FORM 10-Q

Quarterly report pursuant to sections 13 or 15(d)

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MARKWEST ENERGY PARTNERS L P

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SIC: **1311** Crude petroleum & natural gas

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2011

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)	(IRS Employer Identification No.)

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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 Exchange Act Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The number of the registrant' s common units outstanding as of October 28, 2011, was 84,939,558.

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Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Forward-Looking Statements" included in Part I, Item 2 for an explanation of these types of assertions. Also, in this document, unless the context requires otherwise, references to "we," "us," "our," "MarkWest Energy" or the "Partnership" are intended to mean MarkWest Energy Partners, L.P., and its consolidated subsidiaries. References to "MarkWest Hydrocarbon" or the "Corporation" are intended to mean

MarkWest Hydrocarbon, Inc., a wholly-owned taxable subsidiary of the Partnership. References to "General Partner" are intended to mean MarkWest Energy GP, L.L.C., the general partner of the Partnership.

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Glossary of Terms

Bbl	Barrel
Bbl/d	Barrels per day
Credit Facility	Revolving credit facility as provided under the Amended and Restated Credit Agreement, dated July 1, 2010, among the Partnership, Wells Fargo Bank, National Association, as administrative agent, RBC Capital Markets, as syndication agent, BNP Paribas, Morgan Stanley Bank and U.S. Bank National Association, as documentation agents, and the lender parties thereto, as supplemented by the Joinder Agreement dated July 29, 2010 and the Joinder Agreement dated June 15, 2011 and as amended by that First Amendment thereto dated as of September 7, 2011.
Dth/d	Dekatherms per day
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Gal	Gallon
Gal/d	Gallons per day
IFRS	International Financial Reporting Standards
Mcf/d	One thousand cubic feet of natural gas per day
MMBtu	One million British thermal units, an energy measurement
MMBtu/d	One million British thermal units per day
MMcf/d	One million cubic feet of natural gas per day
Net operating margin (a non-GAAP financial measure)	Segment revenue less purchased product costs, excluding any derivative gain (loss)
NGL	Natural gas liquids, such as ethane, propane, butanes and natural gasoline
N/A	Not applicable

OTC	Over-the-Counter
SEC	U.S. Securities and Exchange Commission
SMR	Steam methane reformer, operated by a third party and located at the Javelina gas processing and fractionation facility in Corpus Christi, Texas
TSR Performance Units	Phantom units containing performance vesting criteria related to the Partnership' s total shareholder return.
WTI	West Texas Intermediate
VIE	Variable interest entity

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PART I–FINANCIAL INFORMATION

Item 1. Financial Statements

MARKWEST ENERGY PARTNERS, L.P.

Condensed Consolidated Balance Sheets

(unaudited, in thousands)

	September 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents ($72,171 and $2,913, respectively)	$ 159,177	$ 67,450
Restricted cash ($25,143 and $0, respectively)	25,143	–
Receivables, net ($13,451 and $43,783, respectively)	192,271	179,209
Inventories ($21,919 and $8,431, respectively)	43,381	23,432
Fair value of derivative instruments ($280 and $0, respectively)	29,260	4,345
Deferred income taxes	16,090	16,090
Other current assets ($1,168 and $272, respectively)	8,745	8,020
Total current assets	474,067	298,546
Property, plant and equipment ($1,116,112 and $849,986, respectively)	3,121,547	2,613,027
Less: accumulated depreciation ($67,455 and $38,169, respectively)	(401,729)	(294,003)
Total property, plant and equipment, net	2,719,818	2,319,024
Other long-term assets:		
Restricted cash ($3,007 and $28,001, respectively)	3,007	28,001
Investment in unconsolidated affiliate	27,126	28,688

