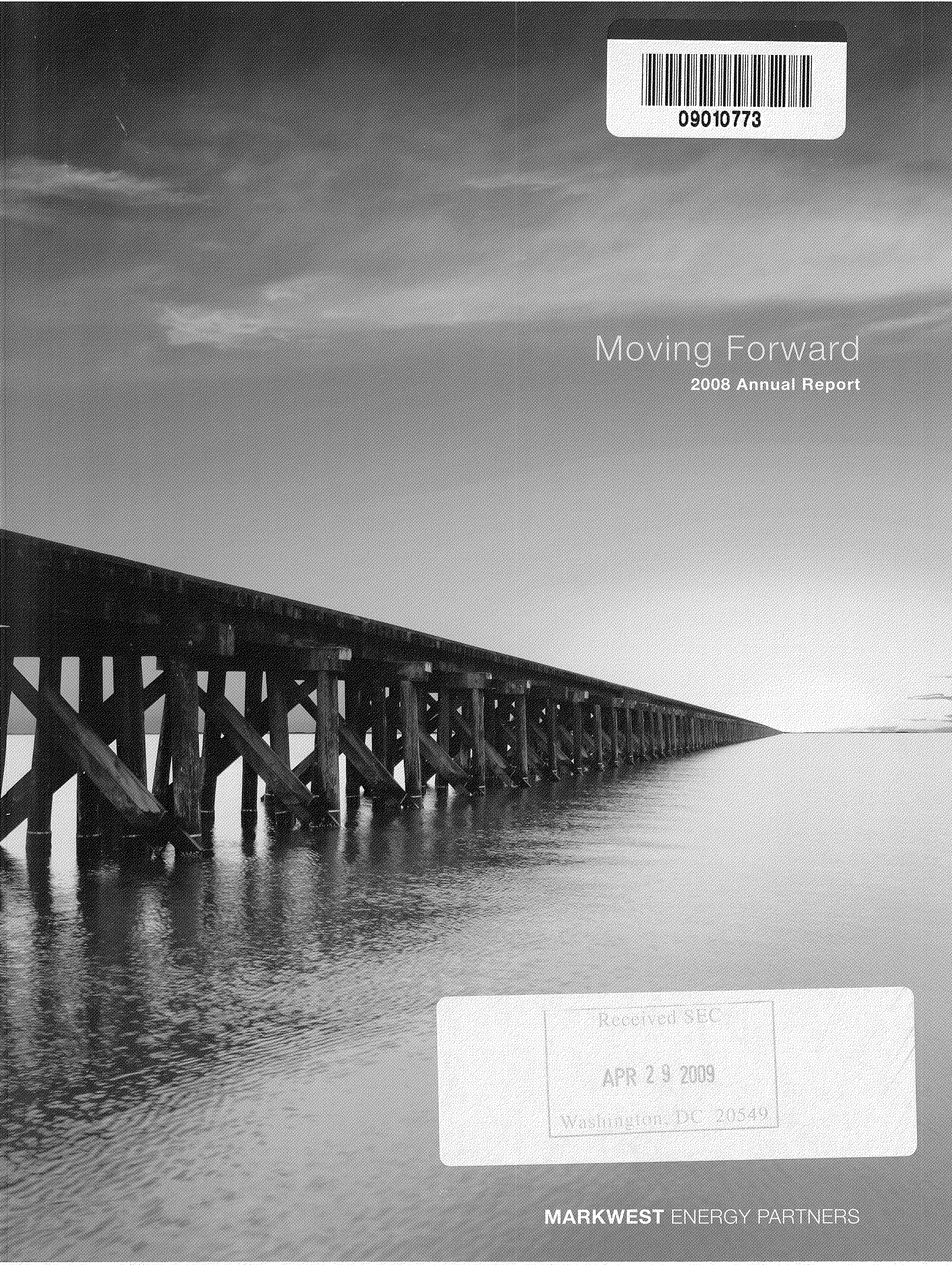


Moving Forward

2008 Annual Report

MARKWEST ENERGY PARTNERS

Financial and Operating Summary

Selected Financial Data

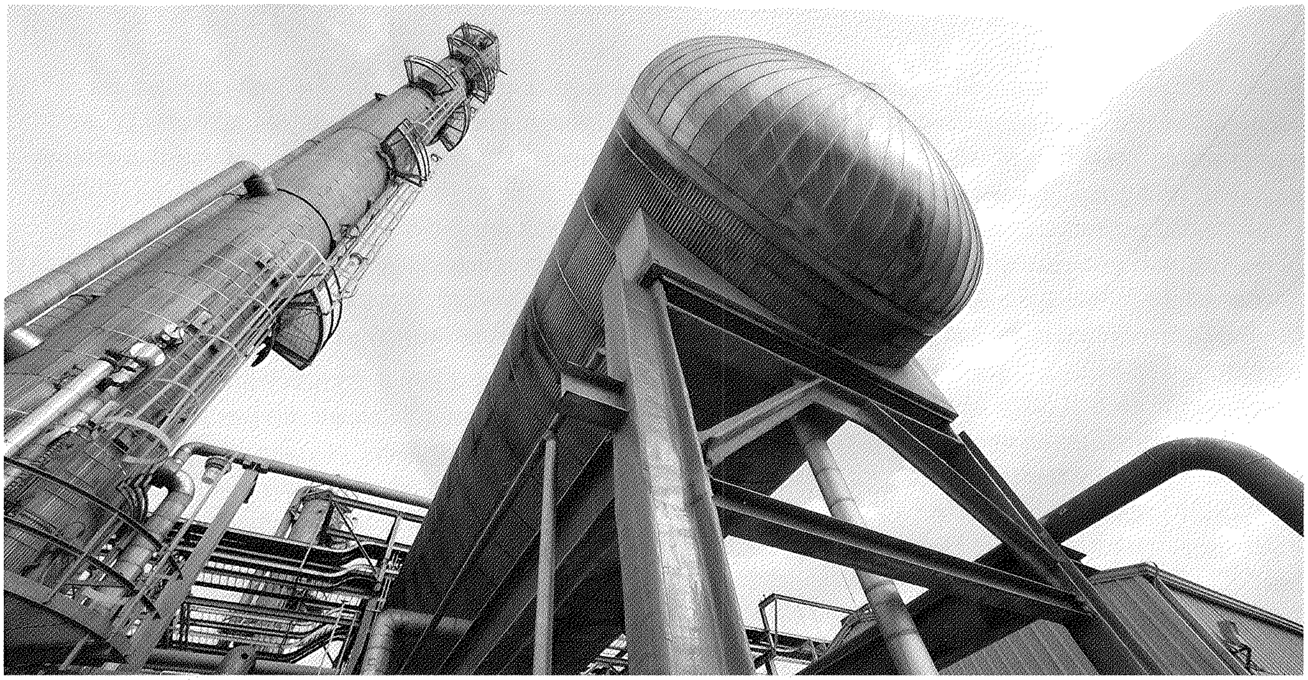
($000, except per unit data)	2006	2007	2008
	Years ended December 31,		
Revenue	$ 839,681	$ 685,757	$ 1,338,490
Net income (loss)	$ 9,537	$ (39,359)	$ 208,073
Net income (loss) per common unit			
Basic	$ 0.42	$ (1.72)	$ 4.08
Diluted	$ 0.42	$ (1.72)	$ 4.04
Weighted average common units outstanding			
Basic	22,745	22,854	51,013
Diluted	22,924	22,854	51,560
Declared distributions per common unit	$ 0.42	$ 0.70	$ 2.06
Cash Flow Data			
Net cash flow provided by (used in):			
Operating activities	$ 165,969	$ 133,237	$ 226,995
Investing activities	$ (122,046)	$ (314,792)	$ (909,265)
Financing activities	$ (16,047)	$ 170,406	$ 647,896
Other Financial Data			
Distributable cash flow *	$ 117,911	$ 162,611	$ 198,080
Adjusted EBITDA *	$ 189,812	$ 220,384	$ 289,012
Balance Sheet Data			
Working capital	$ 66,030	$ 21,932	$ 51,237
Total assets	$ 1,203,241	$ 1,524,695	$ 2,673,054
Total debt	$ 526,865	$ 552,695	$ 1,172,965
Partners' capital	$ 41,489	$ 39,391	$ 1,204,458

Operating Data

	2006	2007	2008
	Years ended December 31,		
Southwest			
East Texas			
Gathering systems throughput (Mcf/d)	378,100	413,700	442,900
NGL product sales (gallons)	161,437,000	179,601,000	193,534,100
Oklahoma			
Foss Lake gathering system throughput (Mcf/d)	87,500	104,000	95,800
Stiles Ranch gathering system throughput (Mcf/d)	N/A	N/A	84,800
Grimes gathering system throughput (Mcf/d)	N/A	12,500	12,900
Arapaho NGL product sales (gallons)	79,093,000	87,522,000	79,416,400
Southeast Oklahoma gathering system throughput (Mcf/d)	34,000	114,000	318,700
Other Southwest			
Appleby gathering system throughput (Mcf/d)	34,200	58,700	58,400
Other gathering systems throughput (Mcf/d)	18,300	8,700	11,000
Northeast			
Appalachia			
Keep-whole sales (gallons)	118,581,000	126,192,600	140,847,500
Percent-of-proceeds sales (gallons)	43,271,000	43,815,100	53,987,900
Total NGL product sales (gallons)	161,852,000	170,007,700	194,835,400
Natural gas processed (Mcf/d)	203,000	200,200	202,200
Marcellus Shale			
Natural gas processed (Mcf/d)	N/A	N/A	18,700
Michigan			
Natural gas processed for a fee (Mcf/d)	6,500	5,200	3,200
NGL product sales (gallons)	5,643,000	3,898,600	2,954,400
Crude oil transported for a fee (Bbl/d)	14,500	14,000	13,300
Gulf Coast			
Javelina			
Refinery off-gas processed (Mcf/d)	124,300	114,500	122,900
Liquids fractionated (Bbl/d)	26,200	25,000	24,400

On February 21, 2008, MarkWest Energy Partners, L.P. (Partnership) completed its plan of redemption and merger (Merger) with MarkWest Hydrocarbon, Inc. (MarkWest Hydrocarbon), pursuant to which MarkWest Hydrocarbon was merged into the Partnership. For accounting purposes, MarkWest Hydrocarbon was viewed as the surviving consolidated entity rather than the Partnership, which is the surviving consolidated entity for legal purposes. As a result, the historical and comparative consolidated financial statements for the surviving legal entity included in the enclosed Annual Report on Form 10-K are those of MarkWest Hydrocarbon, the accounting acquirer, rather than those of the Partnership, the legal acquirer. Accordingly, the historical selected financial information presented above for the years ended 2007 and 2006, with the exception of Distributable Cash Flow (DCF) and Adjusted EBITDA*, represents the consolidated results and financial position of MarkWest Hydrocarbon. DCF and Adjusted EBITDA for the years ended 2007 and 2006 represent the Partnership results as reported prior to the Merger because DCF is a measure of performance that was not applicable to MarkWest Hydrocarbon. The Merger involved borrowings of $225 million and the issuance of additional common units but also eliminated the incentive distribution rights. As such, the Merger contributed significantly to the increase in DCF in 2008 compared to 2007. Additionally, as part of the Merger, the shareholders of MarkWest Hydrocarbon exchanged each share of MarkWest Hydrocarbon common stock for consideration equal to 1.9051 Partnership common units (Exchange Ratio). All historical unit and per unit data presented above has been adjusted to reflect the Exchange Ratio to give the effect to the Merger. See Note 3 to the Consolidated Financial Statements in the enclosed Annual Report on Form 10-K for further discussion of the costs associated with the Merger.

*DCF and Adjusted EBITDA are non-GAAP financial measures. The GAAP measure most directly comparable to DCF and Adjusted EBITDA is net income. In general, we define DCF as net income or loss, plus (i) depreciation, amortization, accretion, and impairment expense; (ii) non-cash earnings from unconsolidated affiliates; (iii) contributions to unconsolidated affiliates net of growth capital expenditures; (iv) non-cash compensation expense; (v) non-cash derivative activity; (vi) gain / loss on disposal of assets; less (vii) maintenance capital expenditures. We define Adjusted EBITDA as net income, plus (i) depreciation, amortization, accretion, and impairment expense; (ii) interest expense; (iii) amortization of deferred financing costs; (iv) gain / loss on disposal of assets; (v) non-cash derivative activity; (vi) non-cash compensation expense; and (vii) adjustments for cash flow from non-consolidated investments. DCF and Adjusted EBITDA are not measures of performance calculated in accordance with GAAP, and should not be considered in isolation or as a substitute for net income, income from operations, or cash flow as reflected in our financial statements. Please see the Form 8-K we filed on April 23, 2009, for our calculations of DCF and Adjusted EBITDA along with the corresponding reconciliations to net income, and management's reasons for including such financial measures in this Annual Report.



Company Profile

MarkWest is a master limited partnership engaged in the gathering, transportation, and processing of natural gas and refinery off-gas; the transportation, fractionation, marketing, and storage of natural gas liquids (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, and we are the largest natural gas processor in the Appalachian region of the United States.

Our primary business strategy is to provide outstanding customer service at competitive rates, maintain financial flexibility, expand operations through organic growth projects and strategic acquisitions, increase utilization of facilities, and reduce the sensitivity of cash flows to commodity price fluctuations. This strategy revolves around our focus on sustainable distribution growth for our common unitholders over the long term.

As a result of the redemption and merger with MarkWest Hydrocarbon in February 2008, we extinguished the incentive distribution rights (IDRs) normally associated with a master limited partnership. Elimination of the IDRs resulted in lower cost of equity capital and immediate accretion to cash available for distribution to common unitholders.

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 2008, 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

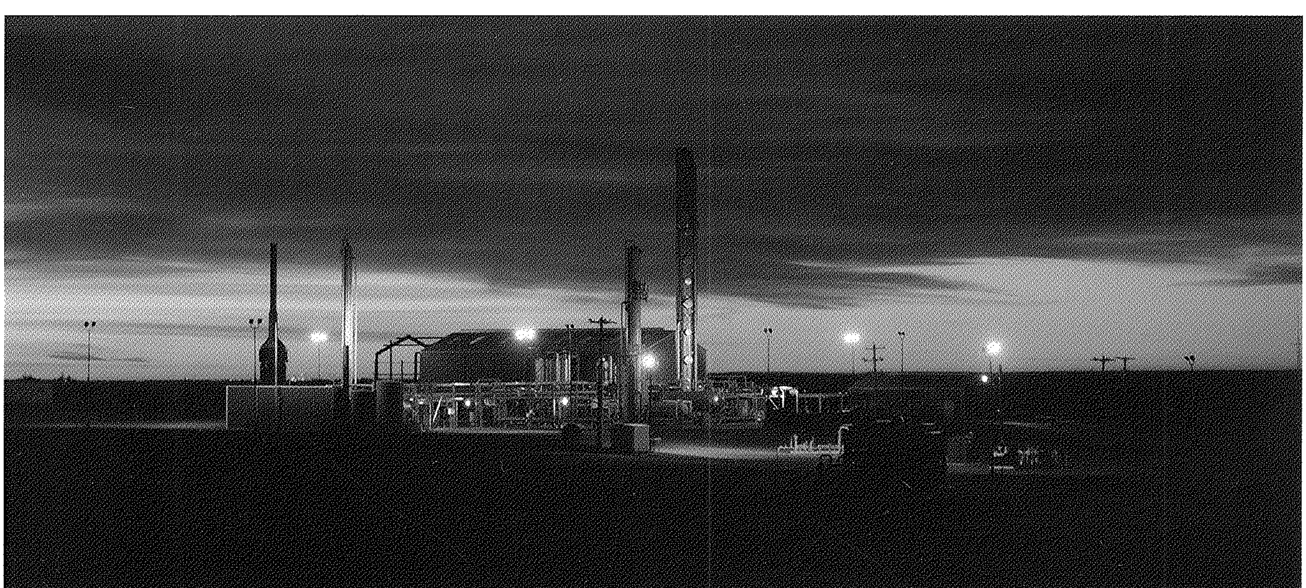
While 2008 proved to be a challenging year, with global economic instability and unprecedented volatility in energy prices, we delivered solid financial results, including strong year-over-year distribution growth. Our financial performance during the first three quarters of the year was particularly strong, and our fourth quarter results reflected the deteriorating economic conditions that existed in the last part of the year. In 2008 we executed an extensive growth capital program, with expansions in each of our core operating areas, while maintaining our focus on operational execution and customer service. Financial highlights for 2008 include $289 million in adjusted EBITDA* and $198 million in distributable cash flow.* As of December 31, 2008, we had $2.7 billion in assets, $1.2 billion in total debt, and a debt-to-capitalization ratio of 49 percent.

Our 2008 financial results allowed us to increase unitholder distributions to $2.51 per unit for 2008, a year-over-year increase of 16 percent compared to 2007. Since going public in 2002, we have delivered total distribution growth of 156 percent.

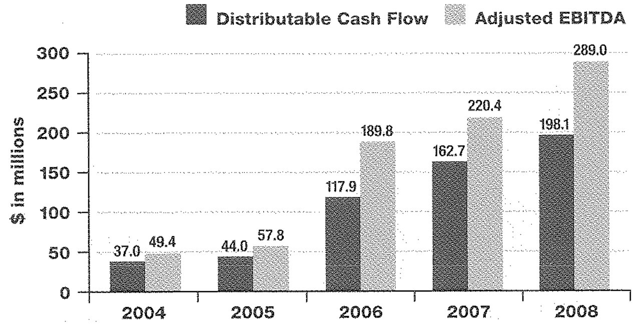
In early 2008, we completed the merger between MarkWest Hydrocarbon and MarkWest Energy Partners. The merger was a very significant transaction that resulted in the elimination of incentive distribution rights, which substantially lowers our equity cost of capital and increases the cash available for distribution to our unitholders, thereby enhancing long-term value for our unitholders. Another important benefit of the merger is the simplification of our corporate structure.

We continue to execute our hedge philosophy to manage the risk associated with commodity price exposure and to meet our distribution objectives by hedging certain commodity components of our business. The comprehensive hedge program extends through the end of 2011, consistent with our rolling 36-month commodity risk management objectives, with approximately 80 percent of our 2009 commodity exposure hedged through a combination of fixed-price swaps, costless collars, and puts.

Our capital program is primarily driven by the expansion of our midstream services required to meet our producer customers' ongoing drilling programs. In 2008, we spent approximately $640 million to expand the midstream infrastructure of our core operating areas. Key projects in our Southwest segment include the significant expansion of our Woodford system in southeast Oklahoma, including an equity investment in a gas processing plant; the extension of our western Oklahoma system into the Texas Panhandle and the associated expansion of our Arapaho processing plant; the expansion of our Carthage processing plant; and the initial construction on the Arkoma Connector pipeline, which will transport gas from southeast Oklahoma to an interconnect with Midcontinent Express Pipeline (MEP) and Gulf Crossing Pipeline. In our Northeast segment, we expanded our Appalachian facilities to significantly increase processing and fractionation capacity and extended our footprint to establish a significant midstream infrastructure presence in the emerging Marcellus Shale play. In our Gulf Coast segment, we commenced construction on a steam methane reformer, which will be operational in 2010.



Financial Performance*



One of our key objectives is to anticipate and stay ahead of the financing requirements for our capital program. In the second quarter of 2008, we raised $660 million in net capital through the placement of $500 million in senior notes at 8.75 percent and the completion of an equity offering of 5.75 million units at just over $31 per unit. Both offerings were significantly oversubscribed, and the proceeds from the offerings were used to pay down debt and partially fund our 2008 growth capital.

As we look ahead, our primary focus is the continued strength of our balance sheet in 2009 and beyond. We are proactively and aggressively managing the challenges for 2009 and 2010 while still preserving future opportunities to create long-term value for our unitholders.

During the first quarter of 2009, we took steps to strengthen our liquidity to support our 2009 capital plan, which we anticipate will be approximately $200 million. These steps include expanding our credit facility and entering into a partnership with Midstream & Resources (M&R) to develop midstream infrastructure in the Marcellus. The expansion of our credit facility was completed at favorable terms in a challenging lending environment and increased borrowing capacity by $85.6 million to $435.6 million. The partnership with M&R provides a number of important benefits, including a strong partner that brings deep insight and support to our efforts in the Marcellus, the ability to meet the needs of producers with a significantly reduced up-front investment on our part, and capital flexibility to maintain our position as the premier provider of midstream services in the Marcellus. MarkWest contributed approximately $100 million in assets to the partnership that is owned 60 percent by MarkWest and 40 percent by M&R. M&R will contribute the next $200 million in capital, which will support our 2009 capital program related to the Marcellus. We have worked diligently with producers to meet their long-term requirements, and the M&R partnership will allow us to meet our commitments while at the same time optimizing our capital investment in the Marcellus.

Our diverse assets are situated in some of the best resource plays in the United States. As evidenced by our recent success in the Marcellus and the Woodford, we continue to be in a great position to participate in the significant need for quality midstream infrastructure to support the demand for natural gas. As a result of the quality of our customers, the ingenuity and dedication of our people, and the location of our core operations, we continue to uncover significant opportunities. However, we anticipate that access to the capital markets may be challenging for a period of time, and we will balance the economics of future growth opportunities with the availability and cost of capital.

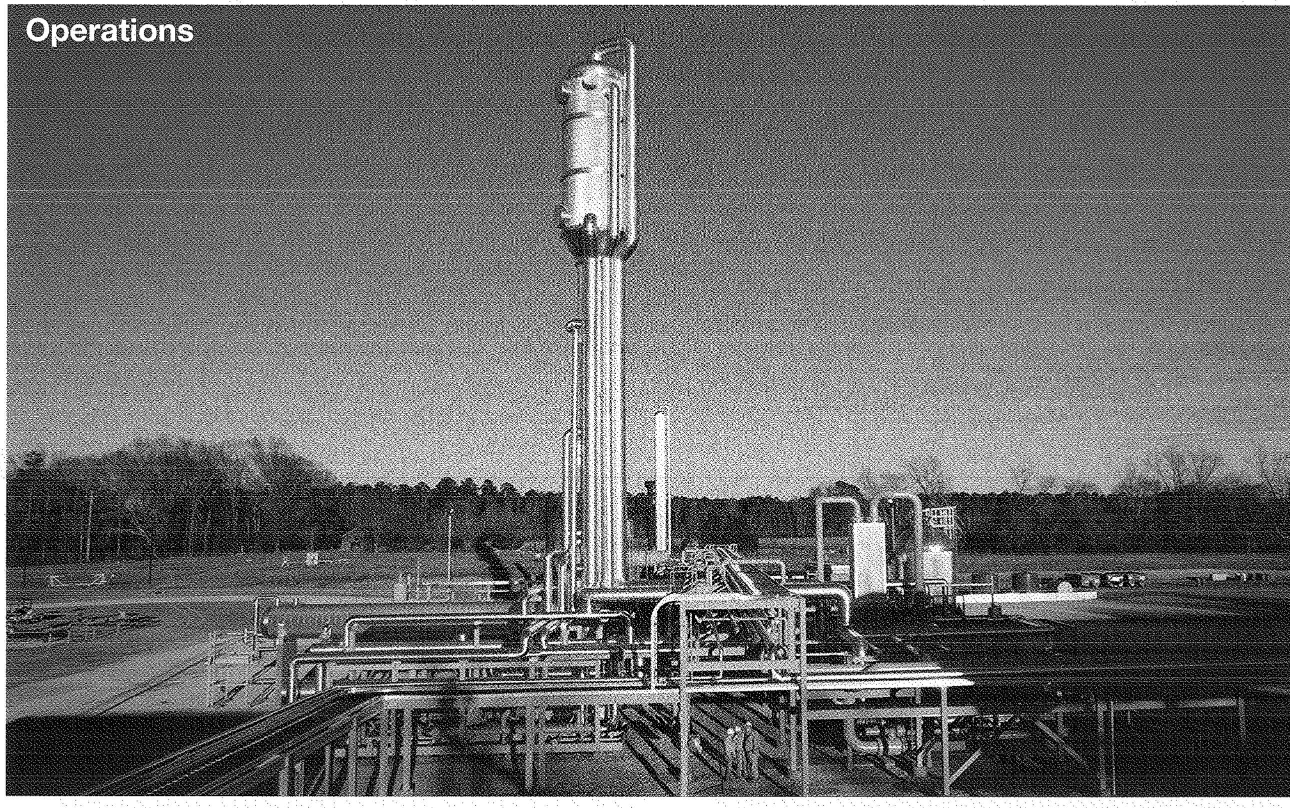
We have a results-oriented team and a strong track record of meeting our objectives. I firmly believe that we have the plan and capabilities to meet the challenges of the current market. We will continue to focus on long-term value for our unitholders through balancing the critical priorities of quality customer service, operational execution, and balance sheet strength.

Thank you for your continued support.

Frank M. Semple
Chairman, President and Chief Executive Officer
April 15, 2009

*DCF and Adjusted EBITDA are non-GAAP financial measures. Please see the Form 8-K we filed on April 23, 2009, for our calculations of DCF and Adjusted EBITDA, along with the corresponding reconciliations to net income, and management's reasons for including such financial measures in this Annual Report. Please refer to the footnotes on the inside front cover of this annual report for disclosures regarding non-GAAP financial measures.

Operations



Operations Overview

We have a significant presence in prolific natural gas producing basins throughout the United States, including the Anadarko, Appalachian, 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 operational success in 2008 resulted from our continued commitment to exceptional customer service, efficient project management practices, and a recognized expertise in midstream gas operations.

We have three geographically based operating segments: the Southwest, the Northeast, and the Gulf Coast. Our assets and operations in each of these segments are summarized below.

Southwest Segment

The Southwest segment is engaged in the gathering, processing, and transmission of natural gas and consists of three operating areas: East Texas, Oklahoma, and Other Southwest. Our assets include 15 natural gas gathering systems with over 1.5 billion cubic feet per day of capacity, seven natural gas processing plants, and four intrastate gas pipelines. In 2008, the Southwest segment contributed 61 percent of revenue and 59 percent of 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 the largest onshore natural gas fields in Texas. Producing formations in Panola County consist of the Cotton Valley, Haynesville Shale, Pettit, and Travis Peak formations, which together form one of the largest natural gas producing regions in the United States.

We further expanded the East Texas gathering system capacity in 2008 from 440 million cubic feet per day (MMcf/d) to 500 MMcf/d. Currently, we gather approximately 470 MMcf/d of natural gas in East Texas, an increase of more than 90 percent since the acquisition of the gathering assets in 2004. In 2008, we also increased the processing capacity at the Carthage facility from 200 MMcf/d to 280 MMcf/d in order to accommodate increased gas volumes from our long-term agreements. The Carthage plant currently processes approximately 240 MMcf/d. Future expansions to the gathering and processing capacity may occur to accommodate new and existing customers' planned drilling programs.

Oklahoma

We operate in two distinct locations in Oklahoma, 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, as well as the Granite Wash gathering system in the Texas Panhandle. The Foss Lake gathering system has a capacity of 130 MMcf/d, and we currently gather approximately 95 MMcf/d. In 2008, we expanded the capacity of the Arapaho processing plant from 100 MMcf/d to 160 MMcf/d. We are currently processing at capacity and are evaluating additional plant expansion opportunities.

In August 2008, we entered into a long-term gathering and processing agreement with Newfield Exploration to gather and process their gas located in the Granite Wash area of the Texas Panhandle. In November 2008, we completed construction of a 60-mile pipeline to connect the acquired Newfield assets to our Foss Lake system and Arapaho processing plant. Our gathering assets in the Granite Wash area have a capacity of 120 MMcf/d, and we currently gather approximately 100 MMcf/d. Future expansions to the gathering and processing capacity in the Granite Wash area may occur to accommodate our customers' planned drilling programs.

In addition to our assets in western Oklahoma, we operate a 500 MMcf/d gathering system located in southeast Oklahoma, which serves our producer customers in the emerging Woodford Shale play in the Arkoma Basin. Through a series of expansions and acquisitions, our throughput volumes in southeast Oklahoma have increased over 130 percent from 180 MMcf/d in 2007 to 425 MMcf/d currently.

As part of our continuing expansion of the Woodford gathering system, in July 2008 we acquired a subsidiary of PetroQuest Energy, which owns natural gas gathering assets located primarily in Pittsburg County in southeast Oklahoma. These gathering systems—situated adjacent to our existing Woodford Shale operations—currently support approximately 50 MMcf/d of natural gas production.

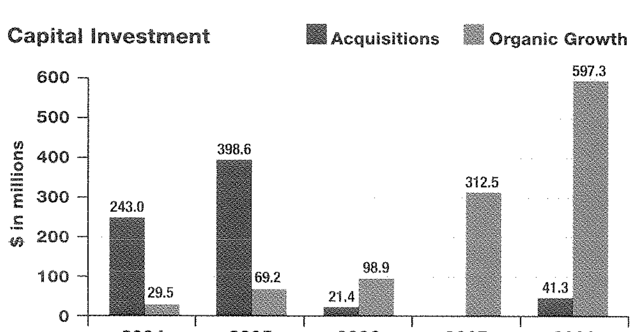
In mid-2008, we acquired an interest in Centrahoma Processing LLC, which owns two gas plants in the Arkoma Basin with a total capacity of 100 MMcf/d, in order to support customers' processing needs.

We announced the construction of the Arkoma Connector Pipeline in January 2008, which will provide additional outlets for producers in the Woodford Shale as gas volumes continue to increase. In December 2008, the Federal Energy Regulatory Commission granted us permission to commence construction of the pipeline, and we expect to complete construction in the first half of 2009. The approximate 640 MMcf/d interstate pipeline will connect our Woodford Shale gathering system to the Midcontinent Express Pipeline and the Gulf Crossing Pipeline at Bennington, Oklahoma. We have executed agreements with certain producers to provide transportation capacity in excess of 600 MMcf/d on the Arkoma Connector Pipeline.

We expect to further expand our gathering assets in the Woodford Shale over the next several years to accommodate anticipated growth.

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. The Appleby system has a total gathering capacity of 85 MMcf/d, which has increased from 20 MMcf/d when we purchased the system in 2003. Currently we gather approximately 60 MMcf/d at Appleby. In addition, we own four intrastate gas pipelines in Texas and New Mexico, which serve utility and industrial customers.



Operations

Northeast Segment

The Northeast segment is engaged in gas processing and fractionation, natural gas liquids transportation, propane storage, and marketing in the Appalachian Basin – including the Marcellus Shale – as well as crude oil transportation and natural gas gathering in Michigan. The Northeast segment generated 30 percent of revenue and 20 percent of net operating margin in 2008.

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 Appalachian Basin since 1988 and continue to be the largest gas processor in the region. Our Appalachian assets include the Boldman, Cobb, Kenova, and Kermit natural gas processing plants, the Siloam fractionation and propane storage facility, and an NGL pipeline.

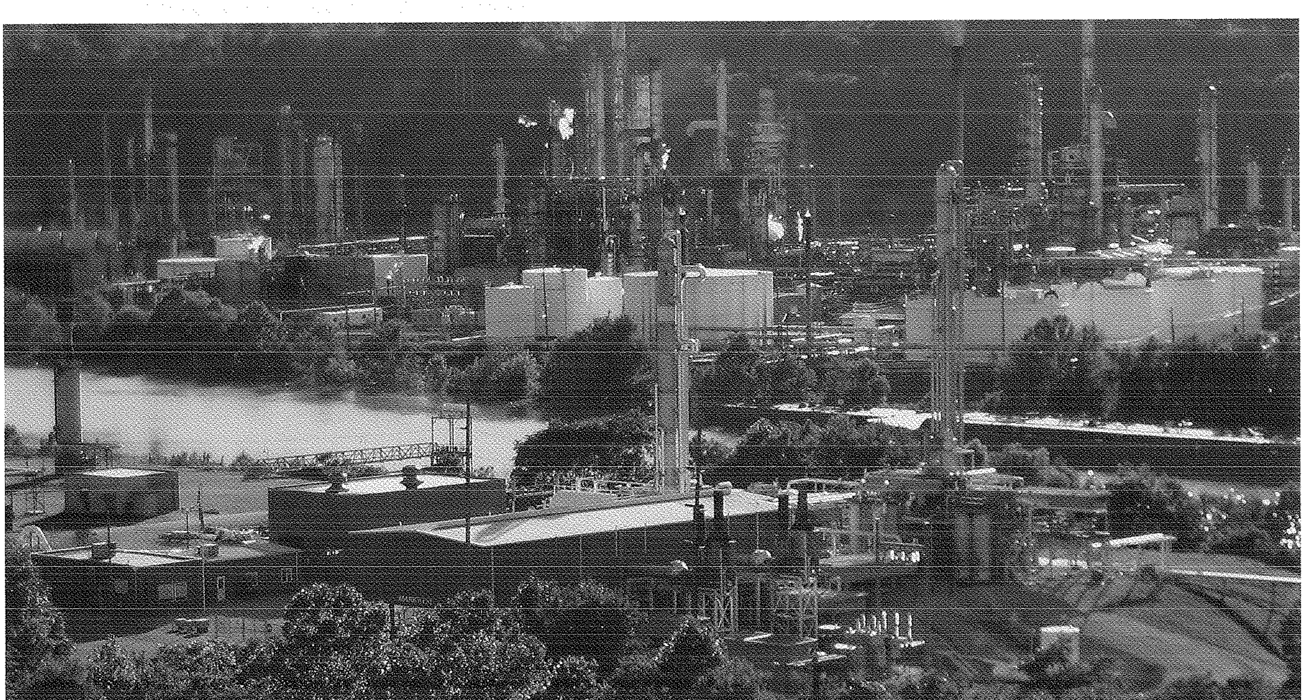
We recently expanded several of our plants in the Appalachian region. The expansion included replacing the existing Cobb processing plant with a cryogenic processing facility and modifying the Kenova processing plant to improve propane recovery. The Cobb expansion increased NGL production capacity from 30,000 gallons per day (Gal/d) to approximately 70,000 Gal/d while the Kenova modification increased propane production by approximately 10,000 Gal/d. Our Appalachian assets have processing capacity of 300 MMcf/d, and we currently process approximately 205 MMcf/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, we also expanded the fractionation capacity at Siloam from 600,000 Gal/d to 900,000 Gal/d where we currently fractionate approximately 650,000 Gal/d. We completed the expansion of the Siloam facility in the first quarter of 2009.

