkWest Energy Operating Company, L.L.C., as Borrower, MarkWest Energy Partners, L.P., as Guarantor, Royal Bank of Canada, as Administrative Agent, Bank One, N.A., as Syndication Agent, Fortis Capital Corp., as Documentation Agent, U.S. Bank National Association, as Documentation Agent, Societe Generale, as Documentation Agent, and Wachovia Bank, National Association, as Documentation Agent, RBC Capital Markets and J.P. Morgan Securities Inc., as Lead Arrangers and Joint Bookrunners, to the $200,000,000 Senior Credit Facility.
10.18(14)Δ	Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Frank Semple.

Exhibit Number	Description
10.19(19)	Fourth Amended and Restated Credit Agreement, dated as of November 1, 2005, among MarkWest Energy Operating Company, L.L.C., as borrower, MarkWest Energy Partners, L.P., as Guarantor, Royal Bank of Canada, as Administrative Agent, JP Morgan Chase Bank, N.A., as Co-Syndication Agent, Fortis Capital Corp., as Co-Syndication Agent, Societe Generale, as Co-Documentation Agent, Wachovia Bank, National Association, as Co-Documentation Agent and RBC Capital Markets, as Sole Lead Arranger and Bookrunner to the $100,000,000 Revolver Facility and $400,000 Term Loan.
10.20(20)	Fifth amended and restated credit agreement dated as of December 29, 2005, among MarkWest Energy Operating Company, L.L.C., as Borrower, MarkWest Energy Partners, L.P., as Guarantor, Royal Bank of Canada, as Administrative Agent, Bank One, N.A., as Syndication Agent, Forties Capital Corp., as Documentation Agent, U.S. Bank National Association, as Documentation Agent, Society General, as Documentation Agent, and Wachovia Bank, National Association, as Documentation Agent, RBC Capital Markets and J.P. Morgan Securities Inc., as Lead Arrangers and Joint Bookrunners, to the $615,000,000 Senior Credit Facility.
10.21(26)	Office Lease Agreement, dated April 19, 2006, by and between Park Central Property LLC, the landlord, and MarkWest Energy Partners, L.P., the tenant.
10.22(14)Δ	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.
10.23(29)	Form of Indemnification Agreement between MarkWest Energy Partners, LLP and each Non-employee Director and the following Officers of the Company: 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; C. Corwin Bromley, Senior Vice President, General Counsel and Secretary; David Young, Senior Vice President of Corporate Services; Richard Ostberg, Vice President of Risk and Compliance, and Andrew Schroeder, Vice President and Treasurer dated as of January 26, 2007.
10.24(31)	Exchange Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P., MarkWest Hydrocarbon, Inc., and MarkWest Energy, GP L.L.C.
10.25(31)	Voting Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P. and the Fox Family Holders.
10.26(34)+	Hydrogen Supply Agreement dated September 28, 2007, by and between MarkWest Blackhawk, L.P. and CITGO Refining and Chemicals Company L.P.
10.27(32)	Amended and Restated Class B Membership Interest Contribution Agreement dated October 26, 2007 by and among MarkWest Energy Partners, L.P. and John M. Fox, Donald C. Heppermann, Frank M. Semple, Nancy K. Buese, Randy S. Nickerson, John C. Mollenkopf, C. Corwin Bromley, Andrew L. Schroeder, Jan Kindrick, Cindy Kindrick, Kevin Kubat and Art Denney as the Sellers.
10.28(33)	Amended and Restated Form of Indemnification Agreement dated October 26, 2007 by and between MarkWest Energy Partners, L.P. and each non-employee director and executive officer of the General Partner, 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; C. Corwin Bromley, Senior Vice President, General Counsel and Secretary and Andrew Schroeder, Vice President and Treasurer.
10.29*+	Gas Processing Agreement dated as of November 1, 2007, by and between MarkWest Javelina Company and CITGO Refining and Chemicals Company, L.P.
10.30*+	Amendment to Gas Processing Agreement dated as of December 11, 2007, by and between MarkWest Javelina Company and CITGO Refining and Chemicals Company, L.P.
10.31(35)	Amended Class B Membership Interest Contribution Agreement dated as of October 26, 2007, to Agreement and Plan of Redemption and Merger by and among the Partnership, MarkWest Hydrocarbon, Inc. and MWEP, L.L.C.
10.32*	Omnibus Termination Agreement dated as of November 16, 2007, by and between MarkWest Energy Appalachia, L.L.C. and Equitable Production Company and Equitable Gathering LLC

Exhibit Number	Description
10.33*+	Natural Gas Liquids Transportation, Fractionation, and Marketing Agreement dated as of November 16, 2007, by and between MarkWest Energy Appalachia, L.L.C. and Equitable Gathering LLC
10.34*	Assignment and Bill of Sale and Assumption Agreement dated as of November 16, 2007, by and between MarkWest Energy Appalachia, L.L.C. and Equitable Production Company and Equitable Gathering LLC
10.35*+	Second Amendment to the Gas Processing Agreement dated as of December 26, 2007, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
16.1(22)	Changes in registrants certifying accountants. MarkWest Energy Partners, L.P. dismissed KPMG LLP as the Partnership's independent registered public accounting firm and engaged Deloitte & Touche LLP as its new independent registered public accounting firm.
21.1*	List of subsidiaries
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of PricewaterhouseCoopers LLP
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.