Intangibles, net of accumulated amortization of $157,183 and $124,568, respectively		614,752		613,578
Goodwill		67,918		9,421
Deferred financing costs, net of accumulated amortization of $13,809 and $11,445, respectively		34,043		32,901
Deferred contract cost, net of accumulated amortization of $2,184 and $1,950, respectively		1,066		1,300
Fair value of derivative instruments		42,783		417
Other long-term assets ($361 and $383, respectively)		1,621		1,486
Total assets	$	3,986,201	$	3,333,362
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable ($35,724 and $5,945, respectively)	$	183,695	$	122,473
Accrued liabilities ($68,781 and $64,713, respectively)		168,168		153,869
Deferred income taxes		11		11
Fair value of derivative instruments		65,499		65,489
Total current liabilities		417,373		341,842
Deferred income taxes		28,765		10,427
Fair value of derivative instruments		34,161		66,290
Long-term debt, net of discounts of $1,499 and $1,566, respectively		1,477,963		1,273,434
Other long-term liabilities ($163 and $154, respectively)		118,835		105,349
Commitments and contingencies (Note 11)				
Equity:				
MarkWest Energy Partners, L.P. partners' capital (79,190 and 71,440 common units issued and outstanding, respectively)		1,379,146		1,070,503
Non-controlling interest in consolidated subsidiaries		529,958		465,517
Total equity		1,909,104		1,536,020
Total liabilities and equity	$	3,986,201	$	3,333,362

Asset and liability amounts in parentheses represent the portion of the consolidated balance attributable to VIEs.

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

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MARKWEST ENERGY PARTNERS, L.P.

Condensed Consolidated Statements of Operations

(unaudited, in thousands, except per unit amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Revenue:				
Revenue	$ 400,883	$ 292,370	$ 1,109,632	$ 884,933
Derivative gain (loss)	106,943	(36,959)	61,854	2,707
Total revenue	507,826	255,411	1,171,486	887,640
Operating expenses:				
Purchased product costs	189,284	136,700	497,493	409,119
Derivative (gain) loss related to purchased product costs	(1,274)	19,996	17,866	24,993
Facility expenses	44,236	37,934	124,358	113,266
Derivative gain related to facility expenses	(2,787)	(564)	(2,871)	(436)
Selling, general and administrative expenses	20,162	17,137	60,454	55,064
Depreciation	38,715	31,362	110,280	89,367
Amortization of intangible assets	10,985	10,193	32,632	30,579
Loss on disposal of property, plant and equipment	147	1,937	4,619	2,116
Accretion of asset retirement obligations	557	70	934	282
Total operating expenses	300,025	254,765	845,765	724,350
Income from operations	207,801	646	325,721	163,290
Other income (expense):				
(Loss) earnings from unconsolidated affiliate	(507)	–	(1,262)	1,517
Interest income	62	422	214	1,185
Interest expense	(26,899)	(26,433)	(83,036)	(75,970)
Amortization of deferred financing costs and discount (a component of interest expense)	(1,002)	(3,625)	(3,873)	(8,517)
Derivative gain related to interest expense	–	–	–	1,871
Loss on redemption of debt	(133)	–	(43,461)	–
Miscellaneous (expense) income, net	(4)	76	127	1,129
Income (loss) before provision for income tax	179,318	(28,914)	194,430	84,505
Provision for income tax expense (benefit):				
Current	3,959	3,533	8,104	10,254
Deferred	21,905	(13,771)	18,338	(45)
Total provision for income tax	25,864	(10,238)	26,442	10,209
Net income (loss)	153,454	(18,676)	167,988	74,296
Net income attributable to non-controlling interest	(13,142)	(8,475)	(33,208)	(19,720)
Net income (loss) attributable to the Partnership	$ 140,312	$ (27,151)	$ 134,780	$ 54,576
Net income (loss) attributable to the Partnership' s common unitholders per common unit (Note 14):				
Basic	$ 1.77	$ (0.39)	$ 1.75	$ 0.77
Diluted	$ 1.77	$ (0.39)	$ 1.75	$ 0.77

Weighted average number of outstanding common units:				
Basic	78,619	71,438	76,118	69,685
Diluted	78,760	71,438	76,276	69,831
Cash distribution declared per common unit	$ 0.70	$ 0.64	$ 2.02	$ 1.92

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

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MARKWEST ENERGY PARTNERS, L.P.