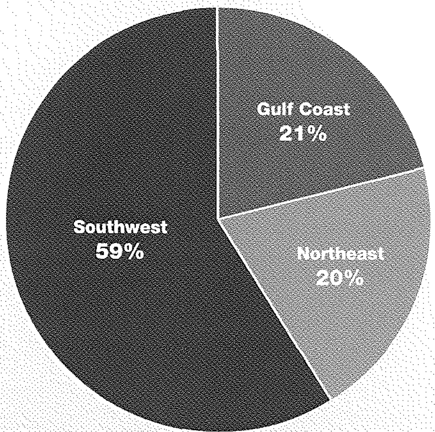
Marcellus Shale

The Marcellus Shale is a newly emerging natural gas formation extending throughout much of the Appalachian Basin. In June 2008, we announced a long-term agreement with Range Resources Corporation to construct and operate natural gas gathering pipelines and processing facilities associated with Range's significant Marcellus Shale acreage in the Appalachian Basin. Range has been operating in the area since 2004 and is a leader in the development of the Marcellus Shale. In October 2008, we began operations utilizing an interim 30 MMcf/d processing facility and we currently process approximately 35 MMcf/d.

In 2008, we announced our intention to jointly develop and expand several natural gas gathering and processing projects with Columbia Gas, a division of NiSource Inc., to support increased production volumes in northern and central West Virginia and western Pennsylvania. Several existing Columbia pipelines in Washington and Greene counties in Pennsylvania and Marshall and Wetzel counties in West Virginia are available to serve



Net Operating Margin by Segment



as the backbone of the gathering system connecting with a proposed processing plant at Majorsville.

In February 2009, we entered a joint venture partnership with Midstream & Resources (M&R) whereby we contributed all of our Marcellus Shale assets to the joint venture. The joint venture is owned 60 percent by MarkWest and 40 percent by M&R, and we operate the joint venture. By early 2010, we expect to have gathering and compression capacity of 120 MMcf/d as well as processing capacity of 270 MMcf/d primarily stemming from three permanent cryogenic processing facilities: a 30 MMcf/d processing facility and two 120 MMcf/d processing facilities.

Michigan

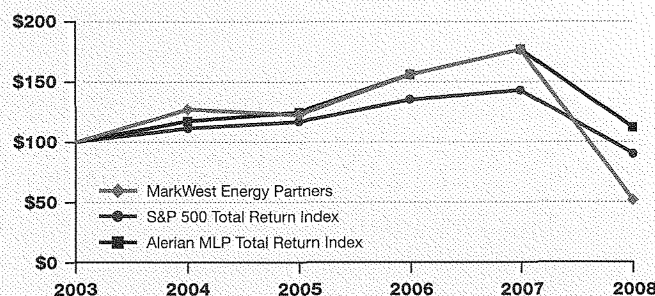
We own and operate a crude oil pipeline in Michigan, which is subject to regulation by the Federal Energy Regulatory Commission. The pipeline is the largest crude oil gathering pipeline in Michigan and supports the production of our producer customers. The pipeline interconnects with a large downstream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

Gulf Coast Segment

The Gulf Coast segment consists of a 50 percent ownership in the Starfish Pipeline Company and the Javelina gas processing and fractionation facility in Corpus Christi, Texas. Acquired in early 2005, Starfish provides gas gathering and transportation services in the Gulf of Mexico and southwestern Louisiana. Starfish is accounted for using the equity method of accounting, and therefore the reported segment income for the Gulf Coast segment is derived entirely from our Javelina operations. In 2008, the Gulf Coast segment contributed 9 percent of revenue and 21 percent of net operating margin.

Javelina treats, processes, and fractionates off-gas from six local refineries. Javelina has a processing capacity of 142 MMcf/d and we currently process approximately 120 MMcf/d. We are constructing a steam methane reformer (SMR) facility at Javelina to meet our refinery customers' requirements for high-purity hydrogen, and we expect to commence delivery in early 2010. Once operational, the SMR facility, combined with the existing facilities at the Javelina plant, will have the capacity to produce in excess of 50 MMcf/d of high-purity hydrogen. The SMR facility is anchored by a long-term fee-based supply agreement.

Performance Graph
(Assumes $100 Investment on 12/31/03)



Source: Bloomberg

Map of Operations

Southwest Segment

East Texas
- 500 MMcf/d gathering capacity
- 280 MMcf/d processing plant

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

Western Oklahoma
- 275 MMcf/d gathering capacity
- 160 MMcf/d processing plant

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

Gulf Coast Segment

Javelina
- Refinery off-gas processing, fractionation, and transportation facilities

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

Northeast Segment

Appalachia
- Five processing plants with combined 330 MMcf/d processing capacity
- 900K Gal/d NGL fractionation facility
- 11 million gallon NGL storage facility
- 80-mile NGL pipeline
- Joint venture with Midstream & Resources to develop midstream infrastructure in the Marcellus Shale

Michigan
- 250-mile intrastate crude pipeline
- 90-mile gas gathering pipeline

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, 2008

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the transition period from to

Commission File Number 001-31239

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

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

1515 Arapahoe Street, Tower 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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2008 was approximately $1.7 billion.

As of February 23, 2009, the number of the registrant's common units were 56,893,885.

DOCUMENTS INCORPORATED BY REFERENCE:

The information required by Part III of this Report, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement relating to the Annual Meeting of Unitholders to be held in 2009, 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, 2008.

As explained further in Part I, Item 1. Business, on February 21, 2008, MarkWest Energy Partners, L.P. completed its plan of redemption and merger (the "Merger") with MarkWest Hydrocarbon, Inc. (the "Corporation") and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership, pursuant to which the Corporation was merged into the Partnership. The Merger was considered a downstream merger whereby the Corporation was 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 was accounted for in the Corporation's consolidated financial statements as an acquisition of non-controlling interest using the purchase method of accounting. As a result, the historical and comparative consolidated financial statements of the surviving legal entity are those of the Corporation, the accounting acquirer, rather than those of the Partnership, the legal acquirer. Under the Merger, the shareholders of the Corporation exchanged each share of Corporation common stock for consideration equal to 1.9051 Partnership common units (the "Exchange Ratio"). All historical unit and per unit data has been adjusted to reflect the Exchange Ratio to give effect of the Merger.

Glossary of Terms

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

Bbl/d	barrels per day
Btu	one British thermal unit, an energy measurement
Gal/d	gallons per day
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
Net operating margin (a non-GAAP financial measure)	revenues less purchased product costs
NGL	natural gas liquid, such as propane, butane and natural gasoline
N/A	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.

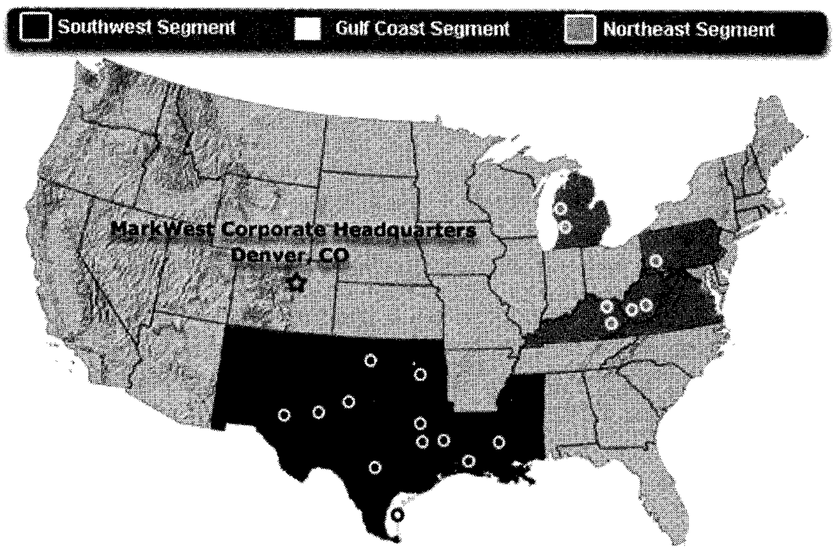
These forward-looking statements are made based upon management's expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could 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 on January 25, 2002. We are a master limited partnership engaged in the gathering, compressing, treating, processing and transportation of natural gas; the transportation, fractionation, storage, and marketing of NGLs; and the gathering and transportation of crude oil. We conduct our operations in three geographical operating segments: the Southwest, the Northeast, and the Gulf Coast. A map representing the location of the assets that comprise our segments is set forth below. Additional maps detailing the individual assets can be found on our Internet website, *www.markwest.com*. For more information on these segments, see the *Our Operating Segments* discussion below.



The following table summarizes the operating performance for each segment for the year ended December 31, 2008 (amounts in thousands). For further discussion of our segments, see Note 23 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

	Southwest	Northeast	Gulf Coast	Total
Revenue	$652,365	$316,255	$92,042	$1,060,662
Operating expenses:				
Purchased product costs	387,516	228,386	—	615,902
Facility expenses	62,369	22,875	17,368	102,612
Operating income before items not allocated to segments	$202,480	$ 64,994	$74,674	$ 342,148

Recent Developments

Merger

On February 21, 2008, the Partnership and the Corporation completed the Merger by which the Corporation became a wholly owned subsidiary of the Partnership. In connection with the Merger, the 2% economic interest and incentive distribution rights in the Partnership owned by MarkWest Energy GP, L.L.C. (the "General Partner") and the Partnership common units owned by the

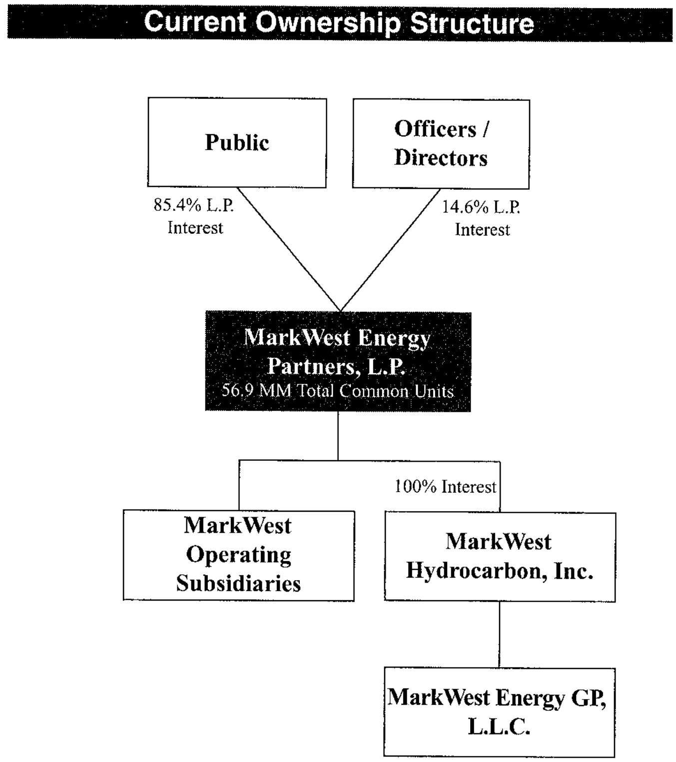
Corporation were exchanged for Partnership Class A units. In a separate transaction completed simultaneously with the closing of the Merger, the Partnership acquired 100% of the Class B membership interests in the General Partner that had been held by current and former management and certain directors of the Corporation and the General Partner. The organizational structure resulting from this series of transactions is shown in the chart below. Please refer to Note 3 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details about the Merger.

The Corporation and the General Partner collectively own 22.6 million Class A units of the Partnership that were received in the Merger in exchange for the incentive distribution rights and the 2% economic interest in the Partnership held by the General Partner and common units held by the Corporation prior to the Merger. The Class A units represent a 29% interest in the Partnership as of February 23, 2009 as follows (units in millions):

	Units	%
Class A units	22.6	28%
Common units	56.9	72%
Total units	79.5	100%

Class A units represent limited partner interests in the Partnership and have identical rights and obligations of the Partnership common units except that Class A units (i) do not have the right to vote on, approve or disapprove, or otherwise consent to or not consent to any matter (including mergers, share exchanges and similar statutory authorizations) except as otherwise required by any non-waivable provision of law and (ii) do not share in any cash and cash equivalents on hand, income, gains, losses, deductions and credits that are derived from or attributable to the Partnership's ownership of, or sale or disposition of, the shares of MarkWest Hydrocarbon common stock. The transaction structure involving the issuance of the Class A units in exchange for Partnership interests owned by the Corporation and the General Partner was adopted partially for tax purposes. The Class A units held by MarkWest Hydrocarbon and the General Partner are not treated as outstanding common units in the accompanying Consolidated Balance Sheets pursuant to Accounting Research Bulletin No. 51, *Consolidated Financial Statements*.

The ownership percentages in the graphic depicted below reflect the Partnership structure from the basis of the consolidated financial statements with the Class A units eliminated.



The primary benefit realized from the Merger is the elimination of the incentive distribution rights which represented the right to receive an increasing percentage of quarterly distributions of available cash after a minimum quarterly distribution and certain target distribution levels had been achieved. The elimination of incentive distribution rights substantially lowers our cost of equity capital and increases the cash available to be distributed to our common unitholders. This enhances our ability to compete for new acquisitions and improves the returns to our unitholders on all future expansion projects. Another benefit of the Merger is that the Partnership is now able to distribute available cash from the Corporation. The Merger has also resulted in cost savings from the elimination of duplicative services required to maintain two publicly traded companies.

Liberty Joint Venture

On January 22, 2009, we entered into an agreement to form a joint venture with an affiliate of NGP Midstream & Resources, L.P. ("M&R"), a private equity firm focused on investments in selected areas of the energy infrastructure and natural resources sectors. The agreement was executed on February 27, 2009. The joint venture entity, MarkWest Liberty Midstream & Resources, L.L.C. ("Liberty Midstream") operates in the natural gas midstream business in and around the Marcellus Shale in Pennsylvania and certain counties in West Virginia and Ohio. Liberty Midstream operations will include providing gathering and processing services under an existing agreement with an affiliate of Range Resources Corporation ("Range"). For further discussion of the agreement with Range, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—*Matters Impacting Future Results* included in this Annual Report on Form 10-K. Under the terms of the joint venture agreement, we contributed our existing Marcellus Shale natural gas gathering and processing assets to Liberty Midstream, in exchange for a 60% ownership interest. The estimated value of the contributed assets is approximately $107.0 million. M&R will make cash contributions of

$200.0 million during 2009 in exchange for a 40% ownership interest. We will make additional capital contributions to Liberty Midstream through a combination of reinvestment of cash distributions received from Liberty Midstream and additional cash capital contributions until the aggregate amounts of capital contributed by us and M&R are in the ratio of 60% and 40%, respectively. Liberty Midstream is managed by a Board of Managers, which currently consists of three managers designated by us and two managers designated by M&R. We will serve as the operator of Liberty Midstream and will provide employees through a services agreement that was entered into at the closing of the joint venture transaction. The joint venture will allow us to achieve our long-term objectives in the Marcellus Shale while significantly reducing capital requirements in 2009, which is a critical component of our balance sheet and liquidity objectives.

Amendment to Partnership Credit Agreement

On January 28, 2009, we also entered into the first amendment to our credit agreement which became effective March 2, 2009. The amendment expands borrowing capacity under the revolving facility by $85.6 million from $350.0 million to $435.6 million, and facilitated the formation of Liberty Midstream. Pursuant to the amendment, the term of the original credit agreement has been reduced by one year and will now be due on February 20, 2012. The accordion feature established under the original credit agreement remains at $200.0 million of uncommitted funds. The amendment increases the interest rate on the outstanding borrowings by 100 basis points and establishes a floor of 2% for the LIBOR rate used to determine the interest rate on LIBOR loans. For further discussion of the amendment to our credit agreement, see Note 26 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

Business Strategy

Our primary business strategy is to provide top-tier midstream service by developing high-quality strategically located assets in the United States. We plan to accomplish this through the following:

- *Maintaining our financial flexibility.* During 2008, we issued approximately $171.4 million of equity and $500.0 million of long-term debt. Our goal is to maintain a capital structure with approximately equal amounts of debt and equity on a long-term basis. We also consider the use of alternative financing strategies such as entering into joint venture arrangements and the sale of selected assets that are not a core component of our long-term objectives. Our credit facility, our ability to issue additional partnership units, strategic joint venture arrangements, and the sale of non-strategic assets should provide us with the financial flexibility to facilitate the execution of our business strategy.
- *Expanding operations through organic growth projects.* By expanding our existing infrastructure and customer relationships, we intend to continue growing in our primary areas of operation to meet the anticipated demand for additional midstream services. During 2008, we spent approximately $638.6 million of growth capital to expand several of our gathering and processing operations, including the acquisition of PQ Gathering Assets, L.L.C. and our equity investment in Centrahoma Processing, L.L.C. In our Southwest segment, projects included the expansion of our Woodford gathering system in the Arkoma Basin and the start of construction of an interstate pipeline in Southeastern Oklahoma, ongoing compressor expansions in East Texas, and the completion of a 60 MMcf/d processing facility in Western Oklahoma. Other projects included the development of operations in the Marcellus Shale area and the expansion of our processing and fractionation facilities in the Northeast segment.
- *Increasing utilization of our facilities.* We seek to increase the utilization of our existing facilities by providing additional services to our existing customers, and by establishing relationships with new customers. Increased drilling activity in our core areas of operation, particularly within the

Southwest and Northeast, should also produce increasing natural gas and crude oil supplies, and a corresponding increase in utilization of our transportation, gathering, processing and fractionation facilities. We also continue to develop additional capacity at several of our facilities, which enables us to increase throughput with minimal incremental costs.

- *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. We engage 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. We 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. We monitor these activities through enforcement of our risk management policy. Please refer to Item 7A. Quantitative and Qualitative Disclosures About Market Risk—*Commodity Price Risk.*
- *Expanding operations through strategic acquisitions.* We intend to continue pursuing strategic acquisitions of assets and businesses in our existing areas of operation that leverage our current asset base, personnel and customer relationships. We may also seek to acquire assets in certain regions outside of our current areas of operation. We believe the elimination of the incentive distribution rights in connection with the Merger, positions us to compete more effectively for future transactions.

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

- *Leading position and continued expansion 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 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 2008, we completed an upgrade of our Kenova processing plant and expect to complete the expansion of our Cobb facility in the first half of 2009. The expansion of our Siloam fractionation facility is also expected to be completed in the first quarter of 2009. During 2008, we also acquired and began constructing gathering and processing facilities in the Marcellus Shale area of the Appalachian Basin and continue to expand our Marcellus operations under the joint venture arrangement described above in *Recent Developments.*
- *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 agreement with Newfield Exploration Mid-Continent Inc. ("Newfield") by building the largest gathering system to date in the newly emerging Woodford Shale play in Southeast 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 U.S. 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;

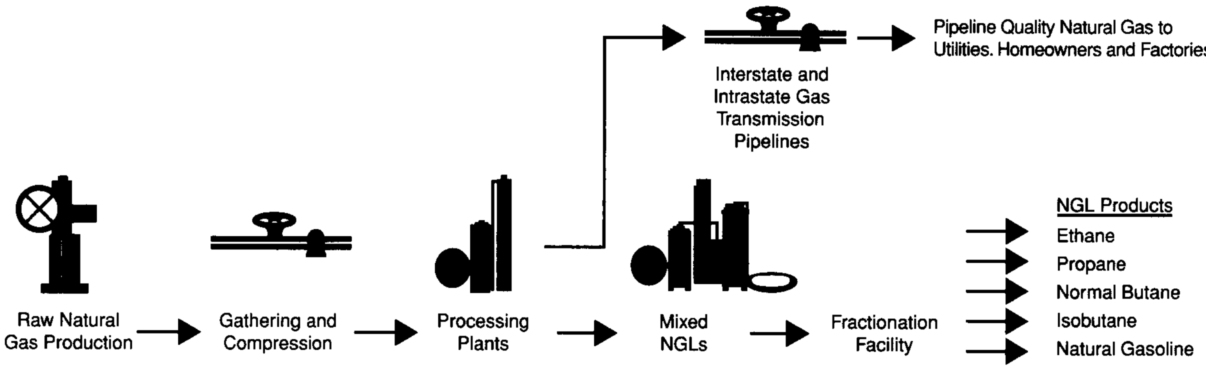
- access to a significant reserve or customer base with a stable or growing production profile;
- ample opportunities for long-term continued organic growth;
- ready access to markets; and
- close proximity to other acquisition or expansion opportunities.

  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 plants are located in the Anadarko Basin in Oklahoma and are connected to the Granite Wash area in the Texas panhandle. Additionally, as mentioned above, our Woodford gathering system is located in the rapidly developing Woodford Shale reservoir. Our gathering systems are relatively new and provide producers with low-pressure and fuel-efficient service, a significant competitive advantage for us over many competing gathering systems in those areas. We believe this competitive advantage is evidenced by our growing throughput volumes in our East Texas, Appleby, Woodford, and Western Oklahoma 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 79% of our current gathering volumes are under contract for longer than five years as of December 31, 2008. Due to new contracts signed in August 2008, approximately 47% of our current daily throughput in the Western Oklahoma gathering system and Arapaho processing plants are subject to contracts with remaining terms of approximately ten years. Approximately 98% of our throughput in the Woodford gathering system is subject to contracts with remaining terms of more than five years. Also in the Southwest segment, two of our lateral pipelines operate under fixed-fee contracts for the transmission of natural gas that expire in approximately 12 and 20 years, respectively. In Appalachia, our natural gas processing and NGL fractionation contracts with remaining terms of more than six years account for approximately 86% of our volumes.
- *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 eleven acquisitions.

Industry Overview

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

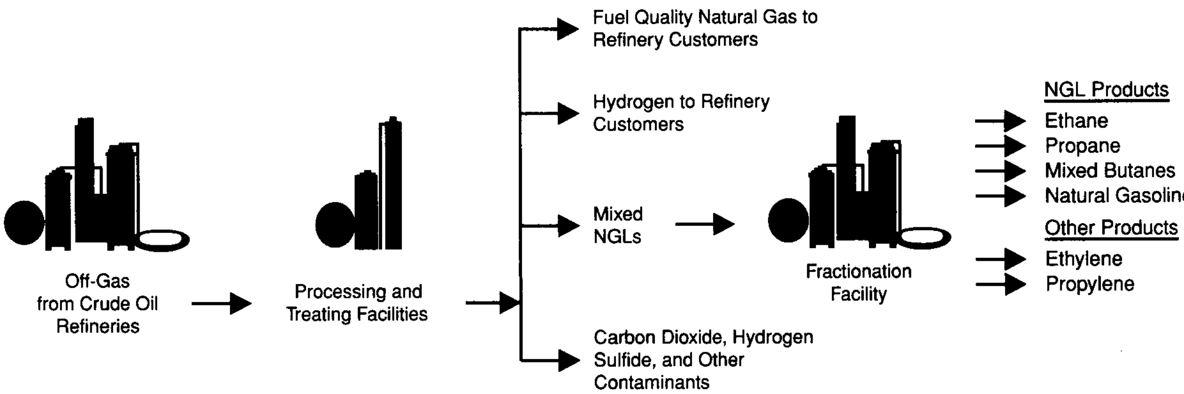


The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once completed, the well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems, that collect natural 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.

We also provide processing and fractionation services to crude oil refineries in the Corpus Christi, Texas, area through our 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.

Five basic NGL products and their typical uses are:

- *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.

Our Operating Segments

We conduct our operations in three geographical operating segments: the Southwest, the Northeast and the Gulf Coast. Our assets and operations in each of these segments are described below.

Southwest Segment

- *East Texas.* Our East Texas system consists of natural gas gathering pipelines, centralized compressor stations, a natural gas processing facility and an NGL pipeline. The East Texas system is located in Panola, Harrison and Rusk Counties and services the Carthage Field. Producing formations in Panola County consist of the Cotton Valley, Pettit and Travis Peak formations, which collectively form one of the largest natural gas producing regions in the United States. For natural gas that is processed in this region, we purchase the NGLs from the producers primarily under percent-of-proceeds arrangements, or we transport volumes for a fee. Approximately 82% of our natural gas volumes in the East Texas System result from contracts with five producers. The resulting NGLs, condensate sold and fee-based revenue from these five producers make up approximately 80% of our revenues in the East Texas region. We sell substantially all of the purchased and retained NGLs produced at our East Texas processing facility to Targa Resources Partners, L.P. ("Targa") under a long-term contract. Such sales represent approximately 22% of the Partnership's consolidated revenue in 2008. For the year ended December 31, 2008, the contract contributed 4% to net operating margin, (a non-GAAP measure, see *Our Contracts* below for discussion and reconciliation of net operating margin). We do not consider the Targa contract a material contract when considering its contribution to net operating margin because the NGLs are sold at a current market price adjusted for certain fees and there are other alternative markets to sell NGLs near our system. The original term of the Targa agreement expires in December 2015.
- *Oklahoma.* We own the Foss Lake natural gas gathering system and the Arapaho I and II natural gas processing plants, all 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. Under a new agreement executed in 2008 with Newfield, we constructed a 60-mile pipeline from our Foss Lake system to the Granite Wash formation in the Texas panhandle and plan to build new gathering and compression infrastructure in the area. We also own the Grimes gathering system, which is located in Roger Mills and Beckham Counties in Western Oklahoma. In addition, we own a natural gas gathering system in the Woodford Shale play in the Arkoma Basin of Southeast Oklahoma. During 2008, we acquired a subsidiary of PetroQuest Energy, L.L.C. ("PetroQuest") that owns natural gas gathering assets located primarily in Pittsburg County in Southeast Oklahoma as part of our expansion of the Woodford gathering system. Approximately 78% of our Oklahoma volumes result from contracts with three producers. Approximately 90% of our current volumes associated with our existing Oklahoma assets are derived from gathering contracts and approximately 10% are derived from purchase agreements. The Oklahoma region has one customer to which we sell NGLs which account for a significant portion of the Southwest segment revenue, but sales to this customer do not account for a significant portion of the Partnership's consolidated revenue in 2008.
- *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 area does not have any customers which we consider to be significant to the Southwest segment revenue or the Partnership's consolidated revenue.

Northeast Segment

- *Appalachia.* We are the largest processor 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, the Siloam NGL fractionation plant and two caverns for storing propane. The Northeast segment operations include MarkWest Hydrocarbon, Inc. which is a taxable corporation. The Corporation pays tax on its income or loss and its share of the Partnership's income or loss resulting from its ownership of the Partnership's Class A units. During 2008 we constructed natural gas gathering systems and processing facilities associated with the Marcellus Shale acreage controlled by Range. As noted above in *Recent Developments*, on January 22, 2009 we entered into an agreement to contribute our assets in the Marcellus Shale area to a joint venture with M&R. We will maintain a 60% interest in the operating interest in the assets. The Appalachia area has two customers which account for a significant portion of the Northeast segment revenue, but neither customer accounts 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 in Michigan. The Michigan operations do not have any single customer which is considered to be significant to the Northeast segment revenue.

Gulf Coast Segment

- *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 120 to 130 MMcf/d of inlet gas out of its 142 MMcf/d capacity. No individual customers in the Gulf Coast segment account for a significant portion of the Partnership's consolidated revenue.

We own a 50% non-operating membership interest in Starfish Pipeline Company, L.L.C. ("Starfish"), whose assets are located in the Gulf of Mexico and Southwestern Louisiana. The Starfish interest is a joint venture with Enbridge Offshore Pipelines L.L.C., which is accounted for using the equity method; the financial results for Starfish are included in *Earnings from unconsolidated affiliates* and are not included in our segment 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.

We own a 40% non-operating membership interest in Centrahoma Processing, L.L.C. ("Centrahoma"), which is accounted for under the equity method. Centrahoma owns certain processing plants in the Arkoma Basin. In addition, we signed agreements to dedicate our processing rights in certain acreage in the Woodford Shale play to Centrahoma through March 1, 2018. The financial results for Centrahoma are included in *Earnings from unconsolidated affiliates* and are not included in our segment results.

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 segment, for the year ended December 31, 2008:

	Southwest	Northeast	Gulf Coast	Total
Revenue	61%	30%	9%	100%
Net operating margin	59%	20%	21%	100%

For further financial information regarding our segments, 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.

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, transportation and processing; NGL transportation, fractionation, marketing and storage; and crude oil gathering and transportation. We enter into a variety of contract types. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described below. We provide services under the following different types of arrangements:

- *Fee-based arrangements:* Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, processing and 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. In other cases, instead of remitting cash payments to the producer, we deliver an agreed-upon percentage of the residue gas and NGLs to the producer and sell the volumes we keep to third parties at market prices. The percentage of volumes that we retain can be either fixed or variable. Generally, under these types of arrangements our revenues and 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. Due to current market and financial conditions, we have seen decreases in natural gas, condensate and NGL prices, and it is uncertain if these declines will continue in the future.

- *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. Certain keep-whole arrangements also have provisions that require us to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio. 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 that we operate our gathering systems more or less efficiently than specified per contract allowance, we will retain the benefit or loss for our own account.

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

As of December 31, 2008, our primary exposure to keep-whole contracts was limited to our Appalachian, Western Oklahoma (Arapaho), East Texas (Carthage), and Woodford processing agreements.

- As a result of the Merger with MarkWest Hydrocarbon and the acquisition of its NGL marketing business, our exposure to keep-whole contracts has increased and has resulted in an increase to our exposure to natural gas and NGL volatility in Appalachia. During 2008, approximately 72% of the NGLs sold from Appalachia relate to keep-whole contracts.

- At the inlets to the Arapaho plants, natural gas meets the downstream pipeline specification; however, we have the option of extracting NGLs when the processing margin environment is favorable. All of our gas gathering contracts in Western Oklahoma are keep-whole, but some of the contracts include additional fees to cover plant operating costs, fuel costs and shrinkage costs in a low-processing margin environment. Our keep-whole contract exposure is partially mitigated due to our ability to operate the Arapaho plants in several recovery modes.

- Approximately 8% of the gas processed in East Texas for producers was processed under keep-whole terms for the year ended December 31, 2008.

- Approximately 40 MMcf/d of the gas in the Woodford system is rich with NGLs and is processed under keep-whole contracts. Our keep-whole contract exposure is partially mitigated by our ability to operate in several recovery modes.

- Our keep-whole exposure in all areas was partially offset by the settlement margin related to certain gathering and compression arrangements. The excess natural gas retained under these arrangements reduced the amount of replacement natural gas purchases required to keep our producers whole on an MMBtu basis, thereby creating a partial natural hedge. We also have an active commodity risk management program in place to reduce the impacts of changing NGL and natural gas prices and our keep-whole exposure.

Management evaluates contract performance on the basis of net operating margin (a non-GAAP financial measure), which is defined as revenue, excluding any derivative gain (loss), less purchased product costs, excluding any derivative gain (loss). These charges have been excluded for the purpose of enhancing the understanding by both management and investors of the underlying baseline operating performance of our contractual arrangements, which management uses to evaluate our financial performance for purposes of planning and forecasting. Net operating margin does not have any standardized definition and therefore is unlikely to be comparable to similar measures presented by other reporting companies. Net operating margin results should not be evaluated in isolation of, or as a substitute for, our financial results prepared in accordance with GAAP. Our 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,		
	2008	2007	2006
Revenue	$1,060,662	$845,727	$829,298
Purchased product costs	615,902	487,892	560,597
Net operating margin	444,760	357,835	268,701
Facility expenses	103,682	70,863	57,403
Total derivative (gain) loss	(254,813)	175,148	(4,694)
Selling, general and administrative expenses	68,975	72,484	63,360
Depreciation	67,480	41,281	31,010
Amortization of intangible assets	38,483	16,672	16,047
Loss (gain) on disposal of property, plant and equipment	178	7,743	(322)
Accretion of asset retirement obligations	129	114	102
Impairment of goodwill and long-lived assets	36,351	356	—
Income (loss) from operations	$ 384,295	$ (26,826)	$105,795

The following table is prepared as if we did not have an active commodity risk management program in place. For further discussion of how we have reduced the downside volatility to the portion of our net operating margin that is not fee-based, see Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk of this Form 10-K. For the year ended December 31, 2008, we calculated the following approximate percentages of our revenue and net operating margin from the following types of contracts:

	Fee-Based	Percent-of-Proceeds(1)	Percent-of-Index(2)	Keep-Whole(3)	Total
Revenue	11%	34%	18%	37%	100%
Net operating margin	25%	34%	8%	33%	100%

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

(2) Includes settlement margin 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.

While the percentages in the table above accurately reflect the percentages by contract type, we manage our business by taking into account the partial offset of short natural gas positions by long positions primarily in our Southwest segment, required levels of operational flexibility and the fact that our hedge plan is implemented on this basis. When the partial offset of our natural gas positions is considered, 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 55%, 0% and 20%, respectively.

Competition

In each of our operating segments, 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 that our customer focus in all segments, demonstrated by our ability to offer an integrated package of services and our flexibility in considering various types of contractual arrangements allows us to compete more effectively. Additionally in our Gulf Coast segment, the strategic location of our assets and the long-term nature of our contracts provide a significant competitive advantage. In the Southwest segment our major gathering systems are relatively new and provide producers with low-pressure and fuel-efficient service, which differentiates us from many competing gathering systems in those areas. In the Northeast segment, our existing presence in the Appalachian Basin in addition to our strategic gathering and processing agreements with Range provide a competitive advantage to participate in the further development of the Marcellus Shale.

Acquisitions

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 in May 2002, we have completed eleven acquisitions (excluding the Merger) for an aggregate purchase price of approximately $875 million, net of working capital. The acquisitions were individually accounted for as business combinations or equity investments. Summary information regarding our 2008, 2007 and 2006 acquisitions is presented below (consideration in millions):

Name	Assets	Location	Consideration	Closing Date
PQ Gathering Assets, L.L.C.(1)	Gathering systems	Oklahoma	$41.3	July 31, 2008
Centrahoma Processing, L.L.C.(2)	Gas processing facility	Oklahoma	23.6	March 1, 2008 and May 9, 2008
Santa Fe	Grimes gathering system	Oklahoma	15.0	December 29, 2006

(1) Includes a 50% operating interest in Wirth Gathering, a general partnership (see Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

(2) Represents a 40% non-controlling interest (see Note 12 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

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, contingent on availability of financing. We may also seek to selectively acquire assets in regions outside our current areas of operation. We believe the elimination of the incentive distribution rights as a result of the Merger positions us to compete more effectively for acquisitions.

Seasonality

Our business is affected by seasonal fluctuations in 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. Our Northeast segment is particularly impacted by seasonality. In the Appalachia area, we store a portion of the propane that is produced in the summer to be sold in the winter months. As a result of our seasonality, we generally expect the sales volumes in our Northeast segment to be higher in the first quarter and fourth quarter.

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, which is currently being constructed, and our Michigan Crude Pipeline and related assets are subject to regulation by the FERC. In addition, we own a 50% non-operating membership interest in Starfish which has a subsidiary, Stingray Pipeline Company, L.L.C. ("Stingray"), that is subject to FERC regulation. 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 when it is completed. 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.