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(1) Incorporated by reference to the Registration Statement (No. 33-81780) on Form S-1 filed January 31, 2002.

(2) Incorporated by reference to the Current Report on Form 8-K filed April 14, 2003.

(3) Incorporated by reference to the Current Report on Form 8-K filed December 16, 2003.

(4) Incorporated by reference to the Current Report on Form 8-K filed December 31, 2003.

(5) Incorporated by reference to the Current Report on Form 8-K filed June 7, 2002.

(6) Incorporated by reference to the Current Report on Form 8-K filed June 19, 2003.

(7) Incorporated by reference to the Annual Report on Form 10-K filed March 15, 2004.

(8) Incorporated by reference to the Current Report on form 8-K/A filed September 13, 2004.

(9) Incorporated by reference to the Current Report on Form 8-K filed September 20, 2004.

(10) Incorporated by reference to the Current Report on Form 8-K filed October 25, 2004.

(11) Incorporated by reference to the Current Report on Form 8-K filed October 29, 2004.

(12) Incorporated by reference to the Current Report on Form 8-K filed January 6, 2005.

(13) Incorporated by reference to the Quarterly Report of MarkWest Hydrocarbon, Inc. on Form 10-Q filed November 13, 1997.

(14) Incorporated by reference to the Current Report on Form 8-K filed September 11, 2007.

(15) Incorporated by reference to the Current Report on Form 8-K filed April 6, 2005.

(16) Incorporated by reference to the Current Report on Form 8-K filed September 21, 2005.

(17) Incorporated by reference to the Current Report on Form 8-K filed November 16, 2005.

(18) Incorporated by reference to the Current Report on Form 8-K/A filed December 29, 2005.

(19) Incorporated by reference to the Current Report on Form 8-K filed November 7, 2005.

(20) Incorporated by reference to the Current Report on Form 8-K filed January 5, 2006.

(21) Incorporated by reference to the Current Report on Form 8-K filed March 1, 2004.

(22) Incorporated by reference to the Current Report on Form 8-K filed September 23, 2005.

(23) Incorporated by reference to the Current Report on Form 8-K filed June 15, 2005.

(24) Incorporated by reference to the Current Report on Form 8-K filed July 7, 2006.

(25) Incorporated by reference to the Current Report on Form 8-K filed October 24, 2006.

(26) Incorporated by reference to the Current Report on Form 8-K filed April 25, 2006.

(27) Incorporated by reference to the Current Report on Form 8-K filed November 1, 2006.

(28) Incorporated by reference to the Current Report on Form 8-K filed January 31, 2007.

(29) Incorporated by reference to the Annual Report on Form 10-K filed March 7, 2007.

(30) Incorporated by reference to the Current Report on Form 8-K filed April 11, 2007.

(31) Incorporated by reference to the Current Report on Form 8-K filed September 6, 2007.

(32) Incorporated by reference to the Current Report on Form 8-K filed November 13, 2007.

(33) Incorporated by reference to the Current Report on Form 8-K filed November 1, 2007.

(34) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 8, 2007.

(35) Incorporated by reference to the Current Report on Form 8-K filed November 13, 2007.

(36) Incorporated by reference to the Current Report on Form 8-K filed December 19, 2007.

+ 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 29, 2008

By: /s/ FRANK M. SEMPLE
Frank M. Semple
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 29, 2008

By: /s/ FRANK M. SEMPLE
Frank M. Semple
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 29, 2008

By: /s/ NANCY K. BUESE
Nancy K. Buese
Senior Vice President & Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)

Date: February 29, 2008

By: /s/ JOHN M. FOX
John M. Fox
Chairman of the Board and Director

Date: February 29, 2008

By: /s/ KEITH E. BAILEY
Keith E. Bailey
Director

Date: February 29, 2008

/s/ MICHAEL L. BEATTY
Michael L. Beatty
Director

Date: February 29, 2008

By: /s/ CHARLES K. DEMPSTER
Charles K. Dempster
Director

Date: February 29, 2008

By: /s/ DONALD C. HEPPERMANN
Donald C. Heppermann
Director

Date: February 29, 2008

By: /s/ WILLIAM A. KELLSTROM
William A. Kellstrom
Director

Date: February 29, 2008		/s/ ANNE E. MOUNSEY Anne E. Mounsey *Director*
Date: February 29, 2008	By:	/s/ WILLIAM P. NICOLETTI William P. Nicoletti *Director*
Date: February 29, 2008		/s/ DONALD D. WOLF Donald D. Wolf *Director*

Directors and Officers

Board of Directors of MarkWest Energy GP, LLC

John M. Fox
Chairman of the Board
Retired President and Chief Executive Officer
MarkWest Energy GP, LLC
MarkWest Hydrocarbon, Inc.