Condensed Consolidated Statements of Changes in Equity

(unaudited, in thousands)

	MarkWest Energy Partners, L.P. Unitholders			
	Common Units	Partners' Capital	Non-controlling Interest	Total
December 31, 2010	71,440	$ 1,070,503	$ 465,517	$ 1,536,020
Share-based compensation activity	275	5,213	–	5,213
Excess tax benefits related to share-based compensation	–	1,089	–	1,089
Distributions paid	–	(155,931)	(49,099)	(205,030)
Issuance of units in public offerings, net of offering costs	7,475	323,492	–	323,492
Contributions to MarkWest Liberty Midstream joint venture	–	–	80,332	80,332
Net income	–	134,780	33,208	167,988
September 30, 2011	79,190	$ 1,379,146	$ 529,958	$ 1,909,104

	MarkWest Energy Partners, L.P. Unitholders			
	Common Units	Partners' Capital	Non-controlling Interest	Total
December 31, 2009	66,275	$ 1,096,654	$ 282,739	$ 1,379,393
Share-based compensation activity	278	8,465	–	8,465
Excess tax benefits related to share-based compensation	–	97	–	97
Distributions paid	–	(134,949)	(4,830)	(139,779)
Issuance of units in public offering, net of offering costs	4,887	142,255	–	142,255
Contributions to MarkWest Liberty Midstream joint venture	–	–	148,057	148,057
Net income	–	54,576	19,720	74,296
September 30, 2010	71,440	$ 1,167,098	$ 445,686	$ 1,612,784

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

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MARKWEST ENERGY PARTNERS, L.P.

Condensed Consolidated Statements of Cash Flows

(unaudited, in thousands)

	Nine months ended September 30,	
	2011	2010
Cash flows from operating activities:		
Net income	$ 167,988	$ 74,296
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	110,280	89,367
Amortization of intangible assets	32,632	30,579
Loss on redemption of debt	43,461	–
Amortization of deferred financing costs and discount	3,873	8,517
Accretion of asset retirement obligations	934	282
Amortization of deferred contract cost	234	234
Phantom unit compensation expense	10,611	11,430
Loss (earnings) of unconsolidated affiliate	1,262	(1,517)
Distribution from unconsolidated affiliate	300	2,508
Unrealized gain on derivative instruments	(99,400)	(11,885)
Loss on disposal of property, plant and equipment	4,619	2,116
Deferred income taxes	18,338	(45)
Changes in operating assets and liabilities, net of working capital acquired:		
Receivables	(12,776)	(35,072)
Inventories	(19,470)	576
Other current assets	(725)	2,026
Accounts payable and accrued liabilities	56,716	23,042
Other long-term assets	(284)	(509)
Other long-term liabilities	12,656	1,293
Net cash provided by operating activities	331,249	197,238
Cash flows from investing activities:		
Capital expenditures	(359,926)	(374,173)
Acquisitions	(230,728)	–
Proceeds from disposal of property, plant and equipment	2,968	524
Net cash used in investing activities	(587,686)	(373,649)
Cash flows from financing activities:		
Proceeds from revolving credit facility	1,074,700	421,304
Payments of revolving credit facility	(929,600)	(378,804)

Proceeds from long-term debt	499,000	–
Payments of long-term debt	(440,638)	–
Payments of premiums on redemption of long-term debt	(39,642)	–
Payments for debt issuance costs, deferred financing costs and registration costs	(7,795)	(11,230)
Contributions to MarkWest Liberty Midstream joint venture	80,332	148,057
Payments of SMR liability	(1,390)	(912)
Proceeds from public offerings, net	323,492	142,255
Cash paid for taxes related to net settlement of share-based payment awards	(6,354)	(3,834)
Excess tax benefits related to share-based compensation	1,089	97
Payment of distributions to common unitholders	(155,931)	(134,949)
Payment of distributions to non-controlling interest	(49,099)	(4,830)
Net cash provided by financing activities	348,164	177,154
Net increase in cash	91,727	743
Cash and cash equivalents at beginning of year	67,450	97,752
Cash and cash equivalents at end of period	$ 159,177	$ 98,495

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

MARKWEST ENERGY PARTNERS, L.P.

Notes to the Condensed Consolidated Financial Statements

(unaudited)

1. Organization and Basis of Presentation

MarkWest Energy Partners, L.P. was formed in 2002 as a Delaware limited partnership. The Partnership is 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 extensive natural gas gathering, processing and transmission operations in the southwest, Gulf Coast, and northeast regions of the United States, including the Marcellus Shale, and is the largest natural gas processor and fractionator in the Appalachian region.

These unaudited condensed consolidated financial statements have been prepared in accordance with the rules and regulations of the SEC for interim financial reporting. Accordingly, certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted. These condensed consolidated financial statements should be read in conjunction with the Partnership' s consolidated financial statements included in the Partnership' s Annual Report on Form 10-K for the year ended December 31, 2010. In management' s opinion, the Partnership has made all adjustments necessary for a fair presentation of its results of operations, financial position and cash flows for the periods shown. These adjustments are of a normal recurring nature. Finally, results for the three and nine months ended September 30, 2011 are not necessarily indicative of results for the full year 2011, or any other future period.