Rate Cases. On June 30, 2008, Stingray made a rate case filing with the FERC to increase its rates and make several changes to the general terms and conditions set forth in its FERC gas tariff, pursuant to Section 4 of the NGA ("Rate Filing"). Various shippers protested the Rate Filing and on July 30, 2008, the FERC initiated a hearing in the proceeding. At the same time, the FERC asked the parties to submit additional comments regarding Stingray's proposed tariff revisions. The parties submitted additional comments in August 2008 and on November 13, 2008, the FERC issued an order accepting all of the proposed changes, with the exception of Stingray's proposed charge for free water, which the FERC set for hearing. The protesters requested rehearing of this order, which the FERC granted on January 14, 2009. In an effort to settle the outstanding issues in the proceeding, the parties held three informal settlement conferences in January of 2009. On January 27, 2009, Stingray filed a motion to suspend the procedural schedule, stating that the parties had reached an agreement in principle that fully resolved all issues in the proceeding. Stingray stated that a formal Offer of Settlement would be filed within 60 days of an order suspending the procedural schedule. The FERC suspended the procedural schedule on January 30, 2009. On February 3, 2009, Stingray filed a motion to place the settlement rates into effect on an interim basis and on February 11, 2009, the FERC accepted the motion. The settlement rates included an increased rate for Rate Schedules FTS, FTS-2, ITS, and PAL, as well as an event surcharge. Stingray's formal Offer of Settlement will be subject to the certification and approval of the administrative law judge overseeing the proceeding and the FERC.

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 ("2005 EPAct2005 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.

Standards of Conduct. On October 16, 2008, the FERC issued a Final Rule ("Order 717") revising the FERC Standards of Conduct for natural gas and electric transmission providers by eliminating its earlier concept of Energy Affiliates and corporate separation in favor of an employee functional approach. A transmission provider is prohibited from disclosing to a marketing function employee non-public information about the transmission system or a transmission customer. Order 717 also retains the long-standing no-conduit rule, which prohibits a transmission function provider from disclosing non-public information to marketing function employees by using a third party conduit. Additionally, Order 717 requires that a transmission provider provide annual training on the Standards of Conduct to all transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information. This rule became effective November 26, 2008.

Market Transparency Rulemakings. On December 26, 2007, the FERC issued Order No. 704 implementing certain transparency provisions. The order became effective February 4, 2008. The initial report is due May 1, 2009 for calendar year 2008. Subsequent reports are due by May 1 of each year for the previous calendar year. Order 704 will require most, if not all of our natural gas pipelines to report annual volumes of relevant transactions to the FERC. The FERC issued Order 704-A on September 18, 2008. This order generally affirmed the rule, while clarifying what information certain natural gas market participants must report in Form 552. The revisions pertain to the reporting of transactions occurring in calendar year 2008. The first report is due May 1, 2009 and each May 1st thereafter for subsequent calendar years. Order 704-A became effective October 27, 2008.

In addition, on December 21, 2007, the FERC issued a new notice of proposed rulemaking ("December 21 NOPR") proposing to exempt from the daily posting requirements those non-interstate pipelines that (i) flow less than ten million MMBtus of natural gas per year; (ii) fall entirely upstream of a processing plant; and (iii) deliver more than 95% of the natural gas volumes they flow directly to end-users. However, the December 21 NOPR expands the proposal to require that both interstate and non-exempt non-interstate pipelines post daily the capacities of, volumes scheduled at, and actual volumes flowing through, their major receipt and delivery points and mainline segments.

On November 20, 2008, the FERC issued Order 720, which is the final rule regarding the December 21 NOPR. Order 720 established new reporting requirements for interstate and major non-interstate pipelines. A major non-interstate pipeline is defined as a pipeline who delivers annually more than 50 million MMBtu of natural gas measured in average deliveries for the previous three calendar years. Interstate pipelines will be required to post no-notice activity at each receipt and delivery point three days after the day of gas flow. Major non-interstate pipelines will be required to post design capacity, scheduled volumes and available capacity at each receipt or delivery point with a design capacity of 15,000 MMbtus of natural gas per day or greater when gas is scheduled at the point.

The effective date is sixty days from when the final rule is published in the Federal Register for interstate pipelines and one hundred fifty days from publication for major non-interstate pipelines.

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.

FERC Equity Return Allowance. On April 17, 2008, the FERC adopted a new policy under Docket No. PL07-2-000 that will allow master limited partnerships to be included in proxy groups for the purpose of determining rates of return for both interstate natural gas and oil pipelines. The policy statement will govern all future gas and oil rate proceedings involving the establishment of a return on equity, as well as those cases that are currently pending before either the FERC or an administrative law judge. On May 19, 2008, an application for rehearing was filed by The American Public Gas Association. On June 13, 2008, the FERC dismissed the request for rehearing.

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. We are the only 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.

The natural gas pipeline connecting the recently acquired Stiles Ranch gathering assets to our Arapaho processing plants carries natural gas across state lines. This pipeline is a gathering line that is not subject to FERC jurisdiction. 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.

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

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, on February 24, 2009, we filed to increase rates effective April 1. The increase incorporated index increases that were not fully taken over the last 3 years because of a previously effective settlement now expired.

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 transported or disposed or arranged for the transportation or disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and, under certain circumstances, joint and several 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.

Ongoing Remediation and Indemnification from a Third Party.

The previous owner/operator of our Cobb facility has been, or is currently involved in, investigatory or remedial activities with respect to the real property underlying this facility. 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 us against, any environmental liabilities associated with the EPA Administrative Order, the Kentucky Agreed Order or any other environmental condition related to the real property prior to the effective dates of our lease or purchase of the real property. In addition, the previous owner/operator has agreed to perform all the required response actions at its expense in a manner that minimizes interference with our use of the properties. 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 The Clean Water Act and analogous state law may also require individual permits or coverage under general permits for discharges of stormwater from certain types of facilities, but these requirements are subject to several exemptions specifically related to oil and gas operations and facilities. We conduct regular review of the applicable laws and regulations, and maintain discussions with the various state agencies with regard to have been in negotiations with the Pennsylvania State enumerated agency regarding the extent to which stormwater discharge permits may be required for the construction or operation of certain of our facilities associated with an expansion of our gathering system in the state. Such 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, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider, legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. As an alternative to cap and trade programs, the Congress may consider the implementation of a carbon tax system. The cap and trade programs could require major producers of fuels, such as natural gas or natural gas liquids processing plants operated by us, to acquire and surrender emission allowances. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we process. Also, as a result of the United States Supreme Court's 2007 decision in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks. The Court's holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, EPA released an "Advance Notice of Proposed Rulemaking" regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court's decision in *Massachusetts*. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could also have an adverse affect on our cost of doing business and demand for the natural gas and crude oil we gather as well as the natural gas and natural gas liquids we process.

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. During 2008, the DHS requested that we perform a Security Vulnerability Assessment for our Javelina plant. The DHS did not require us to perform any assessments with respect to our other facilities. We completed the assessment for our Javelina plant and submitted the assessment to the DHS for review in December 2008. We are also required to develop a written security plan for our Javelina plant and train our employees accordingly. While we do not currently anticipate incurring significant costs in connection with complying with these requirements, we have not yet received a response from the DHS regarding our assessment. It is possible that additional requirements could be imposed by the DHS in connection with this program, and complying with such requirements could result in additional costs that may 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 reinterpretation 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 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 adopted rules in June 2008 pursuant to authorization granted by the Pipeline Inspections, Protection, Enforcement, and

Safety Act of 2006 that amends it pipeline safety regulations to extend regulatory coverage to certain rural onshore hazardous liquid gathering lines and low stress pipelines located in specified "unusually sensitive areas," including non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species or other ecological sources. While we believe that our pipeline operations are in substantial compliance with applicable requirements, due to the possibility of new or amended laws and regulations, or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the requirements will not have a material adverse effect on our results of operations or financial position.

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., 471 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 20 employees at our Siloam fractionation facility in South Shore, Kentucky. The collective bargaining agreement with this union is currently being negotiated. 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 us.

Risks Inherent in Our Business

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 the current financial crisis or 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 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 wholly-owned subsidiaries, including our operating company (please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—*Liquidity and Capital Resources*). 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.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict and our ability to access the credit and capital markets on attractive terms to obtain funding for our capital projects may be limited due to the deterioration of these markets.

Changes in economic conditions could adversely affect our business and results of operations. A number of economic factors, including, but not limited to, gross domestic product, consumer interest rates, consumer confidence and debt levels, retail trends, housing starts, sales of existing homes, the level of mortgage refinancing, inflation and foreign currency exchange rates, may generally affect our business. Recessionary economic cycles, higher unemployment rates, higher fuel and other energy costs, and higher tax rates may adversely affect demand for natural gas, NGLs and crude oil. A decline in economic activity and conditions in the United States and any other markets in which we operate could adversely affect our financial condition and results of operations. There can be no assurances that government responses to disruptions in the financial markets will restore consumer confidence for the foreseeable future. The prevailing economic uncertainties may also render estimates of future income and expenditures very difficult to make.

The unprecedented and continued credit crisis and related turmoil in the global markets and financial systems and the decline in the U.S. economy in 2008, which have continued into 2009, have increased both the volatility and the amplitude of the risk associated with the other risk factors identified in this report. These events have had an impact on our yield and unit price, and may have an impact on our business and our financial condition. In particular, the cost of capital has increased substantially while the availability of funds from those markets has diminished significantly. Accordingly, our ability to access the capital markets may be restricted or be available only on unfavorable terms, which could significantly and adversely impact our ability to execute our long term organic growth projects. Limited access to the capital markets could also adversely impact our ability to otherwise take advantage of business opportunities or react to changing economic and business conditions. In addition, because of the recent turmoil in the financial markets, including issues surrounding solvency of many institutional lenders and the recent failure of several banks, our ability to obtain capital from the Amended Partnership Credit Agreement could be adversely impacted by the failure of one or more of the members of the participating bank group. Although the members of the participating bank group are investment grade, an increased risk does exist. Ultimately we may be required to substantially reduce our future capital expenditures. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on the common units. The current economic situation could have an impact on our lenders, producers, or other customers, causing them to fail to meet their obligations to us, and these market conditions could also have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations. The uncertainty and volatility of the unprecedented global financial crisis may have further impacts on our business and financial condition that we currently cannot predict or anticipate.

Furthermore, the current conditions of the global financial markets have contributed, and recent declines in commodity prices may have contributed, to a decline in our unit price and corresponding market capitalization. Continued declines in our market capitalization could result in an additional noncash impairment of our recorded goodwill. Continued declines in commodity prices could have an adverse impact on cash flows from operations that could result in noncash impairments of long-lived assets, as well as other-than-temporary noncash impairments of our equity method investments.

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.

Current economic conditions and the global financial crisis could impact the amount of cash generated from our operations and the amount of cash available for distribution to our unitholders. In 2008, we saw decreases in natural gas and NGL prices, and it is uncertain if these declines will continue in the future. In addition, adverse changes in the correlation between the price of NGLs and crude oil have reduced the effectiveness of our hedging program causing further reduction of our cash flows. Capital has become significantly more expensive, and the availability of capital has substantially diminished. Our ability to access the capital markets may be limited or may not be available on favorable terms, which may impact the level of capital expenditures we make, as well as our cash distribution levels. There could be other impacts on our business that we cannot currently anticipate.

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.

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

We are subject to significant risks associated with frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and NGLs have been volatile, and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price of natural gas for the prompt month contract in 2007 ranged from a high of $8.64 per MMBtu to a low of $5.38 per MMBtu. In 2008, the same index ranged from a high of $13.58 per MMBtu to a low of $5.29

per MMBtu. A composite of the weighted monthly average NGLs price at our Appalachian facilities based on our average NGLs composition in 2007 ranged from a high of approximately $1.76 per gallon to a low of approximately $0.96 per gallon. In 2008, the same composite ranged from approximately $2.24 per gallon to approximately $0.55 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.

In 2008, due to the financial crisis and market conditions, natural gas and NGL prices declined and were subject to increased volatility. It is uncertain if the volatility of, and decline in, natural gas and NGL prices will continue during 2009.

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

Due to timing of gas purchases and liquid sales, direct exposure to changes in market prices of either gas or liquids can be created because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Through our marketing and derivatives activity, direct exposure may occur naturally or we may choose direct price exposure to either gas or liquids when we favor that exposure over frac spread risk. Given that we have derivative positions, adverse movement in prices to the positions we have 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 settle all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, which could result in a substantial diminution of our liquidity. Additionally, because we primarily use derivative financial instruments relating to the future price of crude oil to mitigate our exposure to NGL price risk, the volatility or our future cash flows and net income may increase if there is a change in the pricing relationship between crude oil and NGLs. As a result of these factors, our 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.

We conduct risk management activities but we 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. We have discretion in determining whether and how to manage the commodity price risk associated with our physical and derivative positions.

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

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. The increased cost of capital in the current market environment may make it more difficult for producers to finance drilling programs around our systems which could lead to decreased volumes. In addition, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. We have seen decreases in the prices of natural gas in connection with the current economic crisis, and it is uncertain if these declines will continue in the future. 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 usually under no obligation to deliver a specific quantity of natural gas or NGLs to our facilities. If these key suppliers, or a significant number of other producers, were to decrease the supply of natural gas or NGLs to our systems and facilities for any reason, we could experience difficulty in replacing those lost volumes. Because our operating costs are primarily fixed, a reduction in the volumes of natural gas or NGLs delivered to us would result not only in a reduction of revenues, but also a decline in net income and cash flow.

Growing our business by constructing new pipelines and processing and treating facilities subjects us to construction risks and risks that natural gas 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.

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. Prevailing economic conditions may increase this risk, due to declines in natural gas and NGL prices, reduced access to capital, and increased uncertainty in the financial markets. 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—*Competition* of Part 1 of this report.

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. The FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, the costs we incur in our operations, the construction of new facilities or our ability to recover the full cost of operating our pipelines. 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.

Some of our natural gas transportation operations are subject to Federal Energy Regulatory Commission's rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return.

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

For example, one such matter relates to the FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. In May 2005, the FERC adopted a policy statement ("Policy Statement"), stating that it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect actual or potential tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to the Policy Statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. This tax allowance policy was upheld by the D.C. Circuit in May 2007.

In December 2006, FERC issued an order addressing income tax allowance in rates, in which it reaffirmed prior statements regarding its income tax allowance policy, but raised a new issue regarding the implications of the Policy Statement for publicly traded partnerships.

Whether a pipeline's owners have actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. How the Policy Statement is applied in practice to pipelines owned by publicly traded partnerships could impose limits on our ability to include a full income tax allowance in cost of service.

The FERC instituted a rulemaking proceeding in July 2007 to determine whether any changes should be made to the FERC's methodology for determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. Certain parties have advocated that the FERC disallow the full use of cash distributions in the return on equity calculation. If the FERC were to disallow the use of full cash distributions in the return on equity calculation, such a result might adversely affect our ability to achieve a reasonable return on our regulated assets.

The outcome of certain FERC proceedings involving FERC policy statements is uncertain and could affect the level of return on equity that the Partnership may be able to achieve in any future rate proceeding.

In an effort to provide some guidance and to obtain further public comment on FERC's policies concerning return on equity determinations, on July 19, 2007, FERC issued its Proposed Proxy Policy Statement, *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*. In the Proposed Proxy Policy Statement, FERC proposes to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that certain conditions are met. Shortly after the FERC issued this Proposed Proxy Policy Statement, the D.C. Circuit vacated FERC's orders in a related proceeding and determined that FERC had failed to adequately reflect risks of interstate pipeline operations by populating the proxy group with entities that had lower risk, while excluding publicly traded partnerships primarily engaged in interstate pipeline operations. The ultimate outcome of these proceedings is not certain and may result in new policies being established at FERC that would not allow the full use of publicly traded partnership distributions to unitholders in any proxy group comparisons used to determine return on equity in future rate proceedings. In addition, the FERC may adopt other policies or institute other proceedings that could adversely affect our ability to achieve a reasonable level of return on equity on our regulated assets.

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 certain of our facilities are located and our results of operation and our ability to make distributions to our unitholders could be adversely affected if 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 us against, any environmental liabilities associated with these regulatory orders or the real property underlying these facilities to the extent such liabilities arose prior to the effective date of the agreements pursuant to which such properties were acquired or leased from Columbia Gas. Our results of operation and our ability to make cash distributions to our unitholders could be adversely affected if in the future Columbia Gas 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, state, regional and local 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. Strict and, under certain circumstances, joint and several liability may be incurred without regard to fault, or the legality of the original conduct, under certain of the environmental laws for remediation of contaminated areas, including 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 to 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 including increasing or maintaining distributions, 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 and acts of terrorism;
- 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, Rita and Ike in the Gulf of Mexico and Gulf Coast regions in 2005 and 2008, 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 and 2008, Hurricanes Katrina, Rita and Ike 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. After the hurricanes in 2005, we 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. As a result of the hurricane damages in 2008 and further increases in insurance costs, 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. Our equity based long-term incentive plans are a significant component of our strategy to retain key employees. The recent decline in the market price of our common units has reduced the value of the incentives provided by these plans and could reduce their effectiveness. 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.

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 are applicable to our existing plants, pipelines and facilities. If so, our operation of these new assets could cause us to incur increased costs to address these liabilities or to attain or maintain compliance with such requirements. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we 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.

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.

We have partial ownership interests in a number of joint venture legal entities, including Liberty, Wirth, Centrahoma and Starfish, which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and where we do not have control, we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

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

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

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

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.

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.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based on our current operations that we are so treated, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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

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. The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial, or administrative changes and differing interpretations at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Recently, members of Congress considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will be considered or 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 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. The Partnership is required to pay a 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.

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 could 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 Class A unitholders and our common unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

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

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

The sale or exchange of 50% or more of our capital and profits interests during any 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. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in 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, other than Texas, impose personal income taxes. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholder's responsibility to file all United States federal, foreign, state and local tax returns.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

The following tables set forth certain information relating to our gas processing facilities, fractionation facility, natural gas pipelines, NGL pipelines, and crude oil pipeline as of and for the year ended December 31, 2008.

Gas Processing Facilities:

				Year ended December 31, 2008		
Facility	Location	Year of Initial Construction	Design Throughput Capacity	Natural Gas Throughput	Utilization of Design Capacity	NGL Throughput
			(Mcf/d)	(Mcf/d)		(Gal/d)
Southwest						
East Texas:						
East Texas processing plant	Panola County, TX	2005	280,000	203,800	73%	N/A
Oklahoma:						
Arapaho processing plants	Custer County, OK	2000	160,000	150,000	94%	217,000
Northeast						
Appalachia:						
Kenova processing plant(1)	Wayne County, WV	1996	160,000	131,100	82%	N/A
Boldman processing plant(1)	Pike County, KY	1991	70,000	44,400	63%	N/A
Cobb processing plant	Kanawha County, WV	2005	30,000	26,700	89%	N/A
Kermit processing plant(1)(2)	Mingo County, WV	2001	32,000	N/A	N/A	N/A
Marcellus Shale:						
Houston interim processing plant(3)	Washington County, PA	2008	30,000	18,700	62%	N/A
Gulf Coast						
Javelina processing plant	Corpus Christi, TX	1989	142,000	122,900	87%	1,025,800

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

(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.

(3) The Houston interim processing plant is a leased facility which began operation in October 2008. The volume reported is the average daily rate for the days of operation.

Fractionation Facility:

Facility	Location	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2008 NGL Throughput	Year ended December 31, 2008 Utilization of Design Capacity
			(Gal/d)	(Gal/d)	
Northeast					
Appalachia:					
Siloam fractionation plant	South Shore, KY	1957	600,000	519,500	87%

Natural Gas Gathering Systems:

Facility	Location	Miles	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2008 Natural Gas Throughput	Year ended December 31, 2008 Utilization of Design Capacity
				(Mcf/d)	(Mcf/d)	
Southwest						
East Texas:						
East Texas gathering system	Panola County, TX	440	1990	500,000	442,900	89%
Oklahoma:						
Foss Lake gathering system	Roger Mills, Ellis and Custer Counties, OK	325	1998	130,000	95,700	74%
Stiles Ranch gathering system(4) .	Wheeler County, TX	125	2008	120,000	84,800	71%
Grimes gathering system	Beckham and Roger Mills Counties, OK	40	2005	25,000	12,900	52%
Southeast Oklahoma gathering system	Hughes, Pittsburg and Coal Counties, OK	711	2006	700,000	318,700	46%
Other Southwest:						
Appleby gathering system	Nacogdoches County, TX	140	1990	85,000	58,400	69%
Other gathering systems	Various		Various	36,500	11,000	30%
Northeast						
Michigan:						
Gas gathering system	Manistee, Mason and Oceana Counties, MI	90	1994 - 1998	35,000	3,200	9%
Marcellus Shale:						
Gas gathering system	Washington County, PA	21	2008	30,000	18,700	62%

(4) Stiles Ranch began operating in November 2008. The volume reported is the average daily rate for the days of operation.

NGL Pipelines:

Pipeline	Location	Miles	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2008 NGL Throughput	Utilization of Design Capacity
				(Gal/d)	(Gal/d)	
Northeast						
Appalachia:						
Ranger to Kenova(5)	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	275,200	33%
Southwest						
East Texas:						
East Texas liquidline	Panola County, TX	37.5	2005	630,000	528,800	84%

(5) 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, 2008 NGL Throughput	Utilization of Design Capacity
				(Bbl/d)	(Bbl/d)	
Northeast						
Michigan:						
Michigan crude pipeline	Manistee County, MI to Crawford County, MI	250	1973	60,000	13,300	22%

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 and those of our wholly-owned subsidiaries as collateral for borrowings under our Partnership Credit Agreement.

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; or for third-party claims of personal and property damage; or that the coverages or levels of insurance we currently have will be available in the future at economical prices. While it is not possible to predict the outcome of the legal actions with certainty, management is of the opinion that appropriate 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, L.L.C. 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 would ultimately recover under the policies. The Defendant insurance companies and MarkWest had each filed separate summary judgment motions in the action. On April 23, 2008, the Court issued an order granting Defendant insurance companies' motion for summary judgment. The Partnership believes the Court's analysis and decision is in error, legally and factually, on numerous grounds and has filed an appeal of this Order to the 10th Circuit Court of Appeals (Case No. 08-1186). The Partnership and the Defendant insurance companies have filed briefs in connection with the appeal, and oral arguments were presented to the 10th Circuit Court of Appeals on January 15, 2009 and the parties are awaiting the Court's decision.

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); 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 parties in the *Gutierrez* action have been in settlement discussions, have reached an agreement in principle to settle the case for an immaterial amount, and are working towards a final settlement agreement. 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 financial position or results of operations.

In the ordinary course of business, we are 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 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, 2008.

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.

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 2008 and 2007:

Quarter Ended	High	Low	Distribution Per Common Unit	Distribution Per Subordinated Unit(1)	Record Date	Payment Date
December 31, 2008 . .	$25.75	$ 6.55	$0.64	$ —	February 6, 2009	February 13, 2009
September 30, 2008 . .	36.00	21.22	0.64	—	November 4, 2008	November 14, 2008
June 30, 2008	38.50	30.70	0.63	—	August 4, 2008	August 15, 2008
March 31, 2008	37.00	29.53	0.60	—	May 5, 2008	May 15, 2008
December 31, 2007 . .	34.71	29.55	0.57	—	February 7, 2008	February 14, 2008
September 30, 2007 . .	37.25	29.78	0.55	—	November 8, 2007	November 14, 2007
June 30, 2007	38.00	33.27	0.53	0.53	August 8, 2007	August 14, 2007
March 31, 2007	36.45	28.51	0.51	0.51	May 9, 2007	May 15, 2007

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

As of February 23, 2009 there were 176 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;
- 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 MarkWest Hydrocarbon, Inc.

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 $0.75 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 quarterly distribution on the common units in any quarter.

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, 2008, regarding our common units that may be issued upon conversion of outstanding phantom units granted under all of our existing equity compensation plans.

	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:			
2008 Long-Term Incentive Plan(2)	877,331	$—	1,622,669
2006 Hydrocarbon Stock Incentive Plan(3)(4)	24,171	$—	—
1996 Hydrocarbon Stock Incentive Plan(3)(4)	7,804	$—	—
Equity compensation plans not approved by security holders:	—	$—	—
Long-Term Incentive Plan(4)	145,927	$—	—
Total	1,055,233		1,622,669

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

(2) Includes 463,500 performance-based units which vest if the Partnership achieves established performance goals determined by the Compensation Committee of the General Partner's board of directors.

(3) Outstanding shares of restricted stock under these plans were converted to phantom units pursuant to the terms of the Merger. The converted phantom units will remain outstanding under the terms of their original respective plans until their respective settlement dates. No further awards will be made pursuant to these plans.

(4) Upon the closing of the Merger, no further awards will be made pursuant to this plan.

ITEM 6. Selected Financial Data

The following table sets forth selected consolidated historical financial and operating data for MarkWest Energy Partners. As a result of the Merger, the historical and comparative financial data is that of MarkWest Hydrocarbon, Inc. All historical unit and per unit data has been adjusted to reflect the Exchange Ratio to give effect of the Merger. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation in this Form 10-K.

	Year ended December 31,				
	2008	2007	2006	2005(1)	2004(2)
	($ in thousands, except per unit amounts)				
Statement of Operations:					
Revenue:					
Revenue	$1,060,662	$ 845,727	$ 829,298	$ 759,381	$ 482,483
Derivative gain (loss)(3)	277,828	(159,970)	10,383	(3,198)	(4,565)
Total revenue	1,338,490	685,757	839,681	756,183	477,918
Operating expenses:					
Purchased product costs	615,902	487,892	560,597	625,090	381,066
Derivative loss related to purchased product costs(3)	22,371	15,192	5,689	—	—
Facility expenses	103,682	70,863	57,403	45,577	28,580
Derivative loss (gain) related to facility expenses(3)	644	(14)	—	—	—
Selling, general and administrative expenses	68,975	72,484	63,360	33,757	28,195
Depreciation	67,480	41,281	31,010	20,829	16,895
Amortization of intangible assets	38,483	16,672	16,047	9,656	3,640
Loss (gain) on disposal of property, plant and equipment	178	7,743	(322)	(407)	(63)
Accretion of asset retirement obligations	129	114	102	160	15
Impairment of goodwill and long-lived assets	36,351	356	—	—	130
Total operating expenses	954,195	712,583	733,886	734,662	458,458
Income (loss) from operations	384,295	(26,826)	105,795	21,521	19,460
Other income (expense):					
Earnings (loss) from unconsolidated affiliates	90	5,309	5,316	(2,153)	—
Impairment of unconsolidated affiliate	(41,449)	—	—	—	—
Interest income	3,769	4,547	1,574	1,060	647
Interest expense	(64,563)	(39,435)	(40,942)	(22,622)	(9,383)
Amortization of deferred financing costs and discount (a component of interest expense)	(8,299)	(2,983)	(9,229)	(6,979)	(5,281)
Miscellaneous (expense) income	(241)	233	11,984	658	1,047
Income (loss) before non-controlling interest in net income of consolidated subsidiaries and provision for income tax	273,602	(59,155)	74,498	(8,515)	6,490
Non-controlling interest in net loss (income) of consolidated subsidiaries	3,301	(4,853)	(59,709)	(91)	(7,315)
Income (loss) before provision for income tax	276,903	(64,008)	14,789	(8,606)	(825)
Provision for income tax expense (benefit):					
Current	15,032	23,869	(179)	554	20
Deferred	53,798	(48,518)	5,431	(2,358)	58
Total provision for income tax	68,830	(24,649)	5,252	(1,804)	78
Net income (loss)	$ 208,073	$ (39,359)	$ 9,537	$ (6,802)	$ (903)
Net income (loss) per common unit(4) (Note 21):					
Basic	$ 4.08	$ (1.72)	$ 0.42	$ (0.30)	$ (0.04)
Diluted	$ 4.04	$ (1.72)	$ 0.42	$ (0.30)	$ (0.04)
Cash distribution declared per common unit(4)	$ 2.059	$ 0.703	$ 0.416	$ 0.191	$ 0.046

	Year ended December 31,				
	2008	2007	2006	2005(1)	2004(2)
	($ in thousands, except per unit amounts)				
Balance Sheet Data (at December 31):					
Working capital	$ 51,237	$ 21,932	$ 66,030	$ 61,156	$ 53,907
Property, plant and equipment, net	1,569,525	830,809	554,335	494,698	283,193
Total assets	2,673,054	1,524,695	1,203,241	1,132,304	593,574
Total long-term debt	1,172,965	552,695	526,865	608,762	225,000
Partners' capital	1,204,458	39,391	41,489	39,982	49,761
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 226,995	$ 133,237	$ 165,969	$ 16,874	$ 26,616
Investing activities	(909,265)	(314,792)	(122,046)	(445,848)	(303,017)
Financing activities	647,896	170,406	(16,047)	437,098	247,101
Other Financial Data:					
Maintenance capital expenditures(5)	$ 7,161	$ 4,140	$ 2,460	$ 2,181	$ 1,163
Growth capital expenditures(5)	568,137	312,499	77,620	69,162	29,491
Total capital expenditures	$ 575,298	$ 316,639	$ 80,080	$ 71,343	$ 30,654

(1) We completed our initial 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) Revenues, purchased product costs 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 unrealized gains and losses to be offset when they become realized. The following table summarizes the realized and unrealized gains and losses impacting *Revenue*, *Purchased product costs* and *Facility expenses* for the year ended December 31 (in thousands):

	2008	2007	2006	2005	2004
Realized (loss) gain—revenue	$(15,704)	$ (15,901)	$ 17	$(2,541)	$(4,410)
Unrealized gain (loss)—revenue	293,532	(144,069)	10,366	(657)	(155)
Realized gain (loss)—purchased product costs	7,368	(8,829)	153	—	—
Unrealized loss—purchased product costs	(29,739)	(6,363)	(5,842)	—	—
Unrealized (loss) gain—facility expenses	(644)	14	—	—	—
Total derivative gain (loss)	$254,813	$(175,148)	$ 4,694	$(3,198)	$(4,565)

(4) All per unit data where applicable has been adjusted to reflect the Exchange Ratio to give effect to the Merger (see Note 3 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

(5) Maintenance capital includes capital expenditures made to maintain our operating capacity and asset base. Growth capital includes expenditures made to expand the existing operating capacity, increase the efficiency of our existing assets, costs associated with new well connections or facilitate an increase in volumes within our operations. Our 2008 growth capital excludes $41.3 million paid to acquire PQ Gathering Assets, L.L.C. and our $29.2 million equity investment in Centrahoma.

Operating Data

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Southwest					
East Texas					
Gathering systems throughput (Mcf/d)	442,900	413,700	378,100	321,000	259,300
NGL product sales (gallons)	193,534,100	179,601,000	161,437,000	126,476,000	41,478,000
Oklahoma					
Foss Lake gathering systems throughput (Mcf/d)	95,800	104,000	87,500	75,800	60,900
Stiles Ranch gathering system throughput (Mcf/d)(1)	84,800	N/A	N/A	N/A	N/A
Grimes gathering system throughput (Mcf/d)(2)	12,900	12,500	N/A	N/A	N/A
Arapaho NGL product sales (gallons)	79,416,400	87,522,000	79,093,000	60,903,000	45,273,000
Southeast Oklahoma gathering systems throughput (Mcf/d)(3)	318,700	114,000	34,000	N/A	N/A
Other Southwest					
Appleby gathering systems throughput (Mcf/d)	58,400	58,700	34,200	33,400	27,100
Other gathering systems throughput (Mcf/d)(4)	11,000	8,700	18,300	16,500	17,000
Northeast					
Appalachia(5)					
Natural gas processed (Mcf/d)	202,200	200,200	203,000	197,000	203,000
Keep-whole sales (gallons)	140,847,500	126,192,600	118,581,000	120,300,000	135,895,000
Percent-of-proceeds sales (gallons)	53,987,900	43,815,100	43,271,000	41,700,000	42,105,000
Total NGL product sales (gallons)(6)	194,835,400	170,007,700	161,852,000	162,000,000	178,000,000
Marcellus Shale(7)					
Natural gas processed (Mcf/d)	18,700	N/A	N/A	N/A	N/A
Michigan					
Natural gas processed for a fee (Mcf/d)	3,200	5,200	6,500	6,600	12,300
NGL product sales (gallons)	2,954,400	3,898,600	5,643,000	5,697,000	9,818,000
Crude oil transported for a fee (Bbl/d)	13,300	14,000	14,500	14,200	14,700
Gulf Coast(8)					
Refinery off-gas processed (Mcf/d)	122,900	114,500	124,300	115,000	N/A
Liquids fractionated (Bbl/d)	24,400	25,000	26,200	19,400	N/A

(1) In August 2008, we entered into an agreement to acquire the Stiles Ranch gathering system. The 2008 volume reported is the average daily rate for the period of operation, which began November 2008.

(2) We acquired the Grimes gathering system on December 29, 2006.

(3) 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 Southeastern 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.

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

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

(6) Represents sales at the Siloam fractionator.

(7) The 2008 volume reported is the average daily rate for the period of operation, which began October 2008.

(8) 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 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 strategy is to expand our asset base through organic growth projects and selective acquisitions that are accretive to our cash available for distribution.

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 Corporation for periods prior to the Merger.

The current constraints in the capital markets may affect our ability to obtain additional funding through new borrowings or the issuance of common units. In addition, we expect that, to the extent we are successful in arranging new debt financing, we will incur increased costs. In light of the current market conditions, we have taken steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, considering additional joint venture arrangements, considering the sale of non-strategic assets, evaluating the continuation of our cash distribution rate and continuing to appropriately manage operating and administrative costs to improve profitability.

We believe that the size and scope of our operations, our stable asset base and cash flow profile will be significant positive factors in our efforts to obtain new debt or equity funding; however, there is no assurance that we will be successful in obtaining financing under any of the alternatives discussed above if current capital market conditions continue for an extended period of time or if markets deteriorate further from current conditions. Furthermore, the terms, size and cost of any one of these financing alternatives could be less favorable and could be impacted by the timing and magnitude of our funding requirements, market conditions, and other uncertainties.

Current economic conditions also indicate that many of our customers may encounter increased credit risk in the near term. In particular, our natural gas and NGL gathering, transportation and processing revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas and NGLs have fallen dramatically since July 2008. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our customers to announce plans to decrease drilling levels and, in some cases, to consider shutting in natural gas production from some producing wells.

Under certain types of contracts, our revenues and net operating margin are directly affected by underlying commodity prices, specifically changes in the price of natural gas and NGLs. Further, we use crude oil to hedge our long NGL positions and while the price of NGLs are correlated to the price of crude oil, changes in the correlation between NGLs and the price of crude oil will also affect our revenue and net operating margin. Additionally, while low natural gas prices may be favorable in the short-term relative to our keep-whole arrangements, our revenues and operating cash flows from natural gas operations may be adversely affected by long-term declines in natural gas prices if our customers reduce their drilling activity. For the year ended December 31, 2008, percent-of-proceeds, percent-of-index and keep-whole arrangements accounted for 75% of our net operating margin and fee-based arrangements account for 25% of our net operating margin.