Frank M. Semple
President and Chief Executive Officer
MarkWest Energy GP, LLC

Keith E. Bailey (1) (2)
Chairman of the Audit Committee
Retired Chairman, President, and
Chief Executive Officer
The Williams Companies, Inc.

Michael L. Beatty (3)
Chairman and Chief Executive Officer
Beatty & Wozniak, PC

Charles K. Dempster (2)
Chairman of the Compensation Committee
Retired Executive
Aquila, Inc.

Donald C. Heppermann (1) (3)
Chairman of the Nominating and
Corporate Governance Committee
Retired Chief Financial Officer
MarkWest Energy GP, LLC
MarkWest Hydrocarbon, Inc.

William A. Kellstrom (1) (2)
Retired Executive
Reliant Energy, Inc.

Anne E. Fox Mounsey
Former Manager
MarkWest Energy GP, LLC
MarkWest Hydrocarbon, Inc.

William P. Nicoletti (1) (3)
Managing Director
Nicoletti & Company, Inc.

Donald D. Wolf (2)
President and Chief Executive Officer
Aspect Energy, LLC
Chief Executive Officer
Quantum Resources, LLC

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Nominating and Corporate Governance Committee

Executive Officers of MarkWest Energy GP, LLC

Frank M. Semple
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 Operations Officer

Randy S. Nickerson
Senior Vice President and
Chief Commercial Officer

Andrew L. Schroeder
Vice President Finance and Treasurer

Unitholder Information

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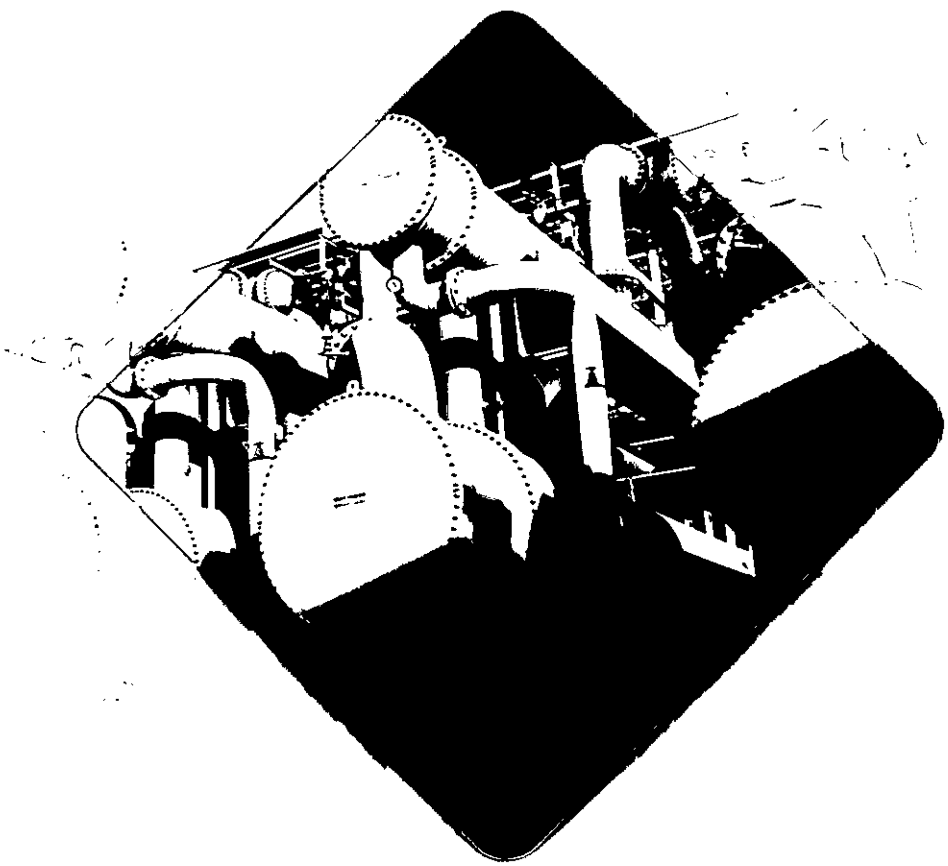
New York Stock Exchange: MWE

Transfer Agent and Registrar

Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, Minnesota 55075
Tel: 800.468.9716



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CORE PRINCIPLES

MarkWest believes every employee is important to the company and its success, and we are committed to build a culture based on trust, accountability, safety and teamwork.

MarkWest is focused on delivering best-of-class service. MarkWest will seek true understanding of our customers' requirements and will strive to provide solutions exceeding their expectations.

MarkWest will aim for innovative concepts in all that we do, and the company will support and encourage the search for innovation at all levels. Creation of substantial value will be the primary criteria for any new endeavor.

MarkWest seeks a fair profit and will maintain a strong balance sheet and appropriate expense controls through continuous process improvements.

MarkWest's reputation rests on our ability to act with honesty, integrity, and trustworthiness. To that end, we have adopted and communicated our Code of Conduct & Ethics as the cornerstone of our business.

MARKWEST
Energy Partners, L.P.

MarkWest Energy Partners, L.P.
1515 Arapahoe Street
Tower 2, Suite 700
Denver, Colorado 80202-2126
www.markwest.com

END