The Partnership' s unaudited condensed consolidated financial statements include all majority-owned or majority-controlled subsidiaries. In addition, MarkWest Liberty Midstream & Resources L.L.C. ("MarkWest Liberty Midstream") and MarkWest Pioneer, L.L.C. ("MarkWest Pioneer"), VIEs for which the Partnership has been determined to be the primary beneficiary, are included in the condensed consolidated financial statements (see Note 4). All significant intercompany investments, accounts and transactions have been eliminated. The Partnership' s investment in Centrahoma, LLC, in which the Partnership exercises significant influence but does not control, and is not the primary beneficiary, is accounted for using the equity method.

2. Recent Accounting Pronouncements

In September 2009, the FASB amended the accounting guidance for revenue recognition for multiple-deliverable arrangements. The amended guidance establishes a hierarchy for determining the selling price of each individual deliverable and eliminates the residual value method of allocating the selling price. The amended guidance was effective for the Partnership prospectively for all revenue arrangements entered into or materially modified on or after January 1, 2011. The amendment did not have a material effect on the Partnership' s condensed consolidated financial statements.

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

In September 2011, the FASB amended the accounting guidance for goodwill impairment testing. The amended guidance provides an entity with an option to first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership plans to early adopt the guidance for the period ended December 31, 2011. The adoption of the amended guidance will not have a material effect on the Partnership' s condensed consolidated financial statements.

3. Business Combination

Langley Acquisition

On February 1, 2011, the Partnership acquired natural gas processing and NGL transportation assets from EQT Gathering, LLC, a subsidiary of EQT Corporation (together with all of its affiliates, "EQT"), for a cash purchase price of approximately $230.7 million. The assets acquired include natural gas processing facilities located near Langley, Kentucky, consisting of a cryogenic natural gas processing plant with a capacity of approximately 100 MMcf/d and a refrigeration natural gas processing plant with a capacity of approximately 75 MMcf/d (together, the "Langley Processing Facilities"), a partially constructed NGL pipeline (the "Ranger Pipeline") that will extend through parts of Kentucky and West Virginia, and certain other related assets. The acquired assets do not include certain residue gas compression and transportation facilities at the same location as the Langley Processing Facilities. This acquisition is referred to as the Langley Acquisition. In connection with the Langley Acquisition, the

Partnership will complete the construction of the Ranger Pipeline to connect the Langley Processing Facilities to the Partnership' s existing pipeline that transports NGLs to its Siloam fractionation facility in South Shore, Kentucky.

Concurrently with the closing of the Langley Acquisition, the Partnership entered into a long-term agreement to process certain natural gas owned or controlled by EQT at the Langley Processing Facilities. The processing agreement requires the Partnership to install an additional cryogenic natural gas processing plant with a capacity of at least 60 MMcf/d in 2012. The Partnership exchanges the NGLs produced at the Langley Processing Facilities for fractionated products from its Siloam facility and markets the fractionated products on behalf of EQT in accordance with a long-term NGL exchange and marketing agreement. As a result of the acquisition, the Partnership has significantly expanded its midstream operations in the liquids-rich gas areas of the Appalachian Basin.

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

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

Property, plant and equipment	$	136,525
Goodwill		58,497
Intangibles		33,900
Inventories		1,806
Total	$	230,728

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

Intangible assets consist of an identifiable customer contract and relationship. The acquired intangibles will be amortized on a straight-line basis over the estimated remaining useful life of approximately twelve years.

The results of operations from the Langley Acquisition are included in the condensed consolidated financial statements from the acquisition date. Revenue and net income related to the Langley Acquisition were approximately $6.2 million and $2.1 million, respectively, for the quarter ended September 30, 2011 and $16.3 million and $5.7 million, respectively, for the nine months ended September 30, 2011.

Pro forma financial results that give effect to the Langley Acquisition are not presented as it is impracticable to obtain the necessary information. EQT did not operate the acquired assets as a stand-alone business, and therefore historical financial information that is consistent with the operations under the current agreements is not available or meaningful.