We maintain an active hedging program to mitigate our exposure to commodity risk. For further discussion of how we have reduced the downside volatility to the portion of our net operating margin that is not fee-based, see Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk of this Form 10-K.

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 eleven acquisitions (excluding the Merger) for an aggregate purchase price of $875 million, net of working capital. Eight of these acquisitions occurred in 2003, 2004 and 2005 and their results are included in the results of operations from the acquisition date.

One acquisition occurred in 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 the Grimes gathering system is reflected in the consolidated results of operations beginning in 2007.

Two acquisitions occurred in 2008 and are included in the results of operations from the acquisition date.

- On March 1, 2008, we acquired a 20% interest in Centrahoma for $11.6 million, which is accounted for under the equity method. On May 9, 2008, we acquired an additional 20% interest in Centrahoma for $12.0 million including a capital call, which brings the Partnership's total ownership interest to 40%. As a result, the Partnership's share of Centrahoma's net loss from March 2008 to December 2008 is included in *Earnings from unconsolidated affiliates* in the accompanying Consolidated Statements of Operations for the year ended December 31, 2008.
- The PQ Assets acquisition closed on July 31, 2008 for consideration of $41.3 million. As a result, five months of activity for PQ Assets is reflected in the accompanying Consolidated Statements of Operations beginning in 2008.

Results of Operations

We reported net income of $208.1 million for the year ended December 31, 2008 compared to net loss of $39.4 million for the year ended December 31, 2007. Contributing factors to the $247.4 million change in net income were:

- a $430.0 million increase in gains from derivative instruments which are primarily unrealized. This change is due primarily to the significant decline in crude oil prices in the fourth quarter of 2008. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for further information on the potential volatility to our unrealized gains and losses.

- a $54.0 million increase in operating income before items not allocated to segments in the Southwest segment. This increase is due primarily to the continued expansion in the Woodford Shale area. Increased volumes and higher annual average pricing for the NGLs sold under the percent-of-proceeds arrangements in East Texas also contributed significantly to the increase.
- a $48.0 million increase in depreciation and amortization expense due to the additional depreciation related to the step-up in basis resulting from the Merger and the increasing asset base related to our continued expansion.
- a $93.5 million change in the income tax provision from a $24.6 million tax benefit in 2007 to a $68.8 million tax expense in 2008 due primarily to the increase in pretax income. Approximately $53.8 million of the 2008 tax expense is deferred. For further discussion of income taxes see Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.
- a $25.1 million increase in interest expense related to additional borrowings to finance internal growth projects and acquisitions and the Merger.
- a $36.0 million increase in impairment expenses related to the $28.7 million write down of goodwill and the $7.6 million impairment of our natural gas gathering and processing assets located in Manistee County, Michigan which are part of the Northeast segment.
- a $41.4 million impairment charge due to an other-than-temporary decline in the fair value of our equity investment in Starfish. See Note 12 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of this impairment.

Segment Reporting

We classify our business in three reportable segments: Southwest, Northeast and Gulf Coast. We capture information in this MD&A by geographical segment. Items below *Income (loss) from operations* in the accompanying Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any unrealized gains (losses) from derivative instruments are not allocated to individual business segments. Management does not consider these items allocable to or controllable by any individual business segment and therefore excludes these items when evaluating segment performance. The segment information appearing in Note 23 of the accompanying Notes to Consolidated Financial Statements included 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.* As a result of the Merger, segment information for the years ended December 31, 2007 and 2006 has been recast.

Year Ended December 31, 2008, Compared to Year Ended December 31, 2007

The tables below present information about operating income for the reported segments for the years ended December 31, 2008 and 2007.

Southwest

	Year ended December 31, 2008	2007	$ Change	% Change
	(in thousands)			
Revenue	$652,365	$503,461	$148,904	30%
Operating expenses:				
Purchased product costs	387,516	310,888	76,628	25%
Facility expenses	62,369	44,045	18,324	42%
Total operating expenses before items not allocated to segments	449,885	354,933	94,952	27%
Operating income before items not allocated to segments	$202,480	$148,528	$ 53,952	36%

Revenue. Revenue increased for the year ended December 31, 2008, relative to 2007, due primarily to an increase in volumes and higher average annual pricing in most areas of the segment. Revenue in East Texas increased $75.2 million from the sale of greater NGL and condensate volumes and higher prices for most of the year. Additionally, continued expansion in the Woodford gathering system, including the purchase of PQ Assets from PetroQuest Energy, L.L.C., and the start of gas processing operations in this area increased revenue approximately $63.4 million. Revenue from Other Southwest areas increased approximately $39.3 million due to higher average annual prices and increased volumes of approximately 2,000 Mcf/d in the gathering systems. Revenue generated by the Foss Lake region decreased $28.9 million mainly due to lower volumes.

Purchased Product Costs. Purchased product costs increased during the year ended December 31, 2008, relative to 2007, due primarily to the increased NGL purchases in East Texas related to percent-of-proceeds arrangements. Additional increases are related to the increased volumes and higher prices in the Other Southwest areas. Additional NGL and gas purchases associated with the Woodford expansion also contributed to the increase.

Facility Expenses. Facility expenses increased during the year ended December 31, 2008, relative to 2007, due primarily to the increased operations for the Woodford gathering system. Expanded operations in East Texas and Western Oklahoma also contributed to the increase in facility expenses.

Northeast

	Year ended December 31, 2008	2007	$ Change	% Change
	(in thousands)			
Revenue	$316,255	$265,152	$51,103	19%
Operating expenses:				
Purchased product costs	228,386	177,004	51,382	29%
Facility expenses	22,875	16,347	6,528	40%
Total operating expenses before items not allocated to segments	251,261	193,351	57,910	30%
Operating income before items not allocated to segments	$ 64,994	$ 71,801	$(6,807)	(9)%

Revenue. Revenue increased during the year ended December 31, 2008, relative to 2007, due mainly to higher average annual prices and increased volumes of NGLs sold from the Appalachia region. The increase in volumes resulted from the expanded production of a large producer customer in the area and upgrades to our processing facilities.

Purchased Product Costs. Purchased product costs increased during the year ended December 31, 2008, relative to 2007, mainly due to higher average annual prices for natural gas that must be purchased to satisfy the keep-whole arrangements in the Appalachia area, and an increase in the volumes of natural gas purchased. Purchased product costs also includes an expense of $6.7 million to write down inventories to market value at December 31, 2008. The increase in purchased product costs was partially offset by a $3.0 million decrease in trucking expenses resulting from a change in contractual terms with a producer.

Facility Expenses. Facility expenses increased during the year ended December 31, 2008, relative to 2007, due primarily to increases in plant fuel costs, repairs and maintenance expense and labor and benefits expense to support the increased level of operations in the Appalachia region.

Gulf Coast

	Year ended December 31, 2008	Year ended December 31, 2007	$ Change	% Change
	(in thousands)			
Revenue	$92,042	$77,114	$14,928	19%
Operating expenses:				
Facility expenses	17,368	10,471	6,897	66%
Total operating expenses before items not allocated to segments	17,368	10,471	6,897	66%
Operating income before items not allocated to segments	$74,674	$66,643	$ 8,031	12%

Revenue. Revenue increased during the year ended December 31, 2008, relative to 2007. The increase is due mainly to higher pricing and inlet volumes partially offset by a slightly lower percent-of-proceeds ("POP") received. Effective March 1, 2008, a significant contract changed from a fixed POP to variable POP, resulting in a lower POP received. In addition, the sale of pentanes generated $10.2 million of revenue for the year ended December 31, 2008, compared to $4.8 million for the same period in 2007. Historically, pentanes had to be stored and were sold seasonally. However, with the completion of a new pentane hydrotreater in March 2008, the quality of the pentanes has been improved, and they can be sold on a recurring basis as they are produced.

Facility Expenses. Facility expenses increased during the year ended December 31, 2008, relative to 2007, due partially to a refund of $3.6 million from a utility rate case concluded in the first quarter of 2007. Excluding the refund, facility expenses were $3.2 million higher due mainly to increased energy expenses related to a new contract in March 2008 whereby the Partnership shares the cost of electricity. In 2007 these expenses were fully reimbursed by the customer.

Reconciliation of Segment Operating Income to Consolidated Net Income (Loss) Before Non-Controlling Interest and Provision for Income Tax

The following table provides a reconciliation of revenue and operating income before items not allocated to segments to our consolidated net income (loss) before non-controlling interest and provision for income tax for the years ended December 31, 2008 and 2007. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

	Year ended December 31, 2008	2007	$ Change	% Change
	(in thousands)			
Total segment revenue	$1,060,662	$ 845,727	$214,935	25%
Derivative gain (loss) not allocated to segments	277,828	(159,970)	437,798	(274)%
Total revenue	$1,338,490	$ 685,757	$652,733	95%
Operating income before items not allocated to segments	$ 342,148	$ 286,972	$ 55,176	19%
Derivative gain (loss) not allocated to segments	254,813	(175,148)	429,961	(245)%
Compensation expense included in facility expenses not allocated to segments	(1,070)	—	(1,070)	N/A
Selling, general and administrative expenses	(68,975)	(72,484)	3,509	(5)%
Depreciation	(67,480)	(41,281)	(26,199)	63%
Amortization of intangible assets	(38,483)	(16,672)	(21,811)	131%
Loss on disposal of property, plant and equipment	(178)	(7,743)	7,565	(98)%
Accretion of asset retirement obligations	(129)	(114)	(15)	13%
Impairment of goodwill and long-lived assets	(36,351)	(356)	(35,995)	10,111%
Income (loss) from operations	384,295	(26,826)	411,121	(1,533)%
Earnings from unconsolidated affiliates	90	5,309	(5,219)	(98)%
Impairment of unconsolidated affiliate	(41,449)	—	(41,449)	N/A
Interest income	3,769	4,547	(778)	(17)%
Interest expense	(64,563)	(39,435)	(25,128)	64%
Amortization of deferred financing costs and discount (a component of interest expense)	(8,299)	(2,983)	(5,316)	178%
Miscellaneous (expense) income	(241)	233	(474)	(203)%
Income (loss) before non-controlling interest in net income of consolidated subsidiaries and provision for income tax	$ 273,602	$ (59,155)	$332,757	(563)%

Derivative (Gain) Loss. Derivative gains were $254.8 million for the year ended December 31, 2008, compared to derivative losses of $175.1 million for the year ended December 31, 2007. The change of $430.0 million is primarily attributable to the significant decline in commodity prices in the fourth quarter of 2008. Approximately $413.6 million of the change relates to unrealized gains due to mark-to-market adjustments. Settlements of our derivative instruments resulted in a $16.4 million decrease in realized losses, when comparing 2008 to 2007 results. The decrease in realized derivative losses is primarily attributable to management's decision to settle certain 2010 and 2011 frac spread positions in November and December of 2008. We recognized $28.0 million of net gains during the year ended December 31, 2008 resulting from the settlement of these 2010 and 2011 positions. The settlements were completed prior to 2010 and 2011 to improve liquidity and to mitigate credit risk with certain counterparties, and as such does not represent trading activity. These gains on the early settlement of the 2010 and 2011 positions partially offset the $36.3 million of realized losses resulting from the scheduled settlement of the 2008 positions.

Selling, General and Administrative Expenses. Selling, general and administrative expenses decreased during the year ended December 31, 2008, relative to 2007, due primarily to a $12.2 million decrease in compensation expense related to the Participation Plan and a decrease in Merger-related expenses of $3.8 million. Refer to Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the Participation Plan. These decreases in costs were partially offset by an $8.7 million increase in compensation expenses related to phantom unit awards. Increases in professional consulting expenses, office rent expense, letter of credit fees, and novation expenses also partially offset the overall decrease in selling, general, and administrative expenses.

Depreciation and Amortization of Intangible Assets. Depreciation and amortization expense increased during the year ended December 31, 2008, relative to 2007, due primarily to a $32.5 million increase caused by the step-up in value of property, plant, and equipment and intangible assets as a result of the Merger. The remainder is due to depreciation on additional projects completed during the fiscal years ended 2008 and 2007.

Impairment of Goodwill and Long-Lived Assets. During the year ended December 31, 2008, we recognized an impairment charge of $28.7 million related to goodwill that was recorded a result of the purchase accounting for the Merger. The impairment is due primarily to a reduction in our forecasted cash flows caused by a significant decline in commodity prices in the fourth quarter of 2008. Refer to Note 11 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion.

During the year ended December 31, 2008, we recognized an impairment charge of $7.6 million related to certain gas-gathering assets in the Northeast segment. During the year ended December 31, 2007, we recognized an impairment charge of $0.4 million related to assets in the Southwest segment. Refer to Note 11 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion.

Loss on Disposal of Property, Plant, and Equipment. The loss from disposal of property, plant and equipment decreased during the year ended December 31, 2008, relative to 2007. The $7.7 million loss during the year ended 2007 related primarily to the conveyance of the Maytown facility to Equitable and the write-off of leasehold improvements as a result of the termination of the pipeline lease with Equitable in November 2007. There were no significant disposals during 2008.

Earnings from Unconsolidated Affiliates. Earnings from unconsolidated affiliates are primarily related to our investment in Starfish, a joint venture with Enbridge Offshore Pipelines L.L.C. which is accounted for using the equity method. The decrease in our earnings from unconsolidated affiliates for the year ended December 31, 2008, relative to 2007, is due mainly to the damage and business interruption caused by Hurricane Ike in September 2008 (refer to *Matters Impacting Future Results* for additional discussion).

Impairment of Unconsolidated Affiliate. During the year ended December 31, 2008, we recognized an impairment charge of $41.4 million related to an other-than-temporary decline in the fair value of our equity investment in Starfish. See Note 12 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details regarding this impairment charge.

Interest Income. Interest income decreased during the year ended December 31, 2008, relative to 2007, mainly due to proceeds received in the first quarter of 2007 from a rate case in our Gulf Coast segment. This decrease was partially offset by interest earnings on additional money market investments resulting from the cash raised in the debt and equity offerings in April 2008.

Interest Expense. Interest expense increased during the year ended December 31, 2008, relative to 2007, primarily due to increased borrowings in 2008 to fund the Merger and to raise funds for acquisitions and organic growth projects.

Amortization of Deferred Financing Costs and Discount. Amortization of deferred financing costs and discount increased during the year ended December 31, 2008, relative to 2007, due mainly to the $4.2 million write-off of financing costs related to a term loan that was repaid in April 2008. The remaining increase relates to the amortization of deferred financing costs associated with the revolving credit facility of our Partnership Credit Agreement and the issuance of Senior Notes in April 2008.

Non-controlling Interest in Net Loss (Income) of Consolidated Subsidiaries. The non-controlling interest in net loss (income) of consolidated subsidiaries decreased during the year ended December 31, 2008, relative to 2007, due to the fact that there was no longer a non-controlling interest in the Partnership after the Merger was completed on February 21, 2008. The 50% non-controlling interest in the earnings of Wirth Gathering, which was acquired in July 2008, is not material for the year ended December 31, 2008.

Provision for Income Tax. The total provision for income tax for the year ended December 31, 2008 was $68.8 million. Refer to Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for a discussion of the significant changes in the provision.

The current provision for income tax was $15.0 million for the year ended December 31, 2008. Approximately $13.5 million is attributable to MarkWest Hydrocarbon, Inc. Of this amount, $18.8 million is attributable to MarkWest Hydrocarbon's ownership of Class A units, and the remaining benefit of $5.3 million is related to the Corporation's NGL marketing business. The remaining $1.5 million is related to taxes payable by the Partnership associated with the Texas Margin tax and Michigan Business Taxes.

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

Southwest

	Year ended December 31,			
	2007	2006	$ Change	% Change
	(in thousands)			
Revenue	$503,461	$466,384	$ 37,077	8%
Operating expenses:				
Purchased product costs	310,888	329,154	(18,266)	(6)%
Facility expenses	44,045	29,204	14,841	51%
Total operating expenses before items not allocated to segments	354,933	358,358	(3,425)	(1)%
Operating income before items not allocated to segments	$148,528	$108,026	$ 40,502	37%

Revenue. Revenue increased during the year ended December 31, 2007, relative to 2006, due mainly to increased volumes and higher pricing in most areas of the Southwest segment. Revenue in East Texas increased $32.0 million as a result of 18.2 million additional NGL gallons sold and 35,600 Mcf/d increase in gathering system throughput. This increase was partially offset by a decrease in sales of natural gas due to an October 2006 change from a keep-whole arrangement to a processing contract at our Carthage facility. Revenue from our Oklahoma operations increased $22.3 million due primarily to the expansion of the Woodford gathering system, which had only one month of activity in the 2006 year. The acquisition of the Grimes gathering system also contributed to the increase in revenue.

The increase in revenue was partially offset by a decrease of $17.2 million from Other Southwest areas which is attributed to a late second quarter 2006 change in the contract mix (from purchasing contracts to gathering contracts) at our Appleby facility.

Purchased Product Costs. Purchased product costs decreased during the year ended December 31, 2007, relative to 2006. The decrease was mainly attributable to the contractual changes described above. The decrease was partially offset by gas purchases related to the operations of our Woodford gathering system which began operation in December 2006, and by increased average NGL pricing and additional NGL volumes purchased under percent-of-proceeds contracts for our East Texas operations.

Facility Expenses. Facility expenses increased during the year ended December 31, 2007, relative to 2006, due primarily to the $12.4 million increase resulting from the full year of operations in Woodford gathering system and acquisition of the Grimes gathering system described above. Expanded operations in East Texas and our Other Southwest areas also resulted in higher payroll costs and higher compression expenses.

Northeast

	Year ended December 31, 2007	Year ended December 31, 2006	$ Change	% Change
	(in thousands)			
Revenue	$265,152	$293,964	$(28,812)	(10)%
Operating expenses:				
Purchased product costs	177,004	231,443	(54,439)	(24)%
Facility expenses	16,347	17,009	(662)	(4)%
Total operating expenses before items not allocated to segments	193,351	248,452	(55,101)	(22)%
Operating income before items not allocated to segments	$ 71,801	$ 45,512	$ 26,289	58%

Revenue. Total revenue decreased during the year ended December 31, 2007, relative to 2006 primarily due to the cessation of our wholesale business which generated approximately $47.6 million of revenue in 2006 and zero in 2007. A significant decline in our natural gas marketing transactions also resulted in a $19.7 million decrease in revenue. These decreases were partially offset by a $38.5 million increase in revenue from our Appalachia processing operations. The increase in revenue is due primarily to higher NGL prices and an increase in the gallons sold.

Purchased Product Costs. Purchased product costs decreased during the year ended December 31, 2007, relative to 2006. Approximately $47.3 million of decrease is due to the cessation of our wholesale business, and $19.5 million of the decrease is related to the decline in our natural gas marketing transactions, as discussed above. These decreases were partially offset by a $12.4 million increase in from our Appalachia processing operations due mainly to increased volumes and higher prices for natural gas and NGLs.

Gulf Coast

	Year ended December 31, 2007	Year ended December 31, 2006	$ Change	% Change
	(in thousands)			
Revenue	$77,114	$68,950	$8,164	12%
Operating expenses:				
Facility expenses	10,471	11,190	(719)	(6)%
Total operating expenses before items not allocated to segments	10,471	11,190	(719)	(6)%
Operating income before items not allocated to segments	$66,643	$57,760	$8,883	15%

Revenue. Revenue increased 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 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 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 expense, costs related to our fourth quarter 2007 turnaround, and compressor repairs.

Reconciliation of Segment Operating Income to Consolidated Net Income (Loss) Before Non-Controlling Interest and Provision for Income Tax

The following table provides a reconciliation of revenue and operating income before items not allocated to segments to our consolidated net income (loss) before non-controlling interest and provision for income tax for the years ended December 31, 2007 and 2006. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

	Year ended December 31, 2007	Year ended December 31, 2006	$ Change	% Change
	(in thousands)			
Total segment revenue	$ 845,727	$829,298	$ 16,429	2%
Derivative (loss) gain not allocated to segments	(159,970)	10,383	(170,353)	(1,641)%
Total revenue	$ 685,757	$839,681	$(153,924)	(18)%
Operating income before items not allocated to segments	$ 286,972	$211,298	$ 75,674	36%
Derivative (loss) gain not allocated to segments	(175,148)	4,694	(179,842)	(3,831)%
Selling, general and administrative expenses	(72,484)	(63,360)	(9,124)	14%
Depreciation	(41,281)	(31,010)	(10,271)	33%
Amortization of intangible assets	(16,672)	(16,047)	(625)	4%
(Loss) gain on disposal of property, plant and equipment	(7,743)	322	(8,065)	(2,505)%
Accretion of asset retirement obligations	(114)	(102)	(12)	12%
Impairment of goodwill and long-lived assets	(356)	—	(356)	N/A
(Loss) income from operations	(26,826)	105,795	(132,621)	(125)%
Earnings from unconsolidated affiliates	5,309	5,316	(7)	(0)%
Interest income	4,547	1,574	2,973	189%
Interest expense	(39,435)	(40,942)	1,507	(4)%
Amortization of deferred financing costs and discount (a component of interest expense)	(2,983)	(9,229)	6,246	(68)%
Miscellaneous income	233	11,984	(11,751)	(98)%
(Loss) income before non-controlling interest in net income of consolidated subsidiaries and provision for income tax	$ (59,155)	$ 74,498	$(133,653)	(179)%

Derivative (Loss) Gain. Derivative losses were $175.1 million for the year ended December 31, 2007, compared to derivative gains of $4.7 million for the year ended December 31, 2006. The change of $179.8 million is primarily attributable to the significant increase in crude oil prices during 2007 relative to the prices when the derivative contracts were executed. Approximately $154.9 million of the change relates to unrealized losses due to mark-to-market adjustments. Settlements of our derivative instruments resulted in a $24.9 million increase in realized losses, when comparing 2007 to 2006 results.

Selling, General and Administrative Expenses. Selling, general and administrative expenses increased during the year ended December 31, 2007, relative to 2006. We incurred $6.4 million due to Merger-related activities in 2007. We also incurred an additional $4.3 million of labor, benefits and related office expenses due to our expansion initiatives. In addition, we incurred a one-time charge in 2006 to terminate the old headquarters lease of $0.8 million. These increases were offset by a $2.2 million reduction in stock-based compensation expense related primarily to the Participation Plan.

Depreciation. Depreciation increased during the year ended December 31, 2007, relative to 2006, due primarily to the increased asset base resulting from the acquisitions and expansion projects completed during 2006 and 2007.

Impairment of Goodwill and Long-Lived Assets. 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 11 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

(Loss) Gain on Disposal of Property, Plant and Equipment. Loss from disposal of property, plant and equipment increased 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 during the year ended December 31, 2007, relative to 2006, primarily due to the proceeds received from a rate case concluded in the first quarter of 2007 in our Gulf Coast segment.

Amortization of Deferred Finance Costs. The amortization related to deferred finance costs decreased during the year ended December 31, 2007, relative to 2006. The decrease is attributable to the write-off of deferred financing costs associated with our debt refinancing in the third quarter of 2006.

Miscellaneous Income. Miscellaneous income decreased during the year ended December 31, 2007, relative to 2006. This decrease was largely a result of a change in insurance recoveries related to our investment in Starfish.

Liquidity and Capital Resources

Our primary strategy is to expand our asset base through organic growth and expansion projects and selective third-party acquisitions that are accretive to our cash available for distribution per common unit. In 2008, we spent approximately $638.6 million on internal development and expansion opportunities. In 2008, we completed two third-party acquisitions and the Merger with MarkWest Hydrocarbon.

As a result of the recently announced joint venture agreement with NGP Midstream & Resources, L.P. ("M&R") and the expansion of our credit facility we have significantly improved our liquidity position (see Note 26 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K and *Matters Impacting Future Results* for further details of the joint venture agreement and the expansion of our credit facility). Our 2009 capital plan includes approximately $400 million of capital expenditures for board-approved growth projects, plus $5 million to $10 million for maintenance capital. Approximately $200 million of the 2009 capital plan relates to projects included within the joint venture. In accordance with the joint venture agreement, M&R will make contributions of $200 million, offsetting our cash requirements. Therefore, our net cash requirement for the 2009 capital plan is approximately $200 million. Growth capital includes expenditures made to expand the existing operating capacity, increase the efficiency of our existing assets, costs associated with new well connections or facilitate an increase in volumes within our operations. Maintenance capital includes capital expenditures made to maintain our operating capacity and asset base. In addition to the planned capital expenditures in 2009, we expect to receive capital calls of approximately $4 million to $6 million within our Starfish joint venture for the cost to repair damages to the onshore and offshore facilities caused by Hurricane Ike. We expect to file insurance claims and recover a portion of those costs (see further discussion in the *Matters Impacting Future Results*).

Our primary sources of liquidity to meet operating expenses, pay distributions to our unitholders and fund capital expenditures are cash flows generated by our operations and access to debt and equity markets, both public and private. All expenditures on board-approved 2009 capital projects will be funded with cash flow from operations, current cash balances, contributions by our joint venture partner for capital projects encompassed by the joint venture and our current borrowing capacity under our recently expanded revolving credit facility. We will also consider the use of alternative financing strategies such as entering into additional joint venture arrangements and the sale of non-strategic assets. However, we believe that it would be necessary to raise additional capital in order to finance additional growth projects beyond those that are currently approved by the board. Neither management nor the board of directors would approve any incremental projects unless we determine that we could raise the necessary capital.

On February 20, 2008, we entered into the Partnership Credit Agreement consisting of a $350.0 million revolving credit facility and a $225.0 million term loan, each of which has a five-year term. In connection with the Merger, we initially borrowed the entire $225.0 million under the term loan. In addition, we borrowed $84.0 million under the revolving credit facility in connection with the refinancing of our prior credit facility. The Partnership Credit Agreement limits our ability to enter into transactions with parties that require margin calls under certain derivative instruments. The Partnership Credit Agreement prevents members of the participating bank group from requiring margin calls. As of February 23, 2009 approximately 87% of our derivative positions, measured volumetrically, are with members of the participating bank group. We believe this arrangement gives us additional liquidity as it allows us to enter into derivative instruments without utilizing cash for margin calls or requiring the use of letters of credit; however, there is no certainty that the members of our bank group will continue to participate and in such case, a portion of our available credit could be used for derivative instruments instead of future growth.

On April 15, 2008, we completed a private placement of $400.0 million in aggregate principal amount of 8.75% senior notes due 2018 to qualified institutional buyers under Rule 144A (the "2018 Notes"). On May 1, 2008, we completed a follow-on offering of $100.0 million under the indenture of the 2018 Notes. These notes mature on April 15, 2018.

Effective March 2, 2009, the revolving credit facility was amended in order to accommodate the joint venture with M&R and expanded to $435.6 million to provide additional liquidity. Under the terms of the amendment, the accordion feature remains at $200.0 million of uncommitted funds. The term of the original credit agreement has been reduced by one year and will now be due on February 20, 2012. Under the provisions of the Partnership Credit Agreement we are subject to a number of restrictions and covenants as defined by the agreement. These covenants are used to calculate the available borrowing capacity on a quarterly basis. As of February 23, 2009, we had $265.1 million of borrowings outstanding under the revolving credit facility and had $45.5 million available for borrowing, with $39.4 million of letters of credit outstanding. As a result of the closing of the joint venture transaction and the amendment to our credit facility, we expect to have an available borrowing capacity of approximately $160.0 million as of March 2, 2009.

In addition to the 2018 Senior Notes, the Partnership, in conjunction with MarkWest Energy Finance Corporation, has two other series of senior notes outstanding as of December 31, 2008; $225.0 million aggregate principal maturing in November 2014 (the "2014 Senior Notes"), and $275.0 million aggregate principal due in July 2016 (the "2016 Senior Notes" and all together with the 2014 Senior Notes and 2018 Senior Notes, the "Senior Notes"). For further discussion of the Senior Notes see Note 15 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

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

In the future, we may raise additional capital through the issuance of debt and equity securities under our shelf registration statement or in private transactions.

The unprecedented level of uncertainty that currently exists in the financial markets has created an increased risk of counterparty default that could impact our liquidity in several ways. During 2009, we expect that we will be required to borrow additional amounts under our revolving credit facility. However, our ability to access these funds could be adversely impacted by the failure of one or more of the members of the participating bank group. Although management believes that the participating members are financially sound, an increased risk does exist. Also, because the participating members of our bank group are the counterparties to most of our derivative instruments, the failure of one of more members could significantly reduce the cash flow from operations related to the settlement of these positions. The cash flows generated by our operations could also be significantly reduced if any of our major customers defaulted. The credit worthiness of our trade customers is continuously monitored, and we believe that our current group of customers are sound and represent no abnormal credit risk.

Our ability to pay distributions to our unitholders and to fund planned capital expenditures and make acquisitions will depend upon our future operating performance. That, in turn, 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. The current global economic uncertainty has had a significant adverse impact on the availability of capital funding. Additionally, commodity prices have remained at depressed levels since the end of 2008. Our future operating performance could be negatively impacted if these conditions do not improve or continue to deteriorate.

Cash Flow

	Year ended December 31,	
	2008	2007
Net cash provided by operating activities	$ 226,995	$ 133,237
Net cash used in investing activities	(909,265)	(314,792)
Net cash provided by financing activities	647,896	170,406

Net cash provided by operating activities increased $93.8 million during the year ended December 31, 2008, compared to 2007. The increase was primarily due to an increase in operating income, excluding unrealized derivative gains and losses, in the Southwest and Gulf Coast segments, and return of margin deposits held as of December 31, 2007 of $40.3 million, offset by premiums paid for derivative instruments of $13.4 million. The early settlement of the 2010 and 2011 derivative positions during the fourth quarter also contributed approximately $24.7 million to operating cash flow, net of current income tax expense. Our other operating activities used net cash of approximately $13.9 million in the fourth quarter. This is due to the decline in the prices of NGLS and the adverse change in the correlation between NGL and crude oil prices.

Net cash used in investing activities increased $594.5 million for the year ended December 31, 2008, compared to 2007. The increase was primarily due to cash paid as consideration in the Merger of $269.9 million, including $21.5 million paid to acquire the General Partner's minority interest. Additional increases were due to increased capital expenditures primarily from our organic growth projects, where we spent approximately $638.6 million of expansion capital, including equity investments and the acquisition of PQ Assets in 2008.

Net cash provided by financing activities increased $477.5 million for the year ended December 31, 2008, compared to 2007. The increase was primarily due to the $488.5 million of proceeds from the 2018 Notes, $129.2 million of net borrowings on the revolving credit facility and $171.4 million in proceeds from a public equity offering. The cash provided by these financing activities was used primarily to fund the cost of the Merger and to raise funds for capital expenditures.

On April 15, 2008, we completed a private placement of the 2018 Notes. We received net proceeds of approximately $388.1 million, after deducting initial purchasers' discounts and the estimated expenses of the offering. On May 1, 2008, we completed a follow-on offering of $100.0 million under the indenture of the 2018 Notes. We received net proceeds of $100.4 million, after including the initial purchasers' premium and the estimated expenses of the offering.

On April 14, 2008, we completed a public offering of 5.75 million newly issued common units, including overallotments, representing limited partner interests at a purchase price of $31.15 per common unit. The net proceeds were approximately $171.4 million.

On December 18, 2007, MarkWest Energy Partners completed a private placement of 2.9 million unregistered common units, which we subsequently registered. The units were issued at a purchase price of $31.50 per unit. The sale of units raised net proceeds of approximately $90.0 million after legal, accounting and other transaction expenses.

On April 9, 2007, MarkWest Energy Partners completed a private placement of 4.1 million unregistered common units, which we subsequently registered. The units were issued at a purchase price of $32.98 per unit. The sale of units raised net proceeds of approximately $135.0 million after legal, accounting and other transaction expenses.

Distributions and dividends increased $51.3 million for the year ended December 31, 2008, compared to 2007, due to an increase in the number of units outstanding and increase in the declared distribution per unit. The number of units increased due to the Merger and the offering completed in April 2008. The declared distribution per unit increased as a result of the elimination of incentive distribution rights and increased cash generated from operations.

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of December 31, 2008, is as follows (in thousands):

	Payment Due by Period				
Type of obligation	**Total Obligation**	**Due in 2009**	**Due in 2010 - 2011**	**Due in 2012 - 2013**	**Thereafter**
Long-term debt	$1,184,700	$ —	$ —	$184,700	$1,000,000
Interest expense on long-term debt(1)	713,672	91,367	182,734	175,423	264,148
Operating leases(2)	21,237	8,148	4,691	3,847	4,551
Purchase obligations(3)	111,210	111,210	—	—	—
Other long-term liabilities reflected on the Consolidated Balance Sheets:					
Asset retirement obligation(4)	1,773	—	—	—	1,773
Other(5)	3,705	—	2,530	733	442
Total contractual cash obligations	$2,036,297	$210,725	$189,955	$364,703	$1,270,914

(1) Assumes that our outstanding borrowings at December 31, 2008 remain outstanding until their respective maturity dates and we incur interest expense at 4.75% on the Partnership Credit Facility

revolver, 6.875% on the 2014 Senior Notes, 8.5% on the 2016 Senior Notes and 8.75% on the 2018 Senior Notes.

(2) Amounts relate primarily to compressor rentals and our office leases.

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

(4) Excludes accretion expense of $6.7 million. The total amount to be paid is approximately $8.5 million.

(5) Primarily represents long-term portion of deferred revenue. We had approximately $0.4 million of tax contingencies related to FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, as of December 31, 2008. Based on the uncertainty of the timing of these contingencies, these amounts have not been included in the table above.

Off-Balance Sheet Arrangements

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

Matters Impacting Future Results

In the fourth quarter of 2007, we announced the expansion of the Javelina plant which has an expected cost of $112.7 million. This expansion involves the installation of a steam methane reformer facility ("SMR") 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. As of December 31, 2008, we have spent $54.8 million on the SMR and expect to spend an additional $57.9 million to complete the project in 2009.

As discussed in Note 17 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K, the Partnership acquired all of the outstanding interests in the General Partner. 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. In the future, our results will not include compensation for the general partner interests under the Participation Plan. For the years ended December 31, 2008, 2007 and 2006, our results include compensation expense of $5.5 million, $17.7 million and $20.7 million, respectively, related to the Participation Plan.

The 2008 LTIP reserves 2.5 million common units for issuance in the future. As discussed further in Note 17 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. An additional 7,500 and 257,500 phantom units were granted in April 2008 and January 2009, respectively, under the same arrangement. The amount of compensation expense related to these grants will range from $10.7 million to $26.7 million, assuming no forfeitures. 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. Compensation expense recorded for the performance-based units expected to vest was approximately $4.1 million for the year ended December 31, 2008. The timing of the remainder of the expense, if any, cannot be estimated.