4. Variable Interest Entities

MarkWest Liberty Midstream

MarkWest Liberty Midstream operates in the natural gas midstream business in and around the Marcellus Shale in western Pennsylvania and northern West Virginia. Effective January 1, 2011, equity interests in the entity are owned 51% by the Partnership and 49% by M&R MWE Liberty, LLC ("M&R"), an affiliate of The Energy & Minerals Group and its affiliated funds.

As of September 30, 2011, the cumulative capital contributed to MarkWest Liberty Midstream by each member is proportionate to its respective ownership interest ("Equalization"). However, until the third quarter of 2011, the cumulative capital contributed by M&R had exceeded its ownership interest. Under the terms of the joint venture agreement, M&R received a special $1.3 million allocation of net income from MarkWest Liberty Midstream during the nine months of 2011 due to its excess contributions. The allocation is recorded in *Net income attributable to non-controlling interest*.

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MarkWest Pioneer

MarkWest Pioneer is the owner and operator of the Arkoma Connector Pipeline. Equity interests in the entity are shared equally by the Partnership and Arkoma Pipeline Partners, LLC.

Financial Statement Impact of VIEs

As the primary beneficiary of MarkWest Liberty Midstream and MarkWest Pioneer, the Partnership consolidates the entities and recognizes non-controlling interests. The following tables show the consolidated assets and liabilities attributable to VIEs, excluding intercompany balances, as of September 30, 2011 and December 31, 2010 (in thousands):

	As of September 30, 2011		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ 69,808	$ 2,363	$ 72,171
Restricted cash (current)	25,143	–	25,143
Receivables, net	12,116	1,335	13,451
Inventories	21,919	–	21,919
Fair value of derivative instruments (current)	280	–	280
Other current assets	1,168	–	1,168
Property, plant and equipment, net of accumulated depreciation of $53,468 and $13,987, respectively	906,199	142,458	1,048,657
Restricted cash (long-term)	3,007	–	3,007
Other long-term assets	259	102	361
Total assets	$ 1,039,899	$ 146,258	$ 1,186,157
LIABILITIES			
Accounts payable	$ 35,644	$ 80	$ 35,724
Accrued liabilities	67,849	932	68,781
Other long-term liabilities	91	72	163
Total liabilities	$ 103,584	$ 1,084	$ 104,668

	As of December 31, 2010		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ –	$ 2,913	$ 2,913
Receivables, net	42,181	1,602	43,783
Inventories	8,431	–	8,431
Other current assets	271	1	272
Property, plant and equipment, net of accumulated depreciation of $28,869 and $9,300, respectively	664,778	147,039	811,817

Restricted cash (long-term)	28,001	–	28,001
Other long-term assets	281	102	383
Total assets	$ 743,943	$ 151,657	$ 895,600
LIABILITIES			
Accounts payable	$ 5,945	$ –	$ 5,945
Accrued liabilities	63,450	1,263	64,713
Other long-term liabilities	86	68	154
Total liabilities	$ 69,481	$ 1,331	$ 70,812

The assets of the VIEs are the property of the respective entities and are not available to the Partnership for any other purpose, including as collateral for its secured debt (see Note 9 and Note 16). VIE asset balances can only be used to settle obligations of each respective VIE. The liabilities of the VIEs do not represent additional claims against the Partnership' s general assets, and the creditors or beneficial interest holders of the VIE do not have recourse to the general credit of the Partnership. The Partnership' s Liberty segment includes the results of operations of MarkWest Liberty Midstream and the Partnership' s Southwest segment includes

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the results of operations of MarkWest Pioneer (see Note 15). The cash flow information for MarkWest Liberty Midstream and MarkWest Pioneer comprise substantially all of the cash flow information of the Partnership' s non-guarantor subsidiaries (see Note 16). The Partnership' s maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment, any additional capital contribution commitments and any operating expense incurred by the subsidiary operator in excess of its compensation received for the performance of the operating services. The Partnership did not provide any financial support to the VIEs that it was not contractually obligated to provide during the nine months ended September 30, 2011 and 2010.

5. Derivative Financial Instruments

Commodity Derivatives

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

To mitigate its cash flow exposure to fluctuations in the price of NGLs, the Partnership has entered into derivative financial instruments relating to the future price of NGLs and crude oil. Generally the Partnership hedges its NGL price risk using crude oil as NGL financial markets are not as liquid and historically there has been a strong relationship between changes in NGL and crude oil prices. The pricing relationship between NGLs and crude oil may vary in certain periods due to various market conditions. In periods where NGL prices and crude oil prices are not consistent with the historical relationship, the Partnership incurs increased risk and additional gains or losses. The Partnership enters into NGL derivative contracts when adequate market liquidity exists.