In December 2008, our affiliate, MarkWest Pioneer, L.L.C., commenced construction of a new interstate natural gas transmission pipeline, the Arkoma Connector Pipeline, that will extend approximately 50 miles from an interconnect with our gathering system in the Woodford Shale production area in Southeast Oklahoma to an interconnect with the Midcontinent Express Pipeline and with the Gulf Crossing Pipeline in Bennington, Oklahoma.

The Arkoma Connector Pipeline will provide additional outlets for producers in the Woodford Shale as volumes continue to increase. Executed agreements are in place with certain producers to provide transportation capacity in excess of 600 MMcf/d on the Arkoma Connector Pipeline.

In June 2008, we announced an agreement with Range to construct and operate natural gas gathering pipelines and processing facilities associated with Range's Marcellus Shale acreage in the Appalachian Basin. Our services under this agreement are primarily percent-of-proceeds arrangements. During 2008 we began operations under this agreement utilizing an interim processing facility. By the end of 2009, we expect to complete two permanent cryogenic processing facilities: a 30 MMcf/d processing facility and a 120 MMcf/d processing facility. During 2008, the results of operations related to these assets were immaterial to the Partnership's consolidated financial results. As noted above, on February 27, 2009, we executed an agreement to contribute all of our assets related to these operations to a joint venture with M&R. The joint venture is owned 60% by MarkWest and 40% by M&R, and we will operate the joint venture.

In July 2008, we acquired PQ Gathering Assets, L.L.C., a subsidiary of PetroQuest that owns natural gas gathering assets located primarily in Pittsburg County in Southeast Oklahoma for $41.3 million. The acquisition also includes a 50% controlling operating interest in Wirth Gathering, a general partnership. These gathering systems currently support approximately 60 MMcf/d of natural gas wells. The PetroQuest natural gas gathering assets are located adjacent to, and have been fully integrated with, our existing Woodford Shale operations. Our contracts for these systems are primarily fee-based arrangements. We recognized approximately $3.4 million in revenue from these systems during 2008 since the date of acquisition.

In August 2008, we announced our intention to jointly develop several natural gas gathering and processing projects with Columbia Gas, a division of NiSource Inc., to support increased production volumes in the northern West Virginia and Western Pennsylvania areas of the Appalachian Basin. MarkWest and Columbia Gas are in discussions with several interested natural gas producers to provide new gathering and gas processing services in association with Columbia Gas' existing Majorsville, West Virginia compressor station. Several existing Columbia pipelines in Washington and Greene counties in Pennsylvania and Marshall and Wetzel counties in West Virginia are available to serve as the backbone of the gathering system connecting with our proposed processing plant at Majorsville. We could begin processing a portion of the production from these pipelines in the third quarter 2009 and may increase volumes during 2009 and 2010.

In October 2008, we announced our intention, in collaboration with Columbia, to jointly expand natural gas gathering and processing services to support the increased production volumes in the Appalachian Basin of central West Virginia. Columbia and MarkWest are in discussions with several natural gas producers regarding plans to provide new gathering and processing services near Columbia Gas' Cobb aggregation system in Kanawha, Jackson and Roane counties of West Virginia. The additional volumes will be processed at our existing Cobb processing facility, and the recovered liquids will be fractionated at our existing Siloam facility.

In September 2008, Hurricane Ike caused wind and water damage to oil and gas assets in the Gulf of Mexico and Gulf Coast regions, including damage to several onshore and offshore facilities of Starfish, our unconsolidated affiliate. Due to the damage in the region, the operations of Starfish have been partially curtailed since the hurricane impacted the area. Until necessary repairs are completed, Starfish may not be able to fully return to normal operations, which will have a continuing impact on our net income. We contributed $5 million in cash for hurricane repair in 2008 and we estimate we may have to contribute an additional $4 million to $6 million. The determination of the full effect of the hurricane is subject to a number of factors including ongoing damage assessments, disclosures by operators of interconnecting production and processing facilities, and discussions with insurance carriers for insurance recovery for damages and business interruption. Along with other industry participants, we have seen our insurance costs increase substantially within this region as a result of these developments. 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 fully insured. 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.

Effects of Inflation

Inflation did not have a material impact on our results of operations for the years ended December 31, 2008, 2007 or 2006. 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 inventory; valuing identified intangible assets; evaluating impairments of long-lived assets, goodwill and equity investments; 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.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Inventories		
Inventories, which consist primarily of natural gas, propane, and other NGLs, are recorded at the lower of weighted-average cost or market value.	Due to the short-term volatility in commodity prices and differences based on geographic location, judgment is required in determining the market value of inventory. We estimate the market value based on the expected sales prices during the periods in which inventory will be sold.	As a result of the lower of cost or market analysis performed at December 31, 2008, we recorded expense of $6.7 million to write down inventories to market value. If the actual sales prices are 10% lower than the expected prices used in our analysis, net income before taxes would have been reduced by approximately $0.7 million.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
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.	The fair value of customer contracts is generally calculated using the income approach in accordance with SFAS 157 and FASB Concept Statement 7, Using Cash Flow Information and Present Value in Accounting Measurements ("Concept Statement 7"). 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.	If the actual results differ significantly from the assumptions used to determine the fair value and economic lives of intangible assets, then a significant impairment charge could be recorded. (See Impairment of Long-Lived Assets below.)

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Long-Lived Assets		
Management evaluates the Partnership's 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.	Management considers the volume of reserves behind the asset and future NGL product and natural gas prices to estimate cash flows for each asset group. The amount of additional reserves developed by future drilling activity depends, in part, on expected commodity prices. Projections of reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast.	A significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset. A 10% decrease in the estimated future cash flows used in our impairment analysis would have indicated a potential impairment for two asset groups with a total net book value of $11.8 million. During 2008 we recorded an impairment on our gas gathering assets in Western Michigan. We used the market approach to determine the assets' fair value and recorded an impairment of $7.6 million. If the assumptions used to determine the fair value of the assets differ from actual results, we could be required to recognize an additional impairment of up to $0.5 million, which is the full net book value of these assets at December 31, 2008.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Goodwill		
Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We evaluate goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.	Management determines the fair value of our reporting units using the income and market approaches outlined in SFAS 157 and Concept Statement 7. These approaches are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors such as relevant commodity prices and production volumes. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations. Management was also required to make certain assumptions when identifying the reporting units and determining the amount of goodwill allocated to each reporting unit. The method of allocating goodwill resulting from the Merger involved estimating the fair value of the reporting units and allocating the purchase price of the Merger to each reporting unit. Goodwill was then calculated for each reporting unit as the excess of the allocated purchase price over the estimated fair value of the net assets.	As a result of the goodwill impairment testing completed in 2008, we recorded impairment expense of $28.7 million. A significant variance in any of the assumptions used in the analysis could lead to additional future impairments. If the estimated fair values used in our impairment test were reduced by 10%, there would have been no additional impairment in 2008. The remaining goodwill balance is $9.4 million as of December 31, 2008. Although management believes that the methodology used to allocate goodwill to the reporting units was reasonable and applied consistently, a significant change in these allocations could have resulted in material change in the impairment expense recorded in 2008.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Equity Investments		
We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of an other-than-temporary loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred.	Our impairment loss calculations require management to apply judgment in estimating future cash flows and asset fair values, including forecasting useful lives of the assets, assessing the probability of differing estimated outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models.	Due to significant capital calls to fund the damage repairs related to Hurricane Ike and reductions in the expected future cash distributions from Starfish, management determined that our investment in Starfish must be evaluated for impairment as of December 31, 2008. Using the impairment review methodology described herein, we have recorded an impairment charge of \$41.4 million. If the estimated fair value of our investment in Starfish was reduced by 10%, then an additional impairment charge of \$1.7 million would have been recorded. The carrying value of our investment in Starfish investments as of December 31, 2008 was \$17.2 million. Management determined that there were no material events or changes in circumstances that would indicate an other-than-temporary decline in value of our investment in Centrahoma.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Accounting for Share-Based Compensation		
Our long-term incentive plans permit the grant of restricted units, phantom units, unit options and substitute awards. As of December 31, 2008, only phantom units are issued and outstanding under these plans. Compensation expense is recognized over the vesting period or service period of the related awards. Compensation expense is only recognized for those awards for which vesting is probable. The vesting of performance-based awards is contingent upon the Partnership meeting specific financial targets in fiscal year 2008, 2009 and 2010.	We must exercise judgment and make several assumptions regarding the future profits and cash flows of the Partnership in order to estimate the number of performance-based units for which vesting is probable.	During the fiscal year ended December 31, 2008, management expected all of the performance-based awards related to fiscal year 2008 performance to vest and recorded compensation expense accordingly. Management concluded that the vesting of the awards based on 2009 and 2010 performance was not probable. If management had concluded that vesting of the 2009 performance awards was probable, an additional \$2.0 million of compensation expense would have been recognized during the year ended December 31, 2008. If management had concluded that vesting of the 2009 and 2010 performance awards was probable, an additional \$3.3 million of compensation expense would have been recognized during the year ended December 31, 2008.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Accounting for Risk Management Activities and Derivative Financial Instruments		
Our derivative financial instruments are recorded at fair value in the accompanying Consolidated Balance Sheets. Changes in fair value are reflected in the Partnership's earnings in the accompanying Consolidated Statements of Operations as unrealized gains and losses until the instrument is settled. Upon settlement, the gains and losses are classified as realized.	When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument's fair value. The valuation of certain financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based on inputs that are largely unobservable. These instruments are classified as Level 3 under SFAS 157. The fair value of these instruments are determined based on pricing models developed primarily from historical and expected correlations with quoted market prices considering credit and nonperformance risk.	If the assumptions used in the pricing models for our Level 2 and 3 financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains that could be material. A 10% difference in our estimated fair value of Level 2 and 3 derivatives at December 31, 2008 would have affected net income by approximately $23.5 million for the year ended December 31, 2008.

Recent Accounting Pronouncements

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

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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 or purchases of natural gas, NGLs and crude oil. Swaps and futures contracts may allow us to reduce downside volatility in our 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 risk management activity and continually monitors the risk management program and expects to continue to adjust our financial positions as conditions warrant.

To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have primarily entered into derivative financial instruments relating to the future price of crude oil. To mitigate our cash flow exposure to fluctuations in the price of natural gas, we primarily utilize derivative financial instruments relating to the future price of natural gas. As a result of these transactions, we have mitigated a portion of our expected commodity price risk with agreements primarily expiring at various times through the fourth quarter of 2011.

We utilize a combination of futures contracts, fixed-price forward contracts, fixed-for-floating price swaps and options on the over-the-counter ("OTC") market. These types of 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 may enter into physical and/or financial positions to manage the risks related to commodity price exposure for our marketing activities. Due to the timing of purchases and sales, direct exposure to price volatility may result because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Through marketing and derivative activities, direct price exposure may occur naturally or we may choose direct exposure when it is favorable as compared to the keep-whole risk.

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. The Partnership Credit Agreement limits our ability to enter into transactions with parties that require margin calls under certain derivative instruments. The Partnership Credit Agreement prevents members of the participating bank group from requiring margin calls. As of February 23, 2009 approximately 87% of our derivative positions, measured volumetrically, are with members of the participating bank group. We may be subject to margin deposit requirements under OTC agreements (with non-bank counterparties) 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 terminate the corresponding futures contracts.

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, potentially 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.

The following tables provide information on our specific derivative positions related to long liquids and keep-whole positions at December 31, 2008, including the weighted average prices ("WAVG"). The tables do not include the positions settled in January and February 2009 as discussed below.

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)	Fair Value (in thousands)
2009	3,425	$67.50	$77.83	$17,831
2010 (Apr - Dec)	1,297	66.48	74.49	1,694

WTI Crude Puts	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	Fair Value (in thousands)
2009	2,413	$80.00	$24,632
2010	1,191	80.00	9,529
2011	1,818	80.00	12,800

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2009	1,454	$119.50	$33,826
2010 (Jan - Sep)	1,030	66.11	1,116

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2009	9,770	$8.38	$(12,238)

The following tables provide information on the specific derivative positions related to keep-whole positions of our taxable subsidiary at December 31, 2008, including the WAVG. The tables do not include the positions settled in January and February 2009 as discussed below.

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2009	3,374	$66.02	$14,071
2010	2,428	70.25	6,201
2011	3,027	87.66	20,283
2012 (Jan)	2,142	91.50	1,342

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2009	16,122	$8.20	$(10,760)
2010	10,806	8.41	(4,572)
2011	14,662	8.88	(7,396)

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2009 (Jan - Mar)	19,636	$1.94	$2,088

Iso Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2009 (Jan - Mar)	6,727	$1.98	$709

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2009 (Jan - Mar)	13,151	$2.51	$2,022

We have 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 No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133"), the value of this contract is marked based on an index price through purchased product costs. As of December 31, 2008, the estimated fair value of this contract was $0.6 million.

We have 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, the value of the derivative component of this contract is marked to market through facilities expense. As of December 31, 2008, the estimated fair value of this contract was $(0.6) million.

In January and February 2009, we settled a portion of our derivative positions covering 2009, 2010 and 2011 for $15.2 million of net gains. The settlement was completed prior to the contractual settlement to improve liquidity and to mitigate credit risk with certain counterparties, and as such does not represent trading activity. $26.5 million of realized gains will be included in Realized (loss) gain—revenue and $11.3 million loss will be included in Realized gain (loss)—purchased product costs. At December 31, 2008, the fair value of the subsequently settled positions was $16.7 million.

The following table provides information on the derivative positions that we have entered into subsequent to December 31, 2008.

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)
2010	778	$57.48

Interest Rate

Our primary interest rate risk exposure results from the revolving portion of the Partnership Credit Agreement that has a borrowing capacity of $435.6 million and was entered into on February 20, 2008, and amended on March 2, 2009. As of February 23, 2009, we have $265.1 million outstanding borrowings on the revolving credit facility. The debt related to this agreement bears interest at variable rates that are tied to either the U.S. prime rate or LIBOR at the time of borrowing. We may make use of interest rate swap agreements in the future, to adjust the ratio of fixed and floating rates in our debt portfolio.

Long-Term Debt	Interest Rate	Lending Limit	Due Date	Outstanding at December 31, 2008
Partnership Credit Agreement	Variable	$435.6 million	February 2012	$184.7 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
2018 Senior Notes	Fixed	$500.0 million	April 2018	$500.0 million

Based on our overall interest rate exposure at December 31, 2008, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our credit facility would change earnings by approximately $1.8 million over a 12-month period. Based on our overall interest rate exposure at February 23, 2009, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our credit facility would change earnings by approximately $2.7 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, 2008 and 2007, and the related consolidated statements of operations, changes in partners' capital and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 March 2, 2009 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
March 2, 2009

MARKWEST ENERGY PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,321	$ 37,695
Trading securities	—	3,674
Available for sale securities	—	6,474
Receivables, net of allowances of $175 and $194, respectively	101,849	130,877
Inventories	31,556	30,328
Fair value of derivative instruments	126,949	9,441
Deferred income taxes	—	16,667
Other current assets	11,748	51,178
Total current assets	275,423	286,334
Property, plant and equipment	1,650,692	976,169
Less: accumulated depreciation	(81,167)	(145,360)
Total property, plant and equipment, net	1,569,525	830,809
Other long-term assets:		
Investment in unconsolidated affiliates	46,092	58,709
Intangibles, net of accumulated amortization of $42,972 and $45,753, respectively	695,917	326,722
Goodwill	9,421	—
Deferred financing costs, net of accumulated amortization of $3,248 and $8,206, respectively	16,682	13,428
Deferred contract cost, net of accumulated amortization of $1,326 and $1,014, respectively	1,924	2,236
Fair value of derivative instruments	55,389	5,414
Other long-term assets	2,681	1,043
Total other long-term assets	828,106	407,552
Total assets	$2,673,054	$1,524,695
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 72,837	$ 107,107
Accrued liabilities	111,034	79,869
Deferred income taxes	2,682	—
Fair value of derivative instruments	37,633	77,426
Total current liabilities	224,186	264,402
Deferred income taxes	47,465	8,500
Fair value of derivative instruments	14,801	84,051
Long-term debt, net of discounts of $11,735 and $2,805, respectively	1,172,965	552,695
Other long-term liabilities	5,878	51,073
Non-controlling interest in consolidated subsidiaries	3,301	524,583
Commitments and contingencies (see Note 22)		
Partners' Capital:		
Common units, 56,640 and 22,861 units outstanding, respectively	1,204,458	38,463
Accumulated other comprehensive income, net of tax	—	928
Total partners' capital	1,204,458	39,391
Total liabilities and partners' capital	$2,673,054	$1,524,695

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,		
	2008	2007	2006
Revenue:			
Revenue	$1,060,662	$ 845,727	$829,298
Derivative gain (loss)	277,828	(159,970)	10,383
Total revenue	1,338,490	685,757	839,681
Operating expenses:			
Purchased product costs	615,902	487,892	560,597
Derivative loss related to purchased product costs	22,371	15,192	5,689
Facility expenses	103,682	70,863	57,403
Derivative loss (gain) related to facility expenses	644	(14)	—
Selling, general and administrative expenses	68,975	72,484	63,360
Depreciation	67,480	41,281	31,010
Amortization of intangible assets	38,483	16,672	16,047
Loss (gain) on disposal of property, plant and equipment	178	7,743	(322)
Accretion of asset retirement obligations	129	114	102
Impairment of goodwill and long-lived assets	36,351	356	—
Total operating expenses	954,195	712,583	733,886
Income (loss) from operations	384,295	(26,826)	105,795
Other income (expense):			
Earnings from unconsolidated affiliates	90	5,309	5,316
Impairment of unconsolidated affiliate	(41,449)	—	—
Interest income	3,769	4,547	1,574
Interest expense	(64,563)	(39,435)	(40,942)
Amortization of deferred financing costs and discount (a component of interest expense)	(8,299)	(2,983)	(9,229)
Miscellaneous (expense) income	(241)	233	11,984
Income (loss) before non-controlling interest in net income of consolidated subsidiaries and provision for income tax	273,602	(59,155)	74,498
Non-controlling interest in net loss (income) of consolidated subsidiaries	3,301	(4,853)	(59,709)
Income (loss) before provision for income tax	276,903	(64,008)	14,789
Provision for income tax expense (benefit):			
Current	15,032	23,869	(179)
Deferred	53,798	(48,518)	5,431
Total provision for income tax	68,830	(24,649)	5,252
Net income (loss)	$ 208,073	$ (39,359)	$ 9,537
Net income (loss) per common unit(1) (see Note 21):			
Basic	$ 4.08	$ (1.72)	$ 0.42
Diluted	$ 4.04	$ (1.72)	$ 0.42
Weighted average number of outstanding common units(1):			
Basic	51,013	22,854	22,745
Diluted	51,560	22,854	22,924
Cash distribution declared per common unit(1)	$ 2.059	$ 0.703	$ 0.416

(1) All unit and per unit data where applicable has been adjusted to reflect the Exchange Ratio to give effect to the Merger (see Note 3).

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

MARKWEST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL AND COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Common Units(1)	Partners' Capital	Accumulated Other Comprehensive Income	Total
December 31, 2005	22,646	$ 39,625	$ 357	$ 39,982
Stock option exercises	74	290	—	290
Compensation expense related to equity-based awards	—	401	—	401
Issuance of restricted stock	88	—	—	—
Treasury stock reacquired	(6)	—	—	—
Cashless stock options exercises	11	21	—	21
Reclassification of unearned compensation related to the adoption of SFAS 123R	—	—	—	—
APIC pool for excess tax benefits under SFAS 123R	—	177	—	177
Dividends paid	—	(9,665)	—	(9,665)
Net income	—	9,537	—	9,537
Unrealized gain on marketable securities, net of tax of $454	—		746	746
Comprehensive income				10,283
December 31, 2006	22,813	40,386	1,103	41,489
Stock option exercises	17	119	—	119
Compensation expense related to restricted stock, net of registration costs	—	753	—	753
Issuance of restricted stock	31	—	—	—
Gain in connection with issuance of units by MarkWest Energy Partners, L.P. (net of tax of $31.5 million)	—	52,367	—	52,367
APIC pool for excess tax benefits under SFAS 123R	—	335	—	335
FIN 48 adjustment	—	(71)	—	(71)
Dividends paid	—	(16,067)	—	(16,067)
Net loss	—	(39,359)	—	(39,359)
Unrealized loss on marketable securities, net of tax of $110	—	—	(175)	(175)
Comprehensive loss	—	—	—	(39,534)
December 31, 2007	22,861	38,463	928	39,391
Option exercises	98	375	—	375
Common units issued for vested phantom units	14	63	—	63
Dividends paid	—	(4,338)	—	(4,338)
Distributions paid	—	(107,269)	—	(107,269)
Share-based compensation related to equity awards	—	11,497	—	11,497
APIC pool for excess tax benefits under SFAS 123R	—	717	—	717
Merger and Redemption:				
Redemption of MarkWest Hydrocarbon, Inc. common stock	(7,458)	(240,513)	—	(240,513)
Conversion of restricted stock to phantom units in connection with the Merger	(45)	—	—	—
Acquisition of General Partnership's minority interest associated with the Merger	946	30,078	—	30,078
Purchase of minority interest of MarkWest Energy Partners, L.P.	34,474	1,095,917	—	1,095,917
Issuance of units in public offering, net of offering costs	5,750	171,395	—	171,395
Net income	—	208,073	—	208,073
Realized gain on marketable securities, net of tax of $558	—	—	(928)	(928)
Comprehensive income	—	—	—	207,145
December 31, 2008	56,640	$1,204,458	$ —	$1,204,458

(1) All unit data, including treasury stock, where applicable has been adjusted to reflect the Exchange Ratio to give effect to the Merger (see Note 3).

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

MARKWEST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year ended December 31,		
	2008	2007	2006
Cash flows from operating activities:			
Net income (loss)	$ 208,073	$ (39,359)	$ 9,537
Adjustments to reconcile net income (loss) to net cash provided by operating activities (net of acquisitions):			
Depreciation	67,480	41,281	31,010
Amortization of intangible assets	38,483	16,672	16,047
Impairment of goodwill and long-lived assets	36,351	356	—
Impairment of unconsolidated affiliate	41,449	—	—
Inventory lower of cost or market adjustment	6,678	—	—
Amortization of deferred financing costs and discount	8,299	2,983	9,229
Accretion of asset retirement obligations	129	114	102
Amortization of deferred contract costs	312	312	312
Phantom unit compensation expense	11,348	2,080	1,686
Participation Plan compensation expense	4,545	17,704	20,743
Stock option compensation expense	—	(27)	(9)
Restricted stock compensation expense	75	780	410
Non-controlling interest in net (loss) income of consolidated subsidiaries	(3,301)	4,853	59,709
Equity in earnings of unconsolidated affiliates	(90)	(5,309)	(5,316)
Distributions from unconsolidated affiliates	445	10,840	—
Unrealized (gain) loss on derivative instruments	(276,526)	150,418	(4,524)
Loss (gain) on disposal of property, plant and equipment	178	7,743	(332)
Deferred income taxes	53,798	(48,518)	5,431
Gain on sale of available for sale securities	(1,238)	(668)	(267)
Unrealized loss on trading securities	—	24	—
Loss (gain) on sale of trading securities	762	(14)	—
Net sales (purchases) of trading securities	2,400	(3,684)	—
Other	181	(190)	26
Changes in operating assets and liabilities, net of working capital acquired:			
Receivables	29,028	(29,761)	31,153
Inventories	(7,906)	4,451	5,806
Other current assets	39,430	(35,057)	333
Accounts payable and accrued liabilities	(34,072)	34,051	(14,653)
Notes receivable from officers	—	—	154
Other long-term assets	(1,126)	—	—
Other long-term liabilities	1,810	1,162	(618)
Net cash provided by operating activities	226,995	133,237	165,969

MARKWEST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(in thousands)

	Year ended December 31,		
	2008	2007	2006
Cash flows from investing activities:			
Acquisitions	(41,300)	29	(21,389)
Equity investments	(29,187)	—	(21,237)
Cash paid to acquire General Partnership's minority interest	(21,484)	—	—
Cash paid in Merger for MarkWest Hydrocarbon, Inc. stock	(248,395)	—	—
Purchase of available for sale securities	—	—	(789)
Proceeds from sale of available for sale securities	6,226	1,622	614
Capital expenditures	(575,298)	(316,639)	(80,080)
Proceeds from sale of equity investee	—	—	150
Proceeds from disposal of property, plant and equipment	173	196	685
Net cash flows used in investing activities	(909,265)	(314,792)	(122,046)
Cash flows from financing activities:			
Proceeds from long-term debt	1,176,733	499,100	173,024
Payments of long-term debt	(548,801)	(473,600)	(529,524)
Payments for debt issuance costs, deferred financing costs and registration costs	(21,204)	(516)	(6,826)
Proceeds from private placement of senior notes	—	—	271,700
Proceeds from private placements, net	—	224,951	5,000
Proceeds from public offering, net	171,395	—	123,256
Exercise of stock options	375	119	311
Cash paid for taxes related to net settlement of share-based payment awards	(61)	—	—
APIC pool for excess tax benefits under SFAS 123R	717	335	177
Payment of dividends and distributions	(111,607)	(16,067)	(9,665)
Distributions to MarkWest Energy unitholders prior to the Merger	(19,651)	(63,916)	(43,500)
Net cash flows provided by (used in) financing activities	647,896	170,406	(16,047)
Net (decrease) increase in cash	(34,374)	(11,149)	27,876
Cash and cash equivalents at beginning of year	37,695	48,844	20,968
Cash and cash equivalents at end of year	$ 3,321	$ 37,695	$ 48,844

	Year ended December 31,		
	2008	2007	2006
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 55,428	$39,714	$32,241
Cash paid for income taxes	19,243	24,317	2,600
Supplemental schedule of non-cash investing and financing activities:			
Accrued property, plant and equipment	$ 51,060	$17,302	$10,922
Interest capitalized on construction in progress	9,486	3,344	891
Property, plant and equipment asset retirement obligation	9	253	64
Merger step-up of fair value	605,100	—	—
Issuance of common units for vesting of share-based payment awards	2,492	1,687	796

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

1. Organization

MarkWest Energy Partners, L.P. (“MarkWest Energy Partners”) was formed on January 25, 2002, as a Delaware limited partnership. MarkWest Energy Partners and its majority-owned subsidiaries (collectively, the “Partnership”) are engaged in the gathering, transportation and processing of natural gas; the transportation, fractionation, marketing and storage of NGLs and the gathering and transportation of crude oil. The Partnership has established a significant presence in the Southwest through strategic acquisitions and strong organic growth opportunities stemming from those acquisitions. The Partnership is also the largest processor of natural gas in the Appalachian Basin, one of the country’s oldest natural gas producing regions. Finally, the Partnership gathers and processes natural gas and owns a crude oil transportation pipeline in Michigan. The Partnership’s principal executive office is located in Denver, Colorado.

On February 21, 2008, MarkWest Energy Partners consummated the transactions contemplated by its plan of redemption and merger (the “Merger”) with MarkWest Hydrocarbon, Inc. (the “Corporation” 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 3. The Merger was accounted for in accordance with Statement of Financial Accounting Standard (“SFAS”) No. 141, *Business Combinations* (“SFAS 141”) and related interpretations. The Merger was considered a downstream merger, whereby the Corporation was viewed as the surviving consolidated entity for accounting and financial purposes rather than the Partnership, which is the surviving consolidated entity for legal purposes. As such, the Merger was accounted for in the Corporation’s consolidated financial statements as an acquisition of non-controlling interest using the purchase method of accounting. As a result, the historical and comparative consolidated financial statements of the surviving legal entity are those of the Corporation, the accounting acquirer, rather than those of the Partnership, the legal acquirer.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Partnership, and have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”).

Non-Controlling Interest in Consolidated Subsidiaries

The Partnership’s consolidated financial statements include the accounts of all majority-owned or majority-controlled subsidiaries. On July 31, 2008, the Partnership acquired a controlling operating interest in Wirth Gathering, a general partnership, as part of the acquisition of PQ Gathering Assets, L.L.C. The 50% interest not acquired by the Partnership is recorded as *Non-controlling interest in consolidated subsidiaries* in the accompanying Consolidated Balance Sheets. The amount recorded in 2008 relates primarily to the Partnership’s 50% controlling operating interest in Wirth Gathering, and the amounts recorded in 2007 and 2006 relate to the non-controlling interest in the Partnership that no longer exists in 2008 due to the Merger (see Note 3).

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

2. Summary of Significant Accounting Policies (Continued)

contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates affect, among other items, valuing identified intangible assets; determining the fair value of derivative instruments; valuing inventory, evaluating impairments of long-lived assets, goodwill and equity investments; establishing estimated useful lives for long-lived assets; recognition of share-based compensation expense; estimating revenues 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.

Marketable Securities

As of December 31, 2007, the Partnership held certain investments classified as *Trading securities* in the accompanying Consolidated Balance Sheets. During 2008, the market mechanism normally used to liquidate the trading securities was no longer operating efficiently. It is not known if the Partnership will be able to sell these investments within the next year. Therefore as of December 31, 2008, the $0.5 million balance associated with these securities has been reclassified to *Other long-term assets* in the accompanying Consolidated Balance Sheets.

Realized and unrealized gains and losses on trading securities are included in earnings. Dividend and interest income are recognized when earned.

Marketable securities classified as available-for-sale are stated at market value, based on the closing price of the securities at the balance sheet date. Accordingly, unrealized gains and losses are reflected in other comprehensive income, net of applicable income taxes. For losses that are other than temporary, the cost basis of the securities is written down to fair value, and the amount of the write down is included in earnings. The Partnership utilizes a first-in first-out cost basis to compute realized gains and losses. Realized gains and losses, dividends, interest income, and the amortization of discounts and premiums are included in earnings. Purchases and sales of securities are recognized on a trade-date basis.

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. During the fourth quarter of 2008, the Partnership recorded a $6.7 million expense to write down inventories to market value. This expense is included in *Purchased product costs* in the accompanying Consolidated Statements of Operations.

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

2. Summary of Significant Accounting Policies (Continued)

assets are expensed as incurred. Interest costs for the construction or development of long-lived assets are capitalized and amortized over the related asset's estimated useful life. Leasehold improvements are depreciated over the shorter of the useful life or lease term. Depreciation is provided, principally on the straight-line method, over 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

In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"), 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 accounts for conditional asset retirement obligations in accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"). FIN 47 clarified the accounting for conditional asset retirement obligations under 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.

Investment in Unconsolidated Affiliates

Equity investments in which the Partnership exercises significant influence, but does not control and is not the primary beneficiary, are accounted for using the equity method, and are reported in *Investment in unconsolidated affiliates* in the accompanying Consolidated Balance Sheets. Refer to Note 12 for further discussion of the Partnership's equity investments.

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

2. Summary of Significant Accounting Policies (Continued)

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 an other-than-temporary loss in value may be identified by:

- The potential inability to recover the carrying amount of the investment;
- The estimated fair value of an investment that is less than its carrying amount. Factors considered include the length of time in which the market has been less than cost and the intent and ability to retain the investment to sufficiently allow for any recovery; and
- Other operational or external factors including economic trends and projected financial performance 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.

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership evaluates goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, the excess of the carrying value over the fair value is recognized as an impairment loss.

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 indicate that the remaining balance may not be recoverable. The Partnership evaluates the carrying value of its property, plant and equipment on at least a segment level and at lower levels where the cash flows for specific assets can be identified and are largely independent from other asset groups. A long-lived asset group is considered impaired when

2. Summary of Significant Accounting Policies (Continued)

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 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 Contract Costs

A wholly-owned subsidiary of the Partnership entered into a series of agreements with a gas producer in September 2004, under which the Partnership processes natural gas under modified keep-whole arrangements. In connection with these agreements, the subsidiary paid $3.3 million of consideration to the producer in connection with these non-separable contracts, which are being amortized as additional cost of the gas purchased over the term of the contracts, October 1, 2004 through February 9, 2015. Amortization related to these contracts for the years ended December 31, 2008, 2007 and 2006 was $0.3 million for each year.

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 Consolidated 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 Partnership discloses the fair value of its commodity derivative instruments separate from other assets and liabilities under the caption *Fair value*

2. Summary of Significant Accounting Policies (Continued)

of derivative instruments in Consolidated Balance Sheet. 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 generally established at its inception.

During 2008, 2007 and 2006, the Partnership 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 designation as a normal purchase or sales contract. Such contracts are normally exempted from the fair value accounting requirements of SFAS 133 and are accounted for using accrual accounting. During 2008, the Partnership did not designate any forward physical contracts as normal purchase or sales contracts. During 2007 and 2006, the Partnership did designate forward physical contracts as normal purchase or sales contracts.

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*, *Purchased product costs* or *Facility expenses*, the same account as the item economically hedged. Revenue gains and losses relate to contracts utilized to hedge the cash flow for the sale of a product. Purchased product costs gains and losses relate to contracts utilized to hedge costs, typically in a keep-whole arrangement. Facility expenses gains and losses relate to a contract utilized to hedge electricity costs. Changes in risk management activities are reported in cash flow from operating activities on the accompanying Consolidated Statements 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 that it is not practical to estimate the fair value of the amounts outstanding under the Partnership's Credit Agreement because the timing of when the outstanding balance will be repaid is highly uncertain. The estimated fair value of the Senior Notes was approximately $627.1 million and $490.7 million at December 31, 2008 and 2007, respectively, based on quoted market prices (see Note 15). Derivative instruments are recorded at fair value, based on available market information (see Note 18).

Fair Value Measurement

The Partnership adopted SFAS No. 157, *Fair Value Measurements* ("SFAS 157"), effective January 1, 2008, with portions deferred by the FASB as discussed in Note 5. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a three-level valuation hierarchy, and expands the disclosures about fair value measurements.

SFAS 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

- Level 1—inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

2. Summary of Significant Accounting Policies (Continued)

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

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

The Partnership's accounting policy requires it to determine the categorization of assets or liabilities based upon the lowest level of input that is significant to the fair value measurement. The Partnership's derivative positions are valued using corroborated market data and internally developed models when observable market data is not available. Crude oil and natural gas swaps are considered Level 2 transactions as the pricing methodology include quoted prices for similar assets and liabilities and the Partnership can determine the prices are observable and do not contain Level 3 inputs that are significant to the measurement. All NGL transactions and crude oil and natural gas options have significant unobservable market parameters and are normally traded less actively or have trade activity that is one way and therefore, are classified within Level 3 of the valuation hierarchy.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Partnership believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. For further discussion on SFAS 157 see Note 5.

Pursuant to the FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157*, the effective date of SFAS 157 for certain non-financial assets and liabilities that are measured at fair value but are recognized or disclosed at fair value on a non-recurring basis has been deferred for one year. The Partnership is primarily impacted by this deferral as it relates to non-financial assets and liabilities initially measured at fair value in a business combination (but not measured at fair value in subsequent periods), long-lived assets measured as fair value for impairment assessment under SFAS 144 and reporting units measured at fair value in the first and second steps of a goodwill impairment test under SFAS 142. The Partnership will adopt these remaining provisions of SFAS 157 effective January 1, 2009. The Partnership does not expect the impact to be significant on the financial position, results of operations and cash flows.

Revenue Recognition

The Partnership generates the majority of its revenues from natural gas gathering, transportation and processing; NGL transportation, fractionation, marketing 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:

- *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.

2. Summary of Significant Accounting Policies (Continued)

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. 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 or less efficiently than specified per contract allowance, the Partnership is entitled to retain the benefit or loss for its own account.

In many cases, the Partnership provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of the Partnership's contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements. 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.

2. Summary of Significant Accounting Policies (Continued)

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 title. 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 $0.2 million and $0.9 million at December 31, 2008 and 2007, recorded in *Accrued liabilities* in the accompanying Consolidated Balance Sheets. The Partnership had an imbalance receivable of $0.9 million and $1.7 million at December 31, 2008 and 2007, respectively, recorded in *Receivables, net* in the accompanying Consolidated Balance Sheets. Changes in gas imbalances are recognized in *Revenue* or *Purchased product costs* in the accompanying Consolidated Statements of Operations.

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. The Partnership issues phantom units under certain share-based compensation plans as describe further in Note 17. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit. The phantom units are treated

2. Summary of Significant Accounting Policies (Continued)

as equity awards under SFAS 123R. 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 corresponding with the vesting period. For certain plans the awards are accounted for as liability awards and the compensation expense is adjusted monthly for the change in the fair value of the unvested units granted.

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

Participation Plan

The interests in the Partnership's General Partner sold by the Corporation to certain directors and employees were referred to as the Participation Plan. The Participation Plan was considered a compensatory arrangement and under SFAS 123R, the General Partner interests were classified as liability awards. As a result, the Corporation was required to calculate the fair value of the General Partner interests at the end of each period. In conjunction with the Merger, all of the outstanding interests in the General Partner were acquired and the Participation Plan was terminated. Refer to Note 17 for further discussion of the impact of the Participation Plan on the financial statements.

Income Taxes

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

The Partnership and the Corporation account for 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 applied to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized 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 net realizable value. Deferred tax balances that are expected to be settled within twelve months are classified as current, and all other deferred tax balance are classified as long term in the accompanying Consolidated Balance Sheets.

The Corporation recognizes a tax expense or a tax benefit on its proportionate share of Partnership income or loss resulting from the Corporation's ownership of Class A units of the Partnership even though for financial reporting purposes said income or loss is eliminated in consolidation. The deferred income tax component relates to the change in the book to tax basis difference in the carrying amount of the investment in the Partnership which results primarily from its

2. Summary of Significant Accounting Policies (Continued)

timing differences in the Corporation's proportionate share of the book income or loss as compared with the Corporation's proportionate share of the taxable income or loss of the Partnership.

The Partnership 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. Under the provisions of FIN 48, the Partnership records interest and penalties related to income taxes as a component of income before tax. Penalties are recorded in *Miscellaneous (expense) income* and interest is recorded in *Interest expense* in the accompanying Consolidated Statements of Operations. 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 marketable securities that are classified as available for sale in accordance SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities.*

Earnings (Loss) Per Unit

Basic and diluted net income (loss) per common unit is calculated in accordance with SFAS No. 128, *Earnings per Share* ("SFAS 128"). Basic net income (loss) per common unit is calculated by dividing net income (loss) by the weighted-average number of common units outstanding during the period. Diluted net income per unit is calculated by dividing net income by the weighted-average number of common units outstanding during the period, including potential common units from the vesting of phantom units. Potential common units are excluded from the calculation during periods in which the Partnership incurs a net loss as the impact would be anti-dilutive.

Business Combinations

The Partnership accounts for business combinations in accordance with SFAS 141. The net assets acquired are recorded at the estimated fair market values as of the acquisition date. The purchase price in excess of the fair value acquired is recorded as goodwill.

Accounting for Sales of Stock by a Subsidiary

Prior to the Merger, the Partnership issued common units in various transactions, which resulted in a dilution of the Corporation's percentage ownership in the Partnership. The Corporation accounted for the sale of the Partnership common units in accordance with the Securities and Exchange Commission Staff Accounting Bulletin No. 51, *Accounting for Sales of Stock by a Subsidiary* ("SAB 51"). SAB 51 allows for the election of an accounting policy of recording such increase or decreases in a parent's investment (SAB 51 gains or losses, respectively) either in income or in equity. The Corporation adopted a policy of recording such SAB 51 gains or losses directly to additional paid in capital. Due to the preference nature of the Partnership's common units, the Corporation was

2. Summary of Significant Accounting Policies (Continued)

precluded from recording SAB 51 gains or losses until the subordinated units converted to common units. On August 15, 2007, the Partnership converted its remaining 1.2 million subordinated units to common units, in accordance with the provisions of the amended and restated partnership agreement. As a result, the Corporation recorded a $52.3 million SAB 51 gain to additional paid in capital, a decrease in non-controlling interest in consolidated subsidiary of $83.8 million and an increase to deferred tax liability of $31.5 million associated with gains from sales of common units by the Partnership in conjunction with, and subsequent to, the Partnership's May 24, 2002 initial public offering.

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 at 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.*

The adoption of SFAS 157 as of January 1, 2008 had an effect of a $1.1 million decrease to fair value of derivative instruments liability, a decrease to Revenue—derivative loss of $0.4 million and an increase to derivative gain related to purchase product costs of $0.7 million. The provisions of SFAS 157 adopted as of January 1, 2009 will not have a material 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

2. Summary of Significant Accounting Policies (Continued)

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 adoption of SFAS 159 did not impact the Partnership's Consolidated Financial Statements since the Partnership did not elect the fair value option.

In October 2008 the FASB issued Staff Position ("FSP") No. FSP 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active* ("FSP 157-3"). FSP 157-3 clarifies the application of SFAS 157 as it relates to the valuation of financial assets in a market that is not active for those financial assets. FSP 157-3 is effective immediately and includes those periods for which financial statements have not been issued. The adoption of FSP 157-3 did not have a material impact on the Partnership's consolidated financial statements.

In December 2007 the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). This statement replaces SFAS No. 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 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 adoption of SFAS 141R is not expected to have a material impact on the Partnership's consolidated financial statements.

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 non-controlling 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 adoption of SFAS 160 is not expected to have a material impact on the Partnership's consolidated financial statements.

In March 2008 the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* ("SFAS 161"). SFAS 161 amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and requires entities to provide enhanced qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair values and amounts of gains and losses on derivative contracts, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS 161 will be effective for the Partnership as of January 1, 2009. The principal impact to the Partnership will be to require expanded disclosure regarding derivative instruments.

2. Summary of Significant Accounting Policies (Continued)

In April 2008 the FASB issued FSP 142-3, *Determination of the Useful Life of Intangible Assets* ("FSP 142-3"). FSP 142-3 amends the factors that an entity should consider in developing renewal or extension assumptions used in determining the useful life of recognized intangible assets under SFAS 142. In determining the useful life of an acquired intangible asset, FSP 142-3 removes the requirement from SFAS 142 for an entity to consider whether renewal of the intangible asset requires significant costs or material modifications to the related arrangement. FSP 142-3 also replaces the previous useful life assessment criteria with a requirement that an entity consider its own experience in renewing similar arrangements. If the entity has no relevant experience, it would consider market participant assumptions regarding renewal. FSP 142-3 will be effective as of January 1, 2009 and will apply only to intangible assets acquired after that date. Retroactive application to previously acquired intangible assets is prohibited. The adoption of FSP 142-3 is not expected to have a material impact on the Partnership's consolidated financial statements.

In May 2008 the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* ("SFAS 162"). SFAS 162 provides a consistent framework for determining what accounting principles should be used when preparing US GAAP financial statements and is effective for all nongovernmental entities on November 15, 2008. The adoption of SFAS 162 did not have a material impact on the Partnership's consolidated financial statements.

In June 2008 the FASB issued FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1"). FSP EITF 03-6-1 states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per unit pursuant to the two-class method as described in SFAS No. 128, *Earnings per Share*. FSP EITF 03-6-1 is effective for the Partnership beginning January 1, 2009. The adoption of FSP EITF 03-6-1 will not have any impact on the net income reported in the Partnership's Consolidated Statements of Operations, however, the reported earnings per unit will generally be lower than the amount reported prior to adoption. If the provisions of FSP EITF 03-6-1 had been effective for the fiscal year ended December 31, 2008, both of the Partnership's basic and diluted earnings per unit would have been $4.02, compared to the reported per unit amounts of $4.08 and $4.04, respectively.

In November 2008 the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 08-6, *Equity Method Investment Accounting Considerations* (EITF No. 08-6). The consensus opinion in EITF No. 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments which were affected by the FASB issuances of SFAS 141R and SFAS 160. The transition provisions require prospective application and are effective for the Partnership on January 1, 2009. EITF No. 08-6 will not have a material effect on the Partnership's consolidated financial statements.

3. Redemption and Merger

On February 21, 2008, the Partnership completed the transactions contemplated by its plan of redemption and merger with the Corporation and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership. Under the Merger, the shareholders of the Corporation exchanged each share of Corporation common stock for consideration equal to 1.9051 Partnership common units. This Exchange Ratio was computed based on the stated consideration of 1.285 Partnership common units plus $20 in cash, or equivalent value. In accordance with the merger agreement, the equivalent value was based on a Partnership common unit price of $32.25, which equals the average market price of Partnership common units for the ten day period ending three days prior to the closing date. Therefore, the $20.00 in cash was equivalent to 0.6201 Partnership common units which results in a total Exchange Ratio of 1.9051 when combined with the other 1.285 units included in the stated consideration. Subject to proration, the shareholders elected to receive this consideration either entirely in cash in the redemption, entirely in Partnership common units in the Merger, or in any combination of cash and Partnership common units with equivalent value. The Corporation redeemed for $240.5 million in cash those shares of Corporation common stock electing to receive cash. Immediately after the redemption, the Partnership acquired the Corporation through a merger of MWEP, L.L.C. with and into the Corporation, pursuant to which all remaining shares of the Corporation's common stock were converted into approximately 15.5 million Partnership common units. As a result of the Merger, the Corporation 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 held by MarkWest Energy GP, L.L.C. (the "General Partner") and the Partnership common units owned by the Corporation 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 Corporation and the General Partner under the Participation Plan in exchange for approximately $21.5 million in cash and approximately 0.9 million common units valued at $30.1 million. Additionally, as a result of the Merger, the Partnership assumed the 2006 Hydrocarbon Stock Incentive Plan and the 1996 Hydrocarbon Stock Incentive Plan (see Note 17).

Using the Exchange Ratio, the number of Corporation shares outstanding as of December 31, 2007 and activity through February 21, 2008 has been adjusted to the equivalent number of Partnership common units in the accompanying Consolidated Financial Statements. The following table illustrates these conversions (shares and units in thousands):

	Common Shares	Exchange Ratio	Common Units
Shares of Corporation Common Stock Outstanding at December 31, 2007	11,999.8	1.9051	22,861
Stock Option exercises in first quarter 2008, prior to Merger	51.5	1.9051	98
Conversion of Restricted Shares to Partnership Phantom units	(23.8)	1.9051	(45)
Shares eligible for redemption or conversion to Partnership Units	12,027.5		22,914
Common shares tendered for redemption in cash	(3,914.5)	1.9051	(7,458)
Common shares tendered for conversion to Partnership common units	8,113.0	1.9051	15,456

Class A units represent limited partner interests in the Partnership and have identical rights and obligations of the Partnership common units except that Class A units (a) do not have the right to vote

3. Redemption and Merger (Continued)

on, approve or disapprove, or otherwise consent to or not consent to any matter (including mergers, share exchanges and similar statutory authorizations) except as otherwise required by any non-waivable provision of law and (b) do not share in any cash and cash equivalents on hand, income, gains, losses, deductions and credits that are derived from or attributable to the Partnership's ownership of, or sale or disposition of, the shares of MarkWest Hydrocarbon common stock. Pursuant to Accounting Research Bulletin No. 51, *Consolidated Financial Statements*, the Class A units held by the Corporation and the General Partner are not treated as outstanding common units in the Consolidated Balance Sheets.

The total fair value of the non-controlling interest 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 of $31.79. The following table shows the calculation of the purchase price of the Partnership ($ in thousands):

	Units	Dollars
Fair value of units held prior to Merger	34,473,647	$1,095,917
Add: Direct costs of the Merger		7,882
		$1,103,799

Significant fair value estimates were required for the following assets and liabilities:

- Property, plant, and equipment—The fair value estimates for property, plant and equipment were based primarily on the cost approach, which considers both historical cost and replacement cost. Additionally, management estimated the remaining useful lives of the property, plant and equipment to ensure that the useful lives used for depreciation subsequent to the Merger are reasonable and consistent with the Partnership's accounting policy.
- Intangible assets—The fair value estimates for customer relationships were based on a version of the income approach. The income approach involves estimating future cash flows from existing customer relationships and making provisions for a fair return on other recognized contributory assets. Key assumptions in the valuation include contract renewals, economic incentives to retain customers, historic volumes, current and future capacity in the gathering system, pricing volatility and the discount rate. The estimated useful life of the intangible assets was determined by assessing the estimated useful life of the other assets to which the contracts and relationships relate, likelihood of renewals, projected reserves, competitive factors, regulatory or legal provisions, and maintenance and renewal costs.
- Long-term debt—The fair value of the Partnership's Senior Notes was estimated using a high yield market price at which the debt was trading as of the date the Merger closed.
- Deferred finance costs—The deferred finance costs of the Partnership had no fair market value as of the date the Merger closed. Therefore 85.7% of these costs, which is the percentage subject to revaluation under the purchase accounting method, have been written-off.
- The remaining purchase price in excess of the fair values of the assets and liabilities acquired was recorded as goodwill. The goodwill balance was then allocated to the Partnership's reporting units. SFAS 142 defines a reporting unit as an operating segment or a component of an operating segment. Based on the criteria set forth in SFAS 142, the Partnership has eight

3. Redemption and Merger (Continued)

reporting units: East Texas, Eastern Oklahoma, Western Oklahoma, Other Southwest, Javelina, Appalachia, Western Michigan, and Michigan Crude Pipeline. Goodwill was allocated to those reporting units that are expected to benefit from the business combination. One of the primary benefits of the Merger was to allow the Partnership to compete more effectively for future growth opportunities. Because there were no significant growth plans in place for Western Michigan and Michigan Crude Pipeline, no goodwill was allocated to these reporting units. For all other reporting units, goodwill was allocated in a manner consistent with the methodology used to determine total goodwill. Management estimated the fair value of the net assets of reporting unit, allocated a portion of the Merger purchase price to each reporting unit, and assigned goodwill to the extent that the allocated purchase price exceeded the fair value of the reporting unit. The methodology used to determine the fair value of the net assets of each reporting unit and the allocated purchase price to each reporting unit was applied consistently.

The following table shows the final purchase price allocation as of February 21, 2008 (in thousands):

	Original Net Book Value	Fair Value	85.7% Proportional Step-Up of Fair Value	Average Depreciable Life
Property, plant and equipment	$ 843,122	$1,051,407	$ 178,501	18
Intangible assets	324,326	780,343	390,807	18
Long-term debt	(581,642)	(570,775)	9,313	8
Deferred financing costs	12,815	—	(10,982)	8
Goodwill			37,461	
Total Adjustments			605,100	
Deferred income taxes	n/a	n/a	(3,598)	
Non-controlling interest			502,297	
Total Purchase Price			$1,103,799	

n/a—Amounts represent the recognition of deferred tax liabilities related to temporary tax differences that are expected to reverse in future periods related to the proportional step-up of fair value due to the Merger. No deferred tax liabilities related to goodwill were recognized as goodwill is not deductible for tax purposes.

4. Business Combinations

The Partnership completed the following business combinations during the years ended December 31, 2008, 2007 and 2006, in addition to the Merger. Each transaction was accounted for under the purchase method. The net assets acquired 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 business combinations are included in the consolidated financial statements from the acquisition date.

4. Business Combinations (Continued)

PQ Gathering Assets, L.L.C.

On July 31, 2008, the Partnership acquired a 100% interest in PQ Gathering Assets, L.L.C. ("PQ Assets") from PetroQuest Energy, L.L.C. for $41.3 million. PQ Assets consisted of gathering systems located in the Woodford Shale area of Southeast Oklahoma. The acquisition also included a 50% managing partner operating interest in Wirth Gathering, a general partnership, which also owns a gathering system located in the Woodford Shale area. PQ Assets was renamed MarkWest McAlester, L.L.C. The Partnership obtained a third-party valuation of the net assets acquired which is reflected in the table below.

Santa Fe Gathering, L.L.C.

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 assets acquired consist of a gathering system located in Roger Mills and Beckham Counties, Oklahoma. The gathering system was constructed in May 2005 to gather from growing production fields. Santa Fe Gathering was merged with MarkWest Oklahoma, L.L.C.

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

	2008	2006
	PQ Gathering Assets, L.L.C.	Santa Fe Gathering, L.L.C.
Acquisition costs:		
Cash consideration	$41,300	$14,941
Direct acquisition costs	—	29
Total	$41,300	$14,970
Allocation of acquisition costs:		
Current assets	$ —	$ 331
Inventory	—	11
Property, plant and equipment	26,698	3,087
Customer contracts and relationships(1)	16,872	11,959
Goodwill(2)	665	—
Non-controlling interest	(2,935)	—
Liabilities assumed	—	(418)
Total	$41,300	$14,970

(1) Customer contracts and relationships will be amortized over the remaining ten-year life.

(2) Goodwill was recorded in the Southwest segment.

5. Fair Value

Fair Value Measurement

The Partnership adopted SFAS 157 on January 1, 2008. 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 applies to all fair value measurements however the FASB deferred the effective date for certain nonfinancial assets and liabilities until January 1, 2009 (see Note 2). SFAS 157 applies principally to the Partnership's derivative positions and trading securities at December 31, 2008.

Valuation Hierarchy

Following is a description of the valuation methodologies the Partnership used for instruments measured at fair value, as well as the general classification of such instruments pursuant to the valuation hierarchy. For discussion of the three levels in the valuation hierarchy, see Note 2.

Commodity Derivative Transactions

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. The Partnership's derivative positions are valued using corroborated market data and internally developed models when observable market data is not available. Crude oil and natural gas swaps are considered Level 2 transactions as the pricing methodology include quoted prices for similar assets and liabilities and the Partnership can determine the prices are observable and do not contain Level 3 inputs that are significant to the measurement. All NGL transactions and crude oil and natural gas options have significant unobservable market parameters and are normally traded less actively and therefore are classified within Level 3 of the valuation hierarchy. Due to limited liquidity and trading activity, models interpolate pricing curves within a range where broker quotes are not available, remove outlying quotes and adjust for seasonality.

Trading Securities

Trading securities consist exclusively of auction rate securities as of December 31, 2008 and are included in *Other long-term assets* in the accompanying Consolidated Balance Sheets. Quoted market prices are not available and these securities' fair values are estimated by using pricing models, quoted prices of securities with similar characteristics, or discounted cash flows. Considering observable market activity is not available for these securities, the securities are classified within Level 3 of the valuation hierarchy.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Partnership believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at December 31, 2008.

5. Fair Value (Continued)

The following table presents the financial instruments carried at fair value as of December 31, 2008, and by SFAS 157 valuation hierarchy (as described above, in thousands):

	Assets		Liabilities
	Trading Securities	Derivatives	Derivatives
Quoted prices in active markets for identical assets (Level 1)	$ —	$ —	$ —
Significant other observable inputs (Level 2)	—	106,826	(49,378)
Significant unobservable inputs (Level 3)	512	75,512	(3,056)
Total carrying value in Consolidated Balance Sheet	$512	$182,338	$(52,434)

Changes in Level 3 fair value measurements

The tables below include a rollforward of the balance sheet amounts for the year ended December 31, 2008 (including the change in fair value) for financial instruments classified by the Partnership within Level 3 of the valuation hierarchy (in thousands). When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. However, Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources); accordingly, the gains and losses in the table below include changes in fair value due in part to observable factors that are part of the valuation methodology. Level 3 includes options for natural gas and all crude oil positions as they have significant unobservable market parameters and are normally traded less actively and therefore are classified within Level 3 of the valuation hierarchy. For the periods ended March 31, June 30 and September 30, 2008 the Partnership considered options to be Level 2. After further consideration, options are considered Level 3 due to significant unobservable inputs.

	Trading Securities	Derivatives (net)
Fair value January 1, 2008	$ 3,674	$ (84,367)
Total gain or loss (realized and unrealized) included in earnings(a)(b)	(762)	108,653
Purchases, sales, issuances and settlements (net)	(2,400)	48,170
Transfers in or out of Level 3 (net)	—	—
Fair value December 31, 2008	$ 512	$ 72,456
The amount of total gains or losses for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at December 31, 2008(a)	$ —	$115,875

(a) Gains and losses on derivative positions classified as Level 3 are recorded in *Derivative gain (loss)*, a component of *Total revenue*.

(b) Gains and losses on trading securities are realized and recorded in *Miscellaneous (expense) income*.

5. Fair Value (Continued)

Assets and liabilities measured at fair value on a nonrecurring basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the instruments are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. As of December 31, 2008, there were not any assets or liabilities to be measured at fair value on a nonrecurring basis.

6. Marketable Securities

As of December 31, 2007, the Partnership held certain investments classified as *Trading securities* in the accompanying Consolidated Balance Sheets. During the year ended December 31, 2008, the market mechanism normally used to liquidate the trading securities was no longer operating efficiently. It is not known if the market mechanism will become efficient within the next year. Therefore as of December 31, 2008, the $0.5 million balance associated with these securities has been reclassified to *Other long-term assets* in the accompanying Consolidated Balance Sheets.

The following are the components of marketable securities (in thousands):

	Cost Basis	Other-than-temporary Impairment	Fair Value
December 31, 2008			
Trading securities	$1,198	$(686)	$512

	Cost Basis	Net Unrealized Gains (Losses)	Fair Value
December 31, 2007			
Trading securities	$3,698	$ (24)	$ 3,674
Available for sale securities	4,988	1,486	6,474
	$8,686	$1,462	$10,148

For the years ended December 31, 2008 and 2007, the Partnership recognized a net unrealized loss on marketable securities of zero and $0.2 million, respectively, net of the related tax benefit of zero and $0.1 million, respectively. The loss in 2007 is shown as a component of other comprehensive income.

The Partnership recognized an other-than-temporary loss of $0.7 million and zero on its trading securities during the years ended December 31, 2008 and 2007, respectively. This loss is included in *Miscellaneous (expense) income* in the accompanying Consolidated Statements of Operations.

7. Significant Customers and Concentration of Credit Risk

For the years ended December 31, 2008, 2007, and 2006, revenues from one customer totaled $234.0 million, $191.5 million and $76.0 million, representing 22.1%, 22.6% and 9.2% of consolidated Partnership revenue excluding derivative gain (loss), respectively. Sales to this customer are made primarily from the Southwest segment. As of December 31, 2008, 2007 and 2006, the Partnership had $6.5 million, $6.4 million and $3.0 million of accounts receivable from this customer, respectively.

7. Significant Customers and Concentration of Credit Risk (Continued)

For the years ended December 31, 2008, 2007 and 2006, revenues from another customer totaled $87.6 million, $88.9 million and $63.0 million, representing 8.3%, 10.5% and 7.6% of consolidated Partnership revenue excluding derivative gain (loss), respectively. Sales to this customer are made primarily from the Southwest segment. As of December 31, 2008, 2007 and 2006, the Partnership had $2.4 million, $9.5 million and $5.2 million of accounts receivable from this customer, respectively.

8. Receivables and Other Current Assets

Receivables consist of the following (in thousands):

	December 31, 2008	December 31, 2007
Trade, net	$ 88,370	$121,099
Other(1)	13,479	9,778
Total receivables	$101,849	$130,877

(1) Relates primarily to amounts due from the settlement of derivative positions.

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

	December 31, 2008	December 31, 2007
Margin deposits	$ —	$40,260
Prepaid fuel	1,114	1,605
Income tax receivable	8,416	3,212
Prepaid Merger costs	—	4,771
Prepaid insurance	810	333
Prepaid other	1,408	997
Total other current assets	$11,748	$51,178

9. Property, Plant and Equipment

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

	December 31, 2008	December 31, 2007
Natural gas gathering facilities, natural gas pipelines and other	$1,067,328	$ 657,878
Gas processing plants	225,794	213,414
Fractionation and storage facilities	24,498	24,388
Crude oil pipelines	16,104	21,588
NGL transportation facilities	10,888	4,676
Furniture, office equipment and other	1,304	2,672
Construction in progress	304,776	51,553
Property, plant and equipment	1,650,692	976,169
Less: accumulated depreciation	(81,167)	(145,360)
Total property, plant and equipment, net	$1,569,525	$ 830,809

The Partnership capitalizes interest on major projects during construction. For the years ended December 31, 2008, 2007 and 2006, the Partnership capitalized interest, including deferred finance costs, of $9.5 million, $3.3 million and $0.9 million, respectively.

10. Goodwill and Intangible Assets

Goodwill. The purchase price in excess of the fair value of the minority interest in the net assets and liabilities of the Partnership at the time of the Merger between MarkWest Energy Partners and MarkWest Hydrocarbon was recorded as goodwill in the amount of $37.5 million. Goodwill of $23.7 million, $3.9 million and $9.9 million was allocated to individual reporting units within the Southwest, Northeast and Gulf Coast segments, respectively. In addition, the purchase price in excess of the fair value of the net assets acquired in the purchase of PQ Assets was also recorded as goodwill in the amount of $0.7 million which was allocated to the Southwest segment. In accordance with SFAS 142, goodwill is not amortized but instead tested for impairment annually, or more frequently when events and circumstances occur indicating that the recorded goodwill may not be recoverable. As of December 31, 2008, goodwill was $9.4 million (see Note 11). The Partnership did not have goodwill recorded prior to 2008.

Intangible Assets. The Partnership's intangible assets as of December 31, 2008 and 2007 are comprised of customer contracts and relationships, as follows (in thousands):

	December 31, 2008			December 31, 2007			
Description	**Gross**	**Accumulated Amortization**	**Net**	**Gross**	**Accumulated Amortization**	**Net**	**Useful Life**
Southwest	$407,544	$(24,708)	$382,836	$177,338	$(28,850)	$148,488	20 yrs
Northeast	68,573	(5,876)	62,697	—	—	—	10 yrs
Gulf Coast	262,772	(12,388)	250,384	195,137	(16,903)	178,234	25 yrs
Total:	$738,889	$(42,972)	$695,917	$372,475	$(45,753)	$326,722	

Amortization expense related to the intangible assets was $38.5 million, $16.7 million and $16.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Estimated future amortization expense related to the intangible assets at December 31, 2008, is as follows (in thousands):

Year ending December 31,	
2009	$ 40,795
2010	40,795
2011	40,795
2012	40,795
2013	40,795
Thereafter	491,942
	$695,917

11. Impairment of Goodwill and Long-Lived Assets

Goodwill. The Partnership's policy is to evaluate goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Due to the decline in the market prices of crude oil and other NGLs in December 2008, management significantly reduced the short- and medium-term forecasts for the net income and cash flow to be generated by the Partnership's reporting units. Management considered this significant change in the forecast and the continued decline in the trading price for its common units to be an indication of potential impairment, and therefore completed the goodwill impairment test as of November 30 and December 31, 2008. As a

11. Impairment of Goodwill and Long-Lived Assets (Continued)

result of these analyses, the Partnership recorded impairment charges of $28.7 million to write-off the goodwill balance allocable to four of the Partnership's reporting units. Approximately $18.8 million and $9.9 million of the goodwill impairment related to the Southwest and Gulf Coast segments, respectively. The remaining goodwill balance of $9.4 million consists of the $5.5 million allocated to the East Texas reporting unit in the Southwest segment and the $3.9 million allocated to the Appalachia reporting unit in the Northeast segment. In completing the evaluation, management estimated the fair value of the Partnership's reporting units primarily using an income approach based on discounted future cash flows. Management also considered a market approach based on the Partnership's market capitalization as of December 31, 2008. Because management believes the market capitalization of the Partnership has been adversely impacted by global economic factors and does not accurately represent the full underlying value of the Partnership's assets, the income approach was weighted more heavily in the analysis.

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, plant and equipment and intangibles on at least a segment level and at lower levels where cash flows for specific assets can be identified.

An analysis completed in 2008 indicated an impairment of the Partnership's gas-gathering assets in Manistee County, Michigan, which are part of the Partnership's Northeast segment, due to the decision to move the Fisk plant to Pennsylvania and to outsource the gas processing to a third party. The Partnership used the market approach to determine the assets' fair value and recognized an impairment of long-lived assets of $7.6 million for the year ended December 31, 2008.

An analysis completed in 2007 determined that a system located in the Partnership's 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 for the year ended December 31, 2007.

12. Investment in Unconsolidated Affiliates

The Partnership applies the equity method of accounting for its 50% non-operating interest in Starfish Pipeline Company, L.L.C. ("Starfish") and its 40% non-operating interest in Centrahoma Processing, L.L.C. ("Centrahoma"). Differences between the Partnership's investment and its proportionate share of reported equity are amortized based upon the respective useful lives of the assets to which the differences relate.

The table below shows the carrying value of the Partnership's equity investments (in thousands):

	December 31,	
	2008	2007
Investment in Starfish	$17,181	$58,709
Investment in Centrahoma	28,911	—
Total investment in unconsolidated affiliates	$46,092	$58,709

12. Investment in Unconsolidated Affiliates (Continued)

On March 1, 2008, the Partnership acquired a 20% interest in Centrahoma for $11.6 million. On May 9, 2008, the Partnership exercised its option to acquire an additional 20% interest in Centrahoma for $12.0 million including a capital call. Centrahoma owns certain processing plants in the Arkoma Basin. In addition, the Partnership signed agreements to dedicate our processing rights in certain acreage in the Woodford Shale area to Centrahoma through March 1, 2018. The Partnership's share of Centrahoma's loss was $0.3 million for the year ended December 31, 2008. The following table includes summarized balance sheet data as of December 31, 2008 for 100% of Centrahoma (in thousands):

Current assets	$ 9,192
Noncurrent assets	71,804
Current liabilities	8,728
Noncurrent liabilities	—

The following table includes summarized results of operations from inception on February 11, 2008 to December 31, 2008 for 100% of Centrahoma (in thousands):

Revenue	$79,643
Operating loss	(718)
Net loss	(718)

In September 2008, Hurricane Ike caused wind and water damage to oil and gas assets in the Gulf of Mexico and Gulf Coast regions, including damage to several onshore and offshore facilities of Starfish. Due to the damage in the region, the operations of Starfish have been partially curtailed since the middle of September resulting in a decrease in the Partnership's *Earnings from unconsolidated affiliates* in the accompanying Consolidated Statements of Operations. The Partnership has contributed $5.0 million of additional capital to fund the repairs resulting from the hurricane and may receive additional capital calls in 2009. The Partnership's share of Starfish's net income was $0.4 million, $5.3 million and $5.3 million for the years ended December 31, 2008, 2007 and 2006, respectively. The Partnership expects to file insurance claims to recover a portion of the losses associated with the business interruption and the costs associated with damage repairs.

During the fourth quarter of 2008, management determined that a combination of factors indicated that the fair value of the investment in Starfish may have declined below the carrying value. These factors include the increase in the investment balance due to the capital call associated with the damage repairs and a forecasted reduction in the expected future cash distributions from Starfish. The current commodity price environment, damage to oil and gas assets in the region, and uncertainty of whether or not volumes will return to pre-hurricane levels, have led to a downward revision of Starfish's short- and long-term financial forecast. As a result of these indicators, management completed an impairment evaluation as of December 31, 2008. Prior to completing the impairment evaluation, the recorded value of the investment in Starfish was $58.6 million. Using an income approach based on estimated discounted cash flows, management estimated that the fair value of the Partnership's investment in Starfish was approximately $17.2 million. Management believes that the downward revisions to the Starfish forecast are likely to be permanent. Therefore, the decline in value is considered to be other-than-temporary and an impairment charge of $41.4 million has been recorded in the accompanying Consolidated Statements of Operations.

13. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	December 31, 2008	December 31, 2007
Accrued property, plant and equipment	$ 51,060	$17,302
Interest	22,591	13,456
Product and operations	20,610	23,608
Taxes (other than income tax)	6,578	4,213
Bonus and profit sharing, severance and vacation accruals	4,074	4,915
Deferred lease obligation	2,620	2,235
Professional services	1,688	1,166
Deferred income	1,044	1,539
Phantom unit accrual	735	2,807
Other	34	986
Accrued derivative settlements	—	7,642
Total accrued liabilities	$111,034	$79,869

14. Asset Retirement Obligation

The Partnership's assets subject to asset retirement obligations are primarily certain gas-gathering pipelines and processing facilities, a crude oil pipeline and other related pipeline assets. The Partnership also has land leases that require the Partnership to return the land to its original condition upon termination of the lease. In accordance with SFAS 143, the Partnership reviews current laws and regulations governing obligations for asset retirements and leases, as well as the Partnership's leases and other agreements.

The following is a reconciliation of the changes in the asset retirement obligation from January 1, 2007 to December 31, 2008 (in thousands):

	Year ended December 31, 2008	Year ended December 31, 2007
Beginning asset retirement obligation	$1,635	$1,268
Liabilities incurred	9	109
Revisions in estimated cash flows	—	144
Accretion expense	129	114
Ending asset retirement obligation	$1,773	$1,635

At December 31, 2008, 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.

15. Long-Term Debt

Debt is summarized below (in thousands):

	December 31, 2008	December 31, 2007
Credit Facility		
Revolver facility, 7.09% interest at December 31, 2007, retired February 2008	$ —	$ 55,500
Revolver facility, 2.51% interest at December 31, 2008, due February 2012(1)	184,700	—
Senior Notes		
Senior Notes, 6.875% interest, net of discount of $9,676 and $0, respectively, due November 2014(2)	215,324	225,000
Senior Notes, 8.5% interest, net of discount of $882 and $2,805, respectively, due July 2016(2)	274,118	272,195
Senior Notes, 8.75% interest, net of discount of $1,177 and $0, respectively, due April 2018	498,823	—
Total long-term debt	$1,172,965	$552,695

(1) Borrowings are due in February 2012 as a result of the amendment executed in March 2009.

(2) The reported balances for the Senior Notes due November 2014 and July 2016 were adjusted to fair value as part of the accounting for the Merger (see Note 3).

Credit Facility

On February 20, 2008, the Partnership entered into a new credit agreement ("Partnership Credit Agreement"). The Partnership Credit Agreement originally provided for a maximum lending limit of $575.0 million through February 2013. The Partnership Credit Agreement included a senior secured revolving credit facility of $350.0 million (that under certain circumstances could be increased to $550.0 million) and a $225.0 million term loan, both of which could be repaid at any time without penalty. Initial borrowings under the revolving credit facility portion of Partnership Credit Agreement were used to finance other payments under the Merger and to repay amounts due on the old partnership credit facility revolver of $67.0 million. The Partnership retired the term loan in April 2008 using a portion of the proceeds from a private placement of Senior Notes completed on April 15, 2008. The Partnership recorded a charge of $4.2 million to write-off the deferred financing costs associated with the term loan, which is included in *Amortization of deferred financing costs and discount* in the accompanying Consolidated Statements of Operations. The credit facility is guaranteed and collateralized by substantially all of the Partnership's assets and those of its wholly-owned subsidiaries. As of December 31, 2008, the Partnership had $184.7 million of borrowings outstanding under the revolving credit facility and approximately $107.5 million of available borrowings, with outstanding letters of credit of $57.8 million. The Partnership Credit Agreement was amended in March 2009 (see Note 26).

15. Long-Term Debt (Continued)

The borrowings under the revolving credit facility of the Partnership Credit Agreement 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%, and b) a rate set by the Partnership Credit Agreement'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 50 to 125 basis points for Base Rate loans, and 150 to 225 basis points for LIBOR loans. The basis points will increase by 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 and 50 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 Agreement). As of December 31, 2008, the weighted average interest rate for borrowings under the Partnership Credit Agreement was 2.51%.

Senior Notes

MarkWest Energy Partners, L.P. and its wholly-owned subsidiary MarkWest Energy Finance Corporation (the "Issuers"), have three series of senior notes outstanding as of December 31, 2008: $225.0 million principal due in November 2014 (the "2014 Senior Notes"), $275.0 million principal due in July 2016 (the "2016 Senior Notes") and $500.0 million principal due in 2018 (the "2018 Senior Notes" and all together with the 2014 Senior Notes and 2016 Senior Notes, the "Senior Notes"). The estimated fair value of the Senior Notes was approximately $627.1 million and $490.7 million at December 31, 2008 and December 31, 2007, respectively, based on quoted market prices.

The Issuers have no independent operating assets or operations. All wholly-owned subsidiaries, other than MarkWest Energy Finance Corporation, guarantee the Senior Notes, jointly and severally and fully and unconditionally. The 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 the Partnership Credit Agreement.

The indentures governing the Senior Notes limit the activity of the Partnership and its restricted subsidiaries. Limitations under the indentures 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 indentures pursuant to Rule 144A and Regulation S under the Securities Act of 1933. If at any time the Senior Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Rating Services and

15. Long-Term Debt (Continued)

no default (as defined in the Indentures) has occurred and is continuing, many of such covenants will be suspended during the period of time in which the foregoing requirements are met or will terminate entirely, in which case the Partnership and its subsidiaries will cease to be subject to such terminated covenants.

2014 Senior Notes. In October 2004, the Issuers completed a private placement, subsequently registered, of $225.0 million in senior notes at a fixed rate of 6.875%, payable semi-annually in arrears on May 1 and November 1, commencing May 1, 2005. The 2014 Senior Notes mature on November 1, 2014.

2016 Senior Notes. In July 2006, the Issuers completed a private placement, subsequently registered, of $200 million in aggregate principal amount of 8.5% senior notes due 2016 to qualified institutional buyers. The 2016 Senior Notes will mature on July 15, 2016, and interest is payable semi-annually in arrears on 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.

2018 Senior Notes. In April 2008, the Issuers completed a private placement, subsequently registered, of $400 million in aggregate principal amount of 8.75% senior notes to qualified institutional buyers under Rule 144A. The 2018 Notes mature on April 15, 2018, and interest is payable semi-annually in arrears on April 15 and October 15, commencing October 15, 2008. The Partnership received approximately $388.1 million, after deducting initial purchasers' discounts and the expenses of the offering. Also, on May 1, 2008, the Partnership completed the placement of an additional $100.0 million pursuant to the indenture to the 2018 Senior Notes. The Partnership received approximately $100.4 million, after including initial purchasers' premium and the estimated expenses of the offering. The notes issued in this offering and the notes issued on April 15, 2008, are treated as a single class of debt securities under this same indenture. The Partnership utilized approximately $275.0 million of the net proceeds from the offerings to repay the $225.0 million term loan portion of the Partnership Credit Agreement entered into on February 20, 2008 and to partially fund its 2008 capital expenditure requirements.

The aggregate minimum principal payments on long-term debt are as follows, as of December 31, 2008, exclusive of any prepayments allowable under the Partnership's debt agreements (in thousands):

Year ending December 31:	
2009	$ —
2010	—
2011	—
2012	184,700
2013	—
Thereafter	1,000,000
	$1,184,700

16. Income Tax

The components of the provision for income tax expense (benefit) are as follows (in thousands):

	Year ended December 31,		
	2008	2007	2006
Current income tax expense (benefit):			
Federal	$12,947	$ 22,386	$ (288)
State	2,085	1,483	109
Total current	15,032	23,869	(179)
Deferred income tax expense (benefit):			
Federal	50,129	(45,029)	5,416
State	3,669	(3,489)	15
Total deferred	53,798	(48,518)	5,431
Provision for income tax expense (benefit)	$68,830	$(24,649)	$5,252

A reconciliation of the provision for income tax and the amount computed by applying the federal statutory rate of 35% to the income before income taxes for the year ended December 31, 2008 is as follows (in thousands):

	Corporation	Partnership	Eliminations	Consolidated
Book income	$101,146	$174,702	$1,055	$276,903
Federal Statutory Rate	35%	0%	0%	
Federal income tax at statutory rate	35,401	—	—	35,401
Permanent items	(116)	—	—	(116)
State income taxes net of federal benefit—				
Corporation	2,433	—	—	2,433
State income taxes—Energy	—	1,617	—	1,617
Current year change in valuation allowance	(120)	—	—	(120)
Provision on income from Class A units(1)	22,484	—	—	22,484
Write-off of deferred income tax assets(2)	7,471	—	—	7,471
Other	(340)	—	—	(340)
Provision for income tax expense	$ 67,213	$ 1,617	$ —	$ 68,830

(1) The Corporation pays tax on its share of the Partnership's income or loss as a result of its ownership of Class A units as discussed in Note 2.

(2) Represents the write-off of certain deferred tax assets that as an indirect result of the Merger will no longer be realized.

16. Income Tax (Continued)

A reconciliation of the actual income tax (benefit) expense and the amount computed by applying the federal statutory rate of 35% to the (loss) income before provision for income tax for the years ended December 31, 2007 and 2006 is as follows (in thousands):

	Year ended December 31, 2007	Year ended December 31, 2006
Federal income tax at statutory rate(1)	$(22,404)	$5,176
Permanent items	12	(61)
State income taxes net of federal benefit—Corporation	(1,797)	273
State income taxes—Energy	168	129
Current year change in valuation allowance	(387)	(341)
Provision on income from Class A units	168	129
Other	(409)	(53)
Provision for income tax (benefit) expense	$(24,649)	$5,252

(1) The calculation of federal income tax at statutory rate has been adjusted for the non-controlling interest in net income of consolidated subsidiary.

16. Income Tax (Continued)

The deferred tax assets and liabilities resulting from temporary book-tax differences are comprised of the following (in thousands):

	December 31, 2008	December 31, 2007
Current deferred tax assets		
Accruals and reserves	$ 99	$ 129
Derivative instruments	—	17,439
Stock compensation	—	273
Current deferred tax assets	99	17,841
Current deferred tax liabilities		
Investment in third party partnerships	—	616
Marketable securities	—	558
Derivative instruments	2,781	—
Current deferred tax liabilities	2,781	1,174
Current subtotal	(2,682)	16,667
Long-term deferred tax assets		
Accruals and reserves	295	—
Participation Plan compensation	—	6,436
Derivative instruments	—	16,270
FIN 48 liability	247	747
Phantom unit compensation	840	—
State net operating loss carryforward	30	53
Long-term deferred tax assets	1,412	23,506
Valuation allowance	(30)	(53)
Net long-term deferred tax assets	1,382	23,453
Long-term deferred tax liabilities		
Property, plant and equipment	5,187	252
Stock compensation	25	56
Investment in consolidated subsidiaries	37,644	31,464
Derivative instruments	5,991	—
Other	—	181
Long-term deferred tax liabilities	48,847	31,953
Long-term subtotal	(47,465)	(8,500)
Net deferred tax (liability) asset	$(50,147)	$ 8,167

Significant judgment is required in evaluating tax positions and determining the Corporation's provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The Corporation establishes reserves for uncertain tax positions based on estimates of whether, and the extent to which, additional taxes will

16. Income Tax (Continued)

be due. These reserves are established when the Corporation believes that certain positions might be challenged despite the Corporation's belief that its tax return positions are fully supportable. The Corporation adjusts these reserves in light of changing facts and circumstances, such as the outcome of tax audits. The provision for income taxes includes the impact of reserve provisions and changes to reserves that are considered appropriate.

The reconciliation of the Corporation's accrual for uncertain tax positions is as follows (in thousands):

	Year ended December 31,	
	2008	2007
Beginning of period	$ 747	$378
Changes to current period tax positions	(500)	369
End of period	$ 247	$747

As of December 31, 2008, changes to the Corporation's uncertain tax positions that are reasonably possible in the next twelve months are not material. As of December 31, 2008, the Corporation had accrued interest and penalties related to uncertain tax positions of $0.2 million, on the Consolidated Balance Sheets. Interest and penalties related to tax contingencies recognized as expense for the year ended December 31, 2008 was $0.1 million.

As of December 31, 2008, the Corporation had state net operating loss carryforwards of approximately $0.9 million that expire between 2011 and 2026. The Corporation expects that future taxable income will likely be apportioned to states other than those in which the net operating loss was generated. As a result, the Corporation believes it is more likely than not that the state net operating losses will not be realized and has provided a 100% valuation allowance against this long-term deferred tax asset. While, the Corporation's consolidated Federal tax return and any significant state tax returns are not currently under examination, the tax years 2004 through 2007 remain open to examination by the major taxing jurisdictions to which the Corporation is subject.

17. Incentive Compensation Plans

As of December 31, 2008, the Partnership had four share-based compensation plans which are administered by the Compensation Committee of the General Partner's board of directors ("Compensation Committee"). Compensation expense is recognized under SFAS No. 123R, *Share-Based Payment* ("SFAS 123R").

Share-based compensation plan	Plan qualification under SFAS 123R	Further awards authorized for issuance under plan
2008 Long-Term Incentive Plan ("2008 LTIP")	Equity awards	Yes
2006 Hydrocarbon Stock Incentive Plan ("2006 Hydrocarbon Plan")	Equity awards	No
Long-Term Incentive Plan ("2002 LTIP")	Liability awards	No
1996 Hydrocarbon Stock Incentive Plan ("1996 Hydrocarbon Plan")	Equity awards	No

17. Incentive Compensation Plans (Continued)

Compensation Expense

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

	Year ended December 31,		
	2008	2007	2006
Phantom units	$11,348	$ 2,080	$ 1,686
Distribution equivalent rights	701	235	198
Restricted stock	75	780	410
Stock options	—	(27)	(9)
General partner interests under Participation Plan	5,470	17,704	20,715
Subordinated units under Participation Plan	—	—	28
Total compensation expense	$17,594	$20,772	$23,028

A distribution equivalent right is a right, granted in tandem with a specific phantom unit, to receive an amount in cash equal to, and at the same time as, the cash distributions made by the Partnership with respect to a unit during the period such phantom unit is outstanding. Payment of distribution equivalent rights associated with units that are expected to vest are recorded as capital distributions, however, payments associated with units that are not expected to vest are recorded as compensation expense.

Compensation expense under the share-based compensation plans has been recorded as either *Selling, general and administrative expenses* or *Facility expenses* in the accompanying Consolidated Statements of Operations.

As of December 31, 2008, total compensation expense not yet recognized related to the unvested awards under the 2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan was approximately $17.5 million, with a weighted average remaining vesting period of approximately 1.1 years. Total compensation expense not yet recognized related to unvested awards under the 2002 LTIP was approximately $0.4 million, with a weighted-average remaining vesting period of approximately 0.8 years. The actual compensation expense recognized for awards under the 2002 LTIP may differ as they qualify as liability awards under SFAS 123R, which are affected by changes in fair value.

2008 LTIP

The 2008 LTIP was approved by unitholders on February 21, 2008. The 2008 LTIP provides 2.5 million common units for issuance to the Corporation's employees and affiliates as share-based payment awards. The 2008 LTIP was created to attract and retain highly qualified officers, directors, and other key individuals and to motivate them to serve the General Partner, the Partnership and their affiliates and to expend maximum effort to improve the business results and earnings of the Partnership and its affiliates. Awards authorized under the 2008 LTIP include unrestricted units, restricted units, phantom units, distribution equivalent rights, and performance awards to be granted in any combination.

In relation to the Merger, 772,500 phantom units have been granted to senior executives and other key employees under the 2008 LTIP during 2008. The phantom units vest on a time-based and

17. Incentive Compensation Plans (Continued)

performance-based schedule over a three year period. Forty percent, or 309,000 phantom units, of the total individual grant is based on continuing employment over the three-year vesting period, and sixty percent, or 463,500 phantom units, of the total individual grant contain performance vesting criteria ("performance units"). As of December 31, 2008, there were 463,500 performance units outstanding, with a grant date fair value of $14.7 million. Vesting of these units occurs if the Partnership achieves established performance goals determined by the Compensation Committee. In accordance with the provisions of SFAS 123R, management will conduct a quantitative analysis on an ongoing basis to assess the probability of meeting the established performance goals and will record compensation expense as required. Compensation expense recorded for the performance units expected to vest was approximately $4.1 million for the year ended December 31, 2008. Compensation expense related to the entire grant of 772,500 phantom units related to the Merger was approximately $9.1 million for the year ended December 31, 2008.

2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan

On February 21, 2008, the 25,897 outstanding shares of restricted stock held by 43 employees and directors granted under the 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan were converted to 49,354 phantom units in connection with the Merger. The conversion qualified as a modification in accordance with SFAS 123R, requiring the Partnership to compare the grant date fair value of the original awards with the converted awards. As a result of the comparison, the Partnership determined that the fair value of the awards had increased by $0.5 million. Approximately $0.4 million of the fair value was expensed in the first quarter; the remaining $0.1 million will be amortized as compensation expense over the remaining vesting period of approximately one year. The converted phantom unit awards will remain outstanding under the terms of the 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan until their respective settlement dates.

Summary of Equity Awards

Under SFAS 123R, awards under the 2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan qualify as equity awards. Accordingly, the fair value is measured at the grant date and is based on the market price of the Partnership's common units. The associated compensation expense related to service-based awards is recognized over the requisite service period, reduced for an estimate of expected forfeitures. Compensation expense related to performance units is recognized when probability of vesting is established, as discussed above. The phantom units, with exception of performance-based awards, generally vest equally over a three year period. A phantom unit entitles an employee to receive a common unit upon vesting. The Partnership generally issues new common units upon vesting of phantom units. As part of a net settlement option, employees may elect to surrender a certain number of phantom units, and in exchange, the Partnership will assume the income tax withholding obligations related to the vesting. Phantom units surrendered for the payment of income tax withholdings will again become available for issuance under the plan from which the awards were initially granted, provided that further awards are authorized for issuance under the plan. The Partnership was required to pay approximately $0.1 million during the year ended December 31, 2008, and zero for the years ended December 31, 2007 and 2006, for income tax withholdings related to the vesting of equity awards. The Partnership received no proceeds from the issuance of phantom units, and none of the phantom units that vested were redeemed by the Partnership for cash.

17. Incentive Compensation Plans (Continued)

The following is a summary of phantom unit activity under the 2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan:

	Number of Units	Weighted-average Grant-date Fair Value
Unvested at January 1, 2008	—	$ —
Granted(1)	928,685	31.78
Vested	(17,274)	31.79
Forfeited	(2,105)	25.92
Unvested at December 31, 2008	909,306	31.80

(1) Includes 49,354 restricted shares converted to phantom units pursuant to the terms of the redemption and merger agreement.

	Year ended December 31,		
	2008	2007	2006
	(in thousands)		
Total grant-date fair value of phantom units granted during the period	$29,516	$822	$863
Total fair value of phantom units vested during the period and total intrinsic value of phantom units settled during the period	$ 549	$406	$159

2002 LTIP

As of December 31, 2008, there were 145,927 phantom units outstanding under the 2002 LTIP; no additional awards will be made under the plan. The phantom units awarded under the 2002 LTIP are classified as liability awards under SFAS 123R. Accordingly, the fair value of the outstanding awards is re-measured at the end of each reporting period based on the market price of the Partnership's common units. The fair value of the phantom units awarded is amortized into earnings as compensation expense over the vesting period, which is generally three years. A phantom unit entitles an employee to receive a common unit upon vesting, or at the discretion of the Compensation Committee, the cash equivalent to the value of a common unit. The Partnership generally issues new common units upon the vesting of phantom units. As part of a net settlement option, employees may elect to surrender a certain number of phantom units, and in exchange, the Partnership will assume the income tax withholding obligations related to the vesting. The Partnership received no proceeds (other than the contributions by the General Partner to maintain its 2% ownership interest prior to the Merger) for issuing phantom units and none of the phantom units that vested were redeemed by the Partnership for cash. The amounts paid by the Partnership for income tax withholdings related to the vesting of awards under the 2002 LTIP were near or at zero for the years ended December 31, 2008, 2007 and 2006.

17. Incentive Compensation Plans (Continued)

The following is a summary of phantom unit activity under the 2002 LTIP:

	Number of Units	Weighted-average Grant-date Fair Value
Unvested at January 1, 2006	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
Granted	78,540	34.00
Vested	(57,214)	26.11
Forfeited	(649)	33.64
Unvested at December 31, 2008	145,927	31.45

	Year ended December 31,		
	2008	2007	2006
	(in thousands)		
Total grant-date fair value of phantom units granted during the period	$2,670	$1,730	$1,994
Total fair value of phantom units vested during the period and total intrinsic value of phantom units settled during the period	$1,943	$1,281	$ 637

Participation Plan

The interests in the Partnership's General Partner sold by the Corporation to certain directors and employees were referred to as the Participation Plan. The Participation Plan was considered a compensatory arrangement and under SFAS 123R, the General Partner interests were classified as liability awards. As a result, the Corporation was required to calculate the fair value of the General Partner interests at the end of each period. In conjunction with the Merger, all of the outstanding interests in the General Partner were acquired for a combination of 0.9 million common units with a fair value of approximately $30.1 million and approximately $21.5 million in cash. As of December 31, 2007, the Participation Plan liability was $47.0 million and is included in *Other long-term liabilities* in the accompanying Consolidated Balance Sheets.

17. Incentive Compensation Plans (Continued)

Hydrocarbon Stock Options

On or before February 21, 2008, the remaining 51,509 Hydrocarbon stock options outstanding were exercised or deemed exercised. The following summarizes the impact of the Corporation's stock options (in thousands):

	Year ended December 31,		
	2008	2007	2006
Options exercised, cashless	1	1	10
Shares issued, cashless	1	1	6
Options exercised, cash	50	13	39
Shares issued, cash	50	13	39

A summary of the status of the Corporation's stock option plan as of December 31, 2008, 2007 and 2006 is presented below.

	Number of Shares	Weighted-average Exercise Price
Outstanding at January 1, 2006	125,409	$7.52
Exercised	(49,999)	7.34
Forfeited	(8,168)	9.00
Expired	(1,607)	7.52
Outstanding at December 31, 2006	65,635	7.48
Exercised	(14,126)	8.46
Outstanding at December 31, 2007	51,509	7.21
Exercised	(51,509)	7.21
Outstanding at December 31, 2008	—	—

For the years ended December 31, 2008, 2007 and 2006, the Corporation received $0.4 million, $0.1 million and $0.3 million, respectively, for the exercise of stock options. The intrinsic value of the options exercised during the years ended December 31, 2008, 2007 and 2006 was $2.9 million, $0.7 million and $1.0 million, respectively. The fair value of the options vesting for the years ended December 31, 2008, 2007 and 2006 was zero, zero and $0.4 million, respectively.

APIC Pool

At the adoption of SFAS 123R, the Partnership elected to adopt the simplified method to establish the beginning balance of the additional paid-in capital pool ("APIC Pool") related to the tax effects of employee share-based compensation, and to determine the subsequent impact on the APIC Pool and Consolidated Statements of Cash Flows of the tax effects of share-based compensation awards that were outstanding upon adoption of SFAS 123R. APIC is reported as common units in the accompanying Consolidated Balance Sheets as a result of the Merger.

SFAS 123R requires that cash flows resulting from tax deductions in excess of the cumulative compensation cost recognized for options exercised be classified as financing cash flows. Previously, all

17. Incentive Compensation Plans (Continued)

tax benefits from stock options had been reported as an operating activity. The Partnership recognized $0.7 million, $0.3 million and $0.2 million for the years ended December 31, 2008, 2007 and 2006, respectively, related to excess tax benefits realized from the exercise of stock options.

18. 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 or purchases of natural gas, NGLs and crude oil. Swaps, futures and option 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 or purchases 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 and purchases, 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 commodity derivative instruments are recorded at fair value in the Consolidated Balance Sheets and Consolidated 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 generally expects those gains and losses to be offset when they become realized. The Partnership does not have any trading derivative financial instruments.

To mitigate its cash flow exposure to fluctuations in the price of NGLs, the Partnership has primarily entered into derivative financial instruments relating to the future price of crude oil. To mitigate its cash flow exposure to fluctuations in the price of natural gas, the Partnership primarily utilizes derivative financial instruments relating to the future price of natural gas. As a result of these transactions, the Partnership has mitigated a significant portion of its expected commodity price risk with agreements primarily expiring at various times through the fourth quarter of 2011. The Partnership has a committee comprised of the senior management team of the general partner 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.

To manage its commodity price risk, the Partnership utilizes a combination of fixed-price forward contracts, fixed-for-floating price swaps, options available in the OTC market, and futures contracts. 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. Due to the timing of purchases and sales, direct exposure to price volatility may result because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Through marketing and derivative activities, direct price exposure may occur naturally or the Partnership may choose direct exposure when it is favorable as compared to the keep-whole risk.

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,

18. Derivative Financial Instruments (Continued)

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.

The Partnership values its derivative instruments and estimates fair value as discussed in Note 5. The Partnership has not designated any of its instruments as cash flow or fair value hedges. The impact of the Partnership's commodity derivative instruments on financial position are summarized below (in thousands):

	December 31, 2008	December 31, 2007
Fair value of derivative instruments:		
Current asset	$126,949	$ 9,441
Noncurrent asset	55,389	5,414
Current liability	(37,633)	(77,426)
Noncurrent liability	(14,801)	(84,051)
Net derivative receivable (payable)	$129,904	$(146,622)

In 2008 the fair value of the Partnership's derivative instruments is inclusive of premium payments of $13.4 million, net of amortization. The Partnership amortizes the premium payments over the effective term of the underlying derivative option contracts through R*ealized (loss) gain—revenue.*

The impact of the Partnership's commodity derivative instruments on the results of operations reported in the accompanying Consolidated Statements of Operations are summarized below (in thousands):

	Year ended December 31,		
	2008	2007	2006
Derivatives:			
Realized (loss) gain—revenue	$(15,704)	$ (15,901)	$ 17
Unrealized gain (loss)—revenue	293,532	(144,069)	10,366
Realized gain (loss)—purchased product costs	7,368	(8,829)	153
Unrealized loss—purchased product costs	(29,739)	(6,363)	(5,842)
Unrealized (loss) gain—facility expenses	(644)	14	—
Total derivative gain (loss)	$254,813	$(175,148)	$ 4,694

For 2008, 2007 and 2006, the *Realized (loss) gain—revenue* includes amortization of premium payments of $2.1 million, $1.0 million and zero, respectively.

The Partnership recognized $28.0 million of net gains resulting from the settlement of a portion of its 2010 and 2011 frac spread positions. The settlement was completed prior to the contractual settlement to improve liquidity and to mitigate credit risk with certain counterparties, and as such does not represent trading activity. $34.6 million of realized gains is included in *Realized (loss) gain—revenue* and $6.6 million of realized loss is included in *Realized gain (loss)—purchased product costs.*

For a description of how the Partnership's derivative instruments are accounted for under SFAS 133 and related interpretations, including how those derivative instruments affect the Partnership's financial position, financial performance, and cash flows see *Derivative Instruments* in Note 2.

19. Employee Benefit Plan

All employees dedicated to, or otherwise principally supporting the Partnership are employees of MarkWest Hydrocarbon, and substantially all of these employees are participants in MarkWest Hydrocarbon's defined contribution benefit plan. The employer matching contribution expense related to this plan was $1.6 million, $1.1 million and $1.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. The plan is discretionary, with annual contributions determined by the General Partner's board of directors.

20. Partners' Capital

As described in Note 3, the Partnership acquired the Corporation through a merger of MWEP, L.L.C. with and into the Corporation, pursuant to which all remaining shares of the Corporation's common stock were converted into approximately 15.5 million Partnership common units. As of December 31, 2008, partners' capital consists of 56,639,952 common limited partner units. The Partnership Agreement stipulates the circumstances under which the Partnership is authorized to issue new capital, maintain capital accounts, and distribute cash.

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.

Distributions of Available Cash

The Partnership distributes all of its Available Cash (as defined) to unitholders of record within 45 days after the end of each quarter. Available Cash is generally defined as all cash and cash equivalents of the Partnership on hand at the end of each quarter, less reserves established by the general partner for future requirements, plus all cash for the quarter from working capital borrowings made after the end of the quarter. The general partner 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.

The quarterly cash distributions and dividends applicable to 2008, 2007 and 2006, were as follows:

Quarter Ended	Record Date	Payment Date	Amount Per Unit
December 31, 2008	February 6, 2009	February 13, 2009	$0.640
September 30, 2008	November 4, 2008	November 14, 2008	$0.640
June 30, 2008	August 4, 2008	August 15, 2008	$0.630
March 31, 2008	May 5, 2008	May 15, 2008	$0.600
December 31, 2007	February 8, 2008	February 15, 2008	$0.189
September 30, 2007	November 9, 2007	November 21, 2007	$0.189
June 30, 2007	August 9, 2007	August 21, 2007	$0.189
March 31, 2007	May 10, 2007	May 22, 2007	$0.168
December 31, 2006	February 9, 2007	February 21, 2007	$0.157
September 30, 2006	November 9, 2006	November 21, 2006	$0.147
June 30, 2006	August 14, 2006	August 21, 2006	$0.126
March 31, 2006	May 26, 2006	June 5, 2006	$0.083

20. Partners' Capital (Continued)

Distributions for the quarter ended December 31, 2007 and all prior periods represent the Corporation's common stock dividends. The per unit amount has been adjusted to reflect the 1.9051 Exchange Ratio to give effect to the Merger on February 21, 2008. The per unit amount has also been adjusted to give effect to the 2006 stock dividend which is discussed below.

Public Offering

On April 14, 2008, the Partnership completed a public offering of 5.75 million newly issued common units, which included the exercise of the overallotment option by the underwriters, representing limited partner interests at a purchase price of $31.15 per common unit. Net proceeds of approximately $171.4 million were used to pay down borrowings under its revolving credit facility of the Partnership Credit Agreement (see Note 15), and the remainder was used to partially fund the Partnership's 2008 capital expenditure requirements.

The following table summarizes the equity offerings that were completed at the Partnership level prior to the Merger (units and $ in millions):

Date of offering	Units issued	Net proceeds
December 18, 2007	2.9	$ 91.8
April 9, 2007	4.1	$137.7
July 6, 2006	6.6	$125.9

Stock Dividend

On April 27, 2006, the Corporation announced that its board of directors approved the issuance of one share of common stock for each ten shares of common stock held by stockholders. The stock was issued on May 23, 2006 to the stockholders of record as of the close of business on May 11, 2006; the ex-dividend date was May 9, 2006.

21. Income (Loss) Per Common Unit

Basic and diluted net income (loss) per common unit is calculated in accordance with SFAS 128. Basic net income (loss) per common unit is calculated by dividing net income (loss) by the weighted-average number of common units outstanding during the period. Diluted net income per common unit is calculated by dividing net income by the weighted-average number of common units outstanding during the period, including potential common units from the vesting of phantom units. Potential common units are excluded from the calculation during periods in which the Partnership incurs a net loss as the impact would be anti-dilutive.

21. Income (Loss) Per Common Unit (Continued)

All unit and per unit data has been adjusted to reflect the Exchange Ratio to give effect to the Merger (see Note 3). The following is a reconciliation of the Corporation common stock outstanding during 2007 and 2006, adjusted to reflect comparable units as a result of the Merger (in thousands):

	Year ended December 31, 2007		Year ended December 31, 2006	
	Adjusted for Merger	As previously reported	Adjusted for Merger	As previously reported
Weighted average common units and shares of common stock, respectively, outstanding during the period	22,854	11,996	22,745	11,939
Effect of dilutive instruments	—	—	179	94
Weighted average common units and shares of common stock, respectively, outstanding during the period including the effects of dilutive instruments	22,854	11,996	22,924	12,033

The following table shows the computation of basic and diluted net income (loss) per common unit, for the years ended December 31, 2008, 2007 and 2006, respectively, and the weighted-average units used to compute diluted net income (loss) per unit. For the year ended December 31, 2007, there is no difference between basic and diluted net loss per unit since phantom units and potential common units from the exercises of stock options were anti-dilutive and were, therefore, excluded from the calculation (in thousands, except per unit data):

	Year ended December 31,		
	2008	2007	2006
Net income (loss)	$208,073	$(39,359)	$ 9,537
Weighted average common units outstanding during the period	51,013	22,854	22,745
Effect of dilutive instruments(1)	547	—	179
Weighted average common units outstanding during the period including the effects of dilutive instruments	51,560	22,854	22,924
Net income (loss) per unit			
Basic	$ 4.08	$ (1.72)	$ 0.42
Diluted	$ 4.04	$ (1.72)	$ 0.42

(1) For the year ended December 31, 2007, 111 units were excluded from the calculation of diluted units, respectively. In accordance with SFAS 128, 309 performance-based units have been excluded from the calculation of diluted units for the year ended December 31, 2008. An additional 155 performance-based units were excluded until the fourth quarter of 2008 when performance targets were achieved.

22. Commitments and Contingencies

Legal

The Partnership is subject to a variety of risks and disputes, and is a party to various legal proceedings in the normal course of its business. The Partnership maintains insurance policies in amounts and with coverage and deductibles as it believes reasonable and prudent. However, the Partnership cannot assure that the insurance companies will promptly honor their policy obligations or that the coverage or levels of insurance will be adequate to protect the Partnership from all material expenses related to future claims for property loss or business interruption to the Partnership, or for third-party claims of personal and property damage, or that the coverages or levels of insurance it currently has will be available in the future at economical prices. While it is not possible to predict the outcome of the legal actions with certainty, management is of the opinion that appropriate provisions and accruals for potential losses associated with all legal actions have been made in the consolidated financial statements.

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, L.L.C. 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 would ultimately recover under the policies. The Defendant insurance companies and MarkWest had each filed separate summary judgment motions in the action. On April 23, 2008, the Court issued an order granting Defendant insurance companies' motion for summary judgment. The Partnership believes the Court's analysis and decision is in error, legally and factually, on numerous grounds and has filed an appeal of this Order to the 10th Circuit Court of Appeals (Case No. 08-1186). The Partnership and the Defendant insurance

22. Commitments and Contingencies (Continued)

companies have filed briefs in connection with the appeal, and oral arguments were presented to the 10th Circuit Court of Appeals on January 15, 2009 and the parties are awaiting the Court's decision.

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); 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 parties in the *Gutierrez* action have been in settlement discussions, have reached an agreement in principle to settle the case for an immaterial amount, and are working towards a final settlement agreement. 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 $12.8 million, $10.3 million and $9.3 million for the years ended December 31, 2008, 2007 and 2006, respectively. The minimum future lease payments under these operating leases as of December 31, 2008, are as follows (in thousands):

Year ending December 31,	
2009	$ 8,148
2010	2,739
2011	1,952
2012	1,898
2013	1,949
2014 and thereafter	4,551
	$21,237

23. Segment Information

The Partnership's chief operating decision maker is the chief executive officer ("CEO"). The CEO reviews the Partnership's discrete financial information on a geographic and operational basis, as the products and services are closely related within each geographic region and business operation. Accordingly, the CEO makes operating decisions, assesses financial performance and allocates resources on a geographical basis. The Partnership has three segments: the Southwest, the Northeast and the Gulf Coast. The Southwest segment provides gathering, processing, transportation, and storage services. The Northeast segment provides processing, transportation, fractionation and storage services. The Gulf Coast segment provides processing, transportation, fractionation and storage services.

The Partnership prepares segment information in accordance with GAAP, except that certain items below *Income (loss) from operations* in the accompanying Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any unrealized gains (losses) from derivative instruments are not allocated to individual segments. Management does not consider these items allocable to or controllable by any individual segment and therefore excludes these items when evaluating segment performance.

As a result of the Merger, segment information for the years ended December 31, 2007 and 2006 has been recast.

The tables below present information about operating income and capital expenditures for the reported segments for the years ended December 31, 2008, 2007 and 2006 (in thousands).

Year ended December 31, 2008:

	Southwest	Northeast	Gulf Coast	Total
Revenue	$652,365	$316,255	$92,042	$1,060,662
Operating expenses:				
Purchased product costs	387,516	228,386	—	615,902
Facility expenses	62,369	22,875	17,368	102,612
Operating income before items not allocated to segments	$202,480	$ 64,994	$74,674	$ 342,148
Capital expenditures(1)	$354,457	$149,547	$66,065	$ 570,069
Capital expenditures not allocated to segments				5,229
Total capital expenditures				$ 575,298

(1) The Southwest segment capital expenditures do not include the $26.7 million of property, plant and equipment acquired in conjunction with the acquisition of PQ Assets.

23. Segment Information (Continued)

Year ended December 31, 2007:

	Southwest	Northeast	Gulf Coast	Total
Revenue	$503,461	$265,152	$77,114	$845,727
Operating expenses:				
Purchased product costs	310,888	177,004	—	487,892
Facility expenses	44,045	16,347	10,471	70,863
Operating income before items not allocated to segments	$148,528	$ 71,801	$66,643	$286,972
Capital expenditures	$295,223	$ 2,988	$14,441	$312,652
Capital expenditures not allocated to segments				3,987
Total capital expenditures				$316,639

Year ended December 31, 2006:

	Southwest	Northeast	Gulf Coast	Total
Revenue	$466,384	$293,964	$68,950	$829,298
Operating expenses:				
Purchased product costs	329,154	231,443	—	560,597
Facility expenses	29,204	17,009	11,190	57,403
Operating income before items not allocated to segments	$108,026	$ 45,512	$57,760	$211,298
Capital expenditures	$ 70,291	$ 2,763	$ 2,748	$ 75,802
Capital expenditures not allocated to segments				4,278
Total capital expenditures				$ 80,080

23. Segment Information (Continued)

The following is a reconciliation of revenue and operating income before items not allocated to segments to net income before non-controlling interest and provision for income tax for the three years ended December 31, 2008, 2007 and 2006 (in thousands):

	Year ended December 31,		
	2008	2007	2006
Total segment revenue	$1,060,662	$ 845,727	$829,298
Derivative gain (loss) not allocated to segments	277,828	(159,970)	10,383
Total revenue	$1,338,490	$ 685,757	$839,681
Operating income before items not allocated to segments	$ 342,148	$ 286,972	$211,298
Derivative gain (loss) not allocated to segments	254,813	(175,148)	4,694
Compensation expense included in facility expenses not allocated to segments	(1,070)	—	—
Selling, general and administrative expenses	(68,975)	(72,484)	(63,360)
Depreciation	(67,480)	(41,281)	(31,010)
Amortization of intangible assets	(38,483)	(16,672)	(16,047)
Loss on disposal of property, plant and equipment	(178)	(7,743)	322
Accretion of asset retirement obligations	(129)	(114)	(102)
Impairment of goodwill and long-lived assets	(36,351)	(356)	—
Income (loss) from operations	384,295	(26,826)	105,795
Earnings from unconsolidated affiliates	90	5,309	5,316
Impairment of unconsolidated affiliate	(41,449)	—	—
Interest income	3,769	4,547	1,574
Interest expense	(64,563)	(39,435)	(40,942)
Amortization of deferred financing costs and discount (a component of interest expense)	(8,299)	(2,983)	(9,229)
Miscellaneous (expense) income	(241)	233	11,984
Income (loss) before non-controlling interest in net income of consolidated subsidiaries and provision for income tax	$ 273,602	$ (59,155)	$ 74,498

23. Segment Information (Continued)

The tables below present information about segment assets as of December 31, 2008 and 2007 (in thousands):

	Southwest	Northeast	Gulf Coast	Total
As of December 31, 2008:				
Total segment assets	$1,487,205	$361,188	$548,503	$2,396,896
Assets not allocated to segments:				
Certain cash and cash equivalents				137
Fair value of derivatives				182,338
Investment in unconsolidated affiliates				46,092
Other(1)				47,591
Total assets				$2,673,054

(1) Includes corporate fixed assets, income tax receivable and other corporate assets not allocated to segments.

	Southwest	Northeast	Gulf Coast	Total
As of December 31, 2007:				
Total segment assets	$780,640	$186,911	$392,937	$1,360,488
Assets not allocated to segments:				
Certain cash and cash equivalents				40,623
Fair value of derivatives				14,855
Investment in unconsolidated affiliates				58,709
Other(1)				50,020
Total assets				$1,524,695

(1) Includes corporate fixed assets, insurance receivable and other corporate assets not allocated to segments.

24. Quarterly Results of Operations (Unaudited)

The following summarizes the Partnership's quarterly results of operations for 2008 and 2007 (in thousands, except per unit data):

	Three months ended			
	March 31	June 30	September 30	December 31
2008				
Revenue	$238,792	$ (34,433)	$566,371	$567,760
Income (loss) from operations	49,361	(213,684)	253,686	294,932
Net income (loss)	19,151	(177,767)	186,546	180,143
Net income (loss) per common unit(1):				
Basic	$ 0.55	$ (3.19)	$ 3.29	$ 3.18
Diluted	$ 0.54	$ (3.19)	$ 3.26	$ 3.14

24. Quarterly Results of Operations (Unaudited) (Continued)

	Three months ended			
	March 31	June 30	September 30	December 31
2007				
Revenue	$177,711	$184,875	$175,548	$147,623
Income from operations	12,135	2,717	7,785	(49,463)
Net income (loss)	957	(7,272)	(7,454)	(25,590)
Net income (loss) per common unit(1)(2):				
Basic	$ 0.04	$ (0.32)	$ (0.33)	$ (1.12)
Diluted	$ 0.04	$ (0.32)	$ (0.33)	$ (1.12)

(1) Basic and diluted net income (loss) per unit are computed independently for each of the quarters presented; therefore, the sum of the quarterly earnings per unit may not equal the total computed for the year. The sum of the quarterly earnings per unit may not equal the annual earnings per unit due to changes in the average units outstanding during the year and the impact of not considering potential common units in the diluted calculation in quarters in which the Partnership reported a net loss.

(2) All historical per unit data has been adjusted to reflect the Exchange Ratio to give effect of the Merger.

The fourth quarter results were significantly impacted by the recognition of realized and unrealized gains on derivative instruments of $340.7 million. The Partnership also recorded an equity impairment of $41.4 million, a goodwill impairment of $28.7 million and an inventory write down of $6.7 million that impacted the fourth quarter results.

25. Valuation and Qualifying Accounts

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

	Year ended December 31,		
	2008	2007	2006
Balance at beginning of period	$194	$156	$ 175
Charged to costs and expenses	(15)	61	141
Other charges(1)	(4)	(23)	(160)
Balance at end of period	$175	$194	$ 156

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

26. Subsequent Events

Liberty Midstream Joint Venture

On January 22, 2009, the Partnership entered into an agreement to form a joint venture with an affiliate of NGP Midstream & Resources, L.P. ("M&R"), a private equity firm focused on investments in selected areas of the energy infrastructure and natural resources sectors. The agreement was executed on February 27, 2009. The joint venture entity, MarkWest Liberty Midstream & Resources, L.L.C. ("Liberty Midstream") operates in the natural gas midstream business in and around the

26. Subsequent Events (Continued)

Marcellus Shale in Pennsylvania and certain counties in West Virginia and Ohio. Under the terms of the joint venture agreement, the Partnership contributed its existing Marcellus Shale natural gas gathering and processing assets to Liberty Midstream, in exchange for a 60% ownership interest. The agreed to value and net book value of the contributed assets is approximately $107.0 million. M&R will make cash contributions of $200.0 million during 2009 in exchange for a 40% ownership interest. The Partnership will make additional capital contributions to Liberty Midstream through a combination of reinvestment of cash distributions received from Liberty Midstream and additional cash capital contributions until the investment balances for the Partnership and M&R are in the ratio of 60% and 40%, respectively. Liberty Midstream is managed by a Board of Managers, which currently consists of three managers designated by the Partnership and two managers designated by M&R. The Partnership will serve as the operator of Liberty Midstream and will provide employees through a services agreement that was entered into at the closing of the joint venture transaction. The Partnership paid transaction costs of approximately $5.0 million associated with the formation of the joint venture.

Amendment to Partnership Credit Agreement

On January 28, 2009, the Partnership also entered into the first amendment to its credit agreement which became effective March 2, 2009. The amendment expands the Partnership's borrowing capacity under the revolving facility by $85.6 million from $350.0 million to $435.6 million, and facilitated the formation of Liberty Midstream. Pursuant to the amendment, the term of the original credit agreement has been reduced by one year and will now be repayable by February 20, 2012. The accordion feature established under the original credit agreement remains at $200.0 million of uncommitted funds. The amendment will also effectively increase the interest rate on the outstanding borrowings by 100 basis points. As described in Note 15, the borrowings under the revolving credit facility of the Partnership Credit Agreement will continue to bear interest at a variable interest rate, plus basis points. The variable interest rate typically is based on the LIBOR; however, in certain borrowing circumstances the rate would be based on the higher of a) the Federal Funds Rate plus 0.5%, and b) a rate set by the Partnership Credit Agreement'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). Under the original agreement, the basis points ranged from 50 to 125 for Base Rate loans, and 150 to 225 for LIBOR loans. Under the new agreement, the basis points range from 150 to 225 for Base Rate loans and 250 to 325 for LIBOR loans. The amendment also established a floor of 2% for the LIBOR rate used to determine the interest rate on the LIBOR loans. The Partnership incurred and capitalized approximately $3.7 million of debt modification fees and other professional services as a result of the amendment in January 2009. The amendment also resulted in the write-off of approximately $0.4 million of previously capitalized deferred finance costs in January 2009.

Early settlement of derivative positions

In January and February 2009, the Partnership settled a portion of its derivative positions covering 2009, 2010 and 2011 for $15.2 million of net gains. The settlement was completed prior to the contractual settlement to improve liquidity and to mitigate credit risk with certain counterparties, and as such does not represent trading activity. $26.5 million of realized gains will be included in Realized (loss) gain—revenue and $11.3 million loss will be included in Realized gain (loss)—purchased product costs. As a result of the settlement, the balances related to these positions are classified as current assets and current liabilities, respectively, in the accompanying Consolidated Balance Sheets.

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 the end of the period covered by this Annual Report on Form 10-K, 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, at a reasonable assurance level, 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.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure Controls will prevent all errors and all fraud. A control system, no matter how well conceived 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. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

Changes in Internal Control Over Financial Reporting

For the quarter ended December 31, 2008, there were material changes to the Partnership's internal controls over financial reporting related to the implementation of the ERP system. 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. The significant changes in business processes and the implementation of the ERP system materially affected the Partnership's internal controls over financial reporting during the quarter ended December 31, 2008. Specifically the Partnership modified controls related to validity and accuracy of contract terms entered into the ERP system. Furthermore, during the quarter ended December 31, 2008, additional gathering systems were migrated from manual processes to the ERP system. While the Partnership believes that this new system and the related changes to internal controls 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 in order to provide certification as of year-end on the effectiveness, in all material respects, of the Partnership's internal controls 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 by or under the supervision of, the Partnership's Chief Executive Officer and Chief Financial Officer and effected by the Partnership's board of director's, 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 in the United States of America and 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 Partnership;
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 Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and
3. 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, 2008. 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, 2008.

The effectiveness of our internal control over financial reporting as of December 31, 2008 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, 2008, 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, 2008, 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, 2008, of the Partnership and our report dated March 2, 2009 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
March 2, 2009

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Information required to be set forth in Item 10. Directors, Executive Officers and Corporate Governance, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2009 Annual Meeting of Unitholders expected to be filed no later than April 30, 2009.

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 2009 Annual Meeting of Unitholders expected to be filed no later than April 30, 2009.

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 2009 Annual Meeting of Unitholders expected to be filed no later than April 30, 2009.

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 2009 Annual Meeting of Unitholders expected to be filed no later than April 30, 2009.

ITEM 14. Principal Accountant Fees and Services

Information required to be set forth in Item 14. Principal Accountant Fees and Services, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2009 Annual Meeting of Unitholders expected to be filed no later than April 30, 2009.

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, L.L.C.

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, L.L.C.

Starfish Pipeline Company, LLC
Consolidated Financial Statements
December 31, 2008 and 2007

Starfish Pipeline Company, LLC
Index
December 31, 2008 and 2007

Report of Independent Auditors

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

In our opinion, the accompanying consolidated balance sheet 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 the results of their operations and their cash flows for the two years 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.

PricewaterhouseCoopers LLP

Houston, Texas
February 22, 2008

Starfish Pipeline Company, LLC
Consolidated Balance Sheets
December 31, 2008* and 2007

(in thousands of dollars)	2008*	2007
Assets		
Current assets		
Cash and cash equivalents	$ 7,861	$ 1,504
Transportation receivables	6,651	3,920
Accrued other receivables (Note 4)	105	343
Other receivables from related parties	8	22
Gas imbalance and gas imbalance net under recoveries (Note 2)	—	491
Other assets	384	418
Total current assets	15,009	6,698
Pipelines, plant and equipment, net (Note 5)	116,021	114,544
Regulatory assets (Note 8)	7,205	2,753
Total assets	$138,235	$123,995
Liabilities and Members' Capital		
Current liabilities		
Accounts payable and accrued liabilities	$ 4,961	$ 2,257
Other payables to related parties	1,389	370
Gas imbalances (Note 2)	3,559	—
Current obligation under capital lease	719	622
Advances from customers	3,387	—
Total current liabilities	14,015	3,249
Obligation under capital lease, less current portion	4,452	5,216
Asset retirement obligation (Note 7)	9,829	5,651
Total liabilities	28,296	14,116
Members' capital	109,939	109,879
Total liabilities and members' capital	$138,235	$123,995

* Not covered by report included herein

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

Starfish Pipeline Company, LLC

Consolidated Statements of Income

Years Ended December 31, 2008*, 2007 and 2006

(in thousands of dollars)	2008*	2007	2006
Operating revenues			
Transportation	$19,217	$27,081	$28,736
Dehydration and other	4,871	5,532	3,342
Total revenues	24,088	32,613	32,078
Operating expenses			
Operating and maintenance	9,296	9,640	12,856
Administrative and general	3,853	1,724	1,922
Depreciation and amortization	9,504	8,946	7,786
Accretion and regulatory expense	310	344	324
Total operating expenses	22,963	20,654	22,888
Net operating income	1,125	11,959	9,190
Other income (expense)			
Interest expense	(404)	(453)	(504)
Interest income	25	183	269
Other income	204	429	546
Total other (expenses) income	(175)	159	311
Net income	$ 950	$12,118	$ 9,501

* Not covered by report included herein

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, 2008*, 2007 and 2006

(in thousands of dollars)	MarkWest (Note 1)	Enbridge (Note 1)	Total
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
Contributions	5,000	5,000	10,000
Distributions	(5,445)	(5,445)	(10,890)
Net income	475	475	950
Balances at December 31, 2008*	$ 54,970	$ 54,969	$109,939

* Not covered by report included herein

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, 2008*, 2007 and 2006

(in thousands of dollars)	2008*	2007	2006
Cash flows from operating activities			
Net income	$ 950	$ 12,118	$ 9,501
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	9,504	8,946	7,786
Accretion and regulatory expense	310	344	324
Provision for bad debts	—	—	(1,422)
Changes in working capital			
Transportation receivables	(2,731)	3,496	473
Other receivables from related parties	14	229	1,235
Gas imbalance net under recoveries	491	1,020	2,717
Accrued other receivables and other assets	(4,180)	703	(1,440)
Accounts payable, accrued liabilities and other liabilities	6,136	(1,528)	(2,708)
Gas imbalances	3,559	(322)	(6,002)
Other payables to related parties	1,019	(2,675)	2,623
Net cash provided by operating activities	15,072	22,331	13,087
Cash flows from investing activities			
Capital expenditures	(7,158)	(1,375)	(27,993)
Acquisition of assets	—	—	(22,747)
Net cash used in investing activities	(7,158)	(1,375)	(50,740)
Cash flows from financing activities			
Contribution from members	10,000	—	39,503
Distribution to members	(10,890)	(21,678)	—
Capital lease payments	(667)	(620)	(578)
Net cash (used in) provided by financing activities	(1,557)	(22,298)	38,925
Increase (decrease) in cash and cash equivalents	6,357	(1,342)	1,272
Cash and cash equivalents			
Beginning of year	1,504	2,846	1,574
End of year	$ 7,861	$ 1,504	$ 2,846

* Not covered by report included herein

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

Starfish Pipeline Company, LLC

Notes to Consolidated Financial Statements

December 31, 2008 (not covered by report included herein) and 2007

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;

1. Organization and Business (Continued)

- 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

As of December 31, 2008 and for the year then ended, the Company does not meet the criteria of a significant subsidiary to MarkWest and as a result, the financial statements for this period are audited but the report is not presented herein.

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 asset retirement and 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.

2. Significant Accounting Policies (Continued)

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 are 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 Company recorded $0 allowance as of December 31, 2008 and 2007.

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.

2. Significant Accounting Policies (Continued)

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

2. Significant Accounting Policies (Continued)

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 $5.9927 per dekatherm ("Dth") for the month of December 2008 and $6.9560 per Dth for the month of December 2007.

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, 2008 and 2007, 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 2008 financial statement presentation, from which the most significant was reclassification of 2007 negative salvage value amounted to $12,474,232 from regulatory liability to accumulated depreciation (Note 8). 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 2008, 2007, and 2006. The total operating and maintenance cost in 2008 and 2007 was $3,055,691 and $2,657,911, respectively. The total general and administrative cost in 2008 and 2007 was $1,821,262 and $1,374,378, respectively. Starfish provides services under an operating agreement to other Enbridge entities. The total service fee received in 2008 and 2007 was approximately $155,000 and $303,000, respectively, which was netted with Starfish operating expenses. At December 31, 2008 and 2007, Starfish had affiliate payables of

3. Related Party Transactions (Continued)

$1,388,836 and $369,507, respectively, and affiliate receivables of $8,274 and $22,360, respectively, 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 $55,960 and $343,285 related to these activities in 2008 and 2007, respectively.

5. Pipelines, Plant and Equipment

Pipelines, plant and equipment at December 31, 2008 and 2007, is comprised of the following:

(in thousands of dollars)	2008	2007
Regulated pipelines and equipment	$ 55,261	$ 66,967
Regulated pipeline under capital lease	9,778	9,778
Unregulated pipelines and equipment	72,923	66,312
Dehydration facilities	5,011	4,349
Construction in progress	2,279	16,004
Asset retirement cost	5,523	1,398
	150,775	164,808
Accumulated depreciation	34,754	50,264
	$116,021	$114,544

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.

6. Capital Lease (Continued)

Future minimum lease payments under capital leases are as follows:

Year Ended December 31, (in thousands of dollars)	
2009	$ 1,073
2010	1,073
2011	1,073
2012	1,073
2013	2,056
Total minimum lease payments	6,348
Less: Amount representing interest	(1,177)
Present value of net minimum lease payments, including current maturities of $719	$ 5,171

7. Asset Retirement Obligation

Activity related to the Company's asset retirement obligation ("ARO") during the year ended December 31, 2008 and 2007, is as follows:

(in thousands of dollars)	2008	2007
Balance of ARO as of January 1	$5,651	$5,936
ARO retirements	(548)	—
Revisions resulting from changes in expected cash flows	4,416	(629)
Accretion expense	310	344
Balance of ARO as of December 31	$9,829	$5,651

For the years ended December 31, 2008, 2007 and 2006, the Company recognized depreciation expense related to its asset retirement cost ("ARC") of $794,801, $505,191 and $512,500, respectively.

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 $265,121, $297,597 and $226,948 was paid to the FERC for fiscal years 2008, 2007 and 2006, respectively. This charge, to be recovered from customers through rates, was recorded as a regulatory asset and will be amortized over twelve months. During 2008, 2007 and 2006, respectively, $289,478, $244,610 and $304,518 was recorded as amortization expense.

8. Regulatory Matters (Continued)

Regulatory Assets

Underfunded ARO

The Company recognizes a regulatory asset or liability for the difference between the historical negative salvage applicable to assets with retirement obligations and the asset retirement obligations recorded under FAS 143. At the end of December 31, 2008 and 2007, the balance of this regulatory asset is $2,540,728 and $2,753,000, respectively. For the Stingray damages, the event surcharge is designed to reimburse Stingray for all repair costs net of insurance proceeds.

Stingray Rate Case Docket No. RP-08-436

On February 11, 2009, the following order was issued by the Federal Energy Regulatory Commission ("FERC") in the Stingray rate case (Docket No. RP08-436): Order of Chief Judge Granting Motion to Place Interim Settlement Rates into Effect. This order places into effect on an interim basis, effective January 1, 2009, the rates and other charges (including an Event Surcharge) resulting from a settlement in principle that is intended to resolve the Stingray rate case. Stingray has the right to reinstate its previous motion rates, effective as of January 1, 2009, if the settlement is not ultimately approved without modification. The FERC has issued a deadline of March 25, 2009, for the participants in the Stingray rate case to file a finalized settlement agreement with the FERC.

- **Negative Salvage Rate**

  Effective January 1, 2009, the negative salvage rate has changed from .25% to .14% under the new Stingray rate case.

- **Maximum Transportation Rate**

  Effective January 1, 2009, the new maximum transportation rate has increased from $.10/Dkt to $.15/Dkt under the new Stingray rate case.

- **Event Surcharge**

  The as-filed Event Surcharge of $0.0145/dth will be effective January 1, 2009. The capital and maintenance expenditures of $4,664,000 related to Hurricane Ike (Note 10), which were incurred by Stingray for the period ended December 31, 2008, have been placed into a regulatory asset account. Those amounts will be collected through the Event Surcharge contemplated by the Stingray rate case settlement in principle. As the Stingray rate case settlement in principle has not yet been finalized or approved by FERC, the amounts to be finally included in this regulatory asset regarding the Event Surcharge may differ from the amounts included in the regulatory asset as of December 31, 2008.

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.

9. Commitments and Contingencies (Continued)

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 Ike

In September 2008, Hurricane Ike caused substantial damage to both onshore and offshore facilities, resulting in loss of revenues and significant capital and maintenance expenditures. As the Company is self insured, the total estimated capital and maintenance expenditures to be incurred amounted to approximately $13,948,000 and $6,469,000, respectively, of which approximately $1,700,000 and $4,000,000, respectively, were incurred as of December 31, 2008.

The members are expected to make contributions to Starfish in 2009 for any capital and maintenance expenditures related to damages caused by Hurricane Ike.

11. Supplemental Cash Flow Disclosures

Cash paid for interest for the years ended December 31, 2008, 2007 and 2006 was approximately $404,390, $453,000 and $495,000, respectively.

Noncash financing and investing activities include:

- A revision resulting from changes in expected cash flows increased the asset retirement obligation and asset retirement cost by $4,415,903 as of December 31, 2008.
- Construction in progress additions and accrued liabilities amount to approximately $966,236, $1,063,000 and $532,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

On November 6, 2008 the members agreed to provide capital contributions in the amount of $10,000,000. Starfish received all the contributions by December 2008.

12. Business and Credit Concentrations

Financial instruments that potentially expose Starfish to concentration of credit risk consist primarily of accounts receivable, which are generally unsecured. For the year ended December 31, 2008, five customers accounted for approximately 44% of transportation revenues and 11% of transportation receivables. 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.

Starfish maintains cash deposits with a major bank, which, from time-to-time, may exceed federally insured limits.

Management does not believe a significant credit risk exists at December 31, 2008.

(3) Exhibits

Exhibit Number	Description
2.1(20)	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(1)	Certificate of Formation of MarkWest Energy Operating Company, L.L.C.
3.3(2)	Amended and Restated Limited Liability Company Agreement of MarkWest Energy Operating Company, L.L.C., dated as of May 24, 2002.
3.4(1)	Certificate of Formation of MarkWest Energy GP, L.L.C.
3.5(2)	Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of May 24, 2002.
3.6(28)	Third Amended and Restated Agreement of Limited Partnership of MarkWest Energy Partners, L.P., dated as of February 21, 2008.
4.1(4)	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.
4.2(6)	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.
4.3(6)	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)
4.4(34)	First Supplemental Indenture, dated as of February 2, 2005, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as Trustee.
4.5(35)	Second Supplemental Indenture, dated as of January 17, 2006, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as Trustee.
4.6*	Third Supplemental Indenture, dated as of March 6, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.7*	Fourth Supplemental Indenture, dated as of April 25, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.8*	Fifth Supplemental Indenture, dated as of August 4, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.9*	Sixth Supplemental Indenture, dated as of September 15, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.

Exhibit Number	Description
4.10(9)	Registration Rights Agreement, dated as of November 9, 2005
4.11(10)	Registration Rights Agreement, dated as of December 23, 2005
4.12(13)	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.
4.13(13)	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.
4.14(13)	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.
4.15*	First Supplemental Indenture, dated as of March 6, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.16*	Second Supplemental Indenture, dated as of April 25, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.17*	Third Supplemental Indenture, dated as of August 4, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.18*	Fourth Supplemental Indenture, dated as of September 15, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.19(14)	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.
4.20(19)	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.
4.21(19)	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.

Exhibit Number	Description
4.22(25)	Unit Purchase Agreement, dated as of December 18, 2007
4.23(25)	Registration Rights Agreement, dated as of December 18, 2007
4.24(28)	Registration Rights Agreement dated as of February 21, 2008 by and among MarkWest Energy Partners, L.P., John M. Fox and MWHC Holding, Inc.
4.25(28)	Registration Rights Agreement dated as of February 21, 2008 by and among MarkWest Energy Partners, L.P. and the holders named therein.
4.26(30)	Indenture dated as of April 15, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the several guarantors named therein, and Wells Fargo Bank, N.A., as trustee.
4.27(30)	Form of 8¾% Series A and Series B Senior Notes due 2018 with attached notation of Guarantees (incorporated by reference to Exhibits A and D of Exhibit 4.23 hereto).
4.28(30)	Registration Rights Agreement dated as of April 15, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, and the several guarantors named therein, and J.P. Morgan Securities Inc., RBC Capital Markets Corporation, Wachovia Capital Markets, LLC, Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Fortis Securities LLC and SunTrust Robinson Humphrey, Inc.
4.29(31)	Registration Rights Agreement dated as of May 1, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, and the several guarantors named therein, and J.P. Morgan Securities Inc., RBC Capital Markets Corporation, Wachovia Capital Markets, LLC, Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Fortis Securities LLC and SunTrust Robinson Humphrey, Inc.
4.30*	First Supplemental Indenture, dated as of April 25, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.31*	Second Supplemental Indenture, dated as of August 4, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.32*	Third Supplemental Indenture, dated as of September 15, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
10.1(2)	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.
10.2(2)	MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.3(2)	First Amendment to MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.4(2)	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.

Exhibit Number	Description
10.5(2)+	Fractionation, Storage and Loading Agreement dated as of May 24, 2002, between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.6(2)+	Gas Processing Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.7(2)+	Pipeline Liquids Transportation Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.8(2)	Natural Gas Liquids Purchase Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.9(3)	Services Agreement dated January 1, 2004 between MarkWest Energy GP, L.L.C. and MarkWest Hydrocarbon, Inc.
10.10(8) △	Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Frank Semple.
10.11(15)	Office Lease Agreement, dated April 19, 2006, by and between Park Central Property LLC, the landlord, and MarkWest Energy Partners, L.P., the tenant.
10.12(17)+	Construction, Operation and Gas Gathering Agreement dated as of September 21, 2006 between MarkWest Western Oklahoma Gas Company, L.L.C. and Newfield Exploration Mid-Continent Inc.
10.13(8) △	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.
10.14(18)	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.
10.15(20)	Exchange Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P., MarkWest Hydrocarbon, Inc., and MarkWest Energy, GP L.L.C.
10.16(20)	Voting Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P. and the Fox Family Holders.
10.17(24)+	Hydrogen Supply Agreement dated September 28, 2007, by and between MarkWest Blackhawk, L.P. and CITGO Refining and Chemicals Company L.P.
10.18(22)	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.

Exhibit Number	Description
10.19(23)	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.
10.20(27)+	Gas Processing Agreement dated as of November 1, 2007, by and between MarkWest Javelina Company and CITGO Refining and Chemicals Company, L.P.
10.21(26)+	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.
10.22(24)	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.
10.23(26)	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.
10.24(27)+	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.
10.25(26)	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.
10.26(26)	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.
10.27(28)	Credit Agreement dated as of February 20, 2008 among MarkWest Energy Partners, L.P., Royal Bank of Canada as Administrative Agent and Collateral Agent, JPMorgan Chase Bank, N.A. and Wachovia Bank, National Association, as Co-Syndication Agents, Fortis Capital Corp., SunTrust Bank and U.S. Bank National Association, as Documentation Agents, RBC Capital Markets, as Sole Lead Arrangers and Sole Book Running Manager, and the lenders party thereto.
10.28(29)	MarkWest Energy Partners, L.P. 2008 Long-Term Incentive Plan.
10.29(32)	Form of Second Amended and Restated Indemnification Agreement dated April 24, 2008 by and among MarkWest Energy Partners, L.P., MarkWest Energy GP, L.L.C., and each director and officer of MarkWest Energy GP, L.L.C., including the following named executive officers: Frank Semple, President and Chief Executive Officer; Nancy Buese, Senior Vice President and Chief Financial Officer; Randy Nickerson, Senior Vice President and Chief Commercial Officer; John Mollenkopf, Senior Vice President and Chief Operations Officer; and C. Corwin Bromley, Senior Vice President, General Counsel and Secretary.
10.30(32)	1996 Stock Incentive Plan for MarkWest Hydrocarbon, Inc.

Exhibit Number	Description
10.31(32)	2006 Stock Incentive Plan for MarkWest Hydrocarbon, Inc.
10.32(33)+	Stiles/Britt Ranch Gas Gathering and Processing Agreement dated effective as of June 12, 2008 and executed August 5, 2008 between Newfield Exploration Mid-Continent Inc. and MarkWest Oklahoma Gas Company, L.L.C.
10.33*+	Natural Gas Liquids Purchase Agreement dated August 25, 2006 between ONEOK Hydrocarbon, L.P. and MarkWest Western Oklahoma Gas Company, L.L.C., now known as MarkWest Oklahoma Gas Company, L.L.C.
10.34*+	Raw Product Purchase Agreement dated February 11, 2005 between MarkWest Energy East Texas Gas Company, L.P., now known as MarkWest Energy East Texas Gas Company, L.L.C., and Dynegy Liquids Marketing and Trade, now known as Targa Liquids Marketing and Trade.
10.35*+	Amendment to the Natural Gas Liquids Purchase Agreement effective as of November 1, 2008 by and between MarkWest Oklahoma Gas Company, L.L.C. and ONEOK Hydrocarbon, L.P.
16.1(23)	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.

(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 June 7, 2002.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(17) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 7, 2006.

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

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

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

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

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

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

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

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

(26) Incorporated by reference to the Annual Report on Form 10-K filed February 29, 2008.

(27) Incorporated by reference to the Annual Report on Form 10-K/A filed May 8, 2008.

(28) Incorporated by reference to the Current Report on Form 8-K filed February 21, 2008.

(29) Incorporated by reference to the Form S-4/A Registration Statement filed December 21, 2007.

(30) Incorporated by reference to the Current Report on Form 8-K filed April 15, 2008.

(31) Incorporated by reference to the Current Report on Form 8-K filed May 1, 2008.

(32) Incorporated by reference to the Quarterly Report on Form 10-Q filed August 11, 2008.

(33) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 10, 2008.

(34) Incorporated by reference to the Form S-4 Registration Statement filed February 22, 2005.

(35) Incorporated by reference to the Form S-4/A Registration Statement filed January 17, 2006.

\+ 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.

△ 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: March 2, 2009 By: /s/ FRANK M. SEMPLE
Frank M. Semple
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities with MarkWest Energy GP, L.L.C., the General Partner of MarkWest Energy Partners, L.P., the Registrant, and on the dates indicated.

Date: March 2, 2009 By: /s/ FRANK M. SEMPLE
Frank M. Semple
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Date: March 2, 2009 By: /s/ NANCY K. BUESE
Nancy K. Buese
Senior Vice President & Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)

Date: March 2, 2009 By: /s/ JOHN M. FOX
John M. Fox
Lead Director

Date: March 2, 2009 By: /s/ KEITH E. BAILEY
Keith E. Bailey
Director

Date: March 2, 2009 By: /s/ MICHAEL L. BEATTY
Michael L. Beatty
Director

Date: March 2, 2009	By: /s/ CHARLES K. DEMPSTER Charles K. Dempster *Director*
Date: March 2, 2009	By: ______________________ Donald C. Heppermann *Director*
Date: March 2, 2009	By: /s/ WILLIAM A. KELLSTROM William A. Kellstrom *Director*
Date: March 2, 2009	By: /s/ ANNE E. MOUNSEY Anne E. Mounsey *Director*
Date: March 2, 2009	By: /s/ WILLIAM P. NICOLETTI William P. Nicoletti *Director*
Date: March 2, 2009	By: ______________________ Donald D. Wolf *Director*

Directors and Officers

Board of Directors of MarkWest Energy GP, LLC

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

Frank M. Semple
Chairman of the Board,
President and Chief Executive Officer
MarkWest Energy GP, LLC

Keith E. Bailey (1) (3)
Chairman of the Audit Committee
Retired Chairman, President and
Chief Executive Officer
The Williams Companies, Inc.

Michael L. Beatty (4)
Chairman of the Nominating and
Corporate Governance
Committee Chairman,
Beatty & Wozniak, PC

Charles K. Dempster (2) (4)
Chairman of the Compensation Committee
Retired Executive
Aquila, Inc.

Donald C. Heppermann (1) (3)
Chairman of the Finance Committee
Retired Chief Financial Officer
MarkWest Energy GP, LLC
MarkWest Hydrocarbon, Inc.

William A. Kellstrom (2) (3)
Retired Executive,
Reliant Energy, Inc.

Anne E. Fox Mounsey (2) (4)
Former Manager
MarkWest Hydrocarbon, Inc.

William P. Nicoletti (1) (3)
Managing Director
Parkman Whaling, LLC

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 Finance Committee
(4) Member of the Nominating and Corporate Governance Committee

Executive Officers of MarkWest Energy GP, LLC

Frank M. Semple
Chairman of the Board,
President and Chief Executive Officer

C. Corwin Bromley
Senior Vice President,
General Counsel and Secretary

Nancy K. Buese
Senior Vice President and
Chief Financial Officer

John C. Mollenkopf
Senior Vice President and
Chief Operations Officer

Randy S. Nickerson
Senior Vice President and
Chief Commercial Officer

Andrew L. Schroeder
Vice President Finance and Treasurer

Contact Information

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Fax: 303.290.8769
Website: www.markwest.com

Investor Relations
Tel: 866.858.0482
Email: investorrelations@markwest.com

Transfer Agent and Registrar

Wells Fargo Shareowner Services
Tel: 800.468.9716
Website: www.shareowneronline.com

Send unitholder inquiries to:
Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, Minnesota 55075

Common Unit Listing

New York Stock Exchange
Ticker Symbol: MWE

NYSE and SEC Certifications

The annual CEO certification required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual was submitted without qualification by Frank M. Semple on July 1, 2008.

MarkWest's Chief Executive Officer and Chief Financial Officer have provided certifications to the U.S. Securities and Exchange Commission as required by Section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as Exhibits 31.1 and 31.2 to the Partnership's Form 10-K for the year ended December 31, 2008.

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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 is committed to help meet the growing demand for environmentally clean energy as a leading midstream service provider for natural gas and natural gas liquids while utilizing ecologically friendly processes and practices.

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.

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Denver, Colorado 80202-2126
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