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 and takes into account the partial offset of its long and short gas positions resulting from normal operating activities.

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

The Partnership enters into derivative contracts primarily with financial institutions that are participating members of the Credit Facility and collateral is not posted by the Partnership as the participating members have a collateral position in substantially all the wholly-owned assets of the Partnership. All of the Partnership' s financial derivative positions are currently with participating bank group members. Management conducts a standard credit review on counterparties and the Partnership has agreements containing collateral requirements. For all participating bank group members, collateral requirements do not exist when a derivative contract favors the Partnership. The Partnership uses standardized agreements that allow for offset of positive and negative exposures (master netting arrangements).

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

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As of September 30, 2011, the Partnership had the following outstanding commodity contracts that were entered into to manage cash flow risk associated with future sales of NGLs or future purchases of natural gas.

Derivative contracts not designated as hedging instruments	**Notional Quantity (net)**
Crude oil (bbl)	6,843,759
Natural gas (MMBtu)	14,857,174
NGLs (gal)	138,213,006

Embedded Derivatives in Commodity Contracts

The Partnership has a commodity contract with a producer in the Appalachia region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. This contract is accounted for as an embedded derivative and is recorded at fair value. The changes in fair value of this commodity contract are based on the difference between the contractual and index pricing and are recorded in earnings through *Derivative (gain) loss related to purchased product costs*. In February 2011, the Partnership executed agreements with the producer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022. As of September 30, 2011, the estimated fair value of this contract was a liability of $94.7 million and the recorded value was a liability of $41.1 million. The recorded liability does not include the inception fair value of the commodity contract related to the extended period from April 1, 2015 to December 31, 2022. In accordance with GAAP for non-option embedded derivatives, the fair value of this extended portion of the commodity contract at its inception of February 1, 2011 is deemed to be allocable to the host processing contract and therefore not recorded as a derivative liability. See the following table for a reconciliation of the liability recorded for the embedded derivative as of September 30, 2011 (in thousands).

Fair value of commodity contract	$	94,652
Inception value for period from April 1, 2015 to December 31, 2022		(53,507)
Derivative liability as of September 30, 2011	$	41,145

The Partnership has a commodity contract that gives it an option to fix a component of the utilities cost to an index price on electricity at one of its plant locations through the fourth quarter of 2014. The value of the derivative component of this contract is marked to market through *Derivative gain related to facility expenses*. As of September 30, 2011, the estimated fair value of this contract was an asset of $3.9 million.

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Financial Statement Impact of Derivative Instruments

There were no material changes to the Partnership' s policy regarding the accounting for these instruments as previously disclosed in the Partnership' s Annual Report on Form 10-K for the year ended December 31, 2010. The impact of the Partnership' s derivative instruments on its Condensed Consolidated Balance Sheets and its Condensed Consolidated Statements of Operations is summarized below (in thousands):

Derivative instruments not designated as hedging instruments and their balance sheet location	**Assets**				**Liabilities**			
		September 30, 2011		**December 31, 2010**		**September 30, 2011**		**December 31, 2010**
Commodity contracts								
Fair value of derivative instruments - current	$	29,260	$	4,345	$	(65,499)	$	(65,489)
Fair value of derivative instruments - long-term		42,783		417		(34,161)		(66,290)
Total	$	72,043	$	4,762	$	(99,660)	$	(131,779)

Derivative instruments not designated as hedging instruments and the location of gain or (loss) recognized in income	**Three months ended September 30,**				**Nine months ended September 30,**			
		2011		**2010**		**2011**		**2010**
Revenue: Derivative gain (loss)								
Realized loss	$	(9,809)	$	(1,732)	$	(36,386)	$	(20,551)
Unrealized gain (loss)		116,752		(35,227)		98,240		23,258
Total revenue: derivative gain (loss)		106,943		(36,959)		61,854		2,707
Derivative gain (loss) related to purchased product costs								
Realized loss		(5,989)		(3,946)		(19,436)		(15,117)
Unrealized gain (loss)		7,263		(16,050)		1,570		(9,876)
Total derivative gain (loss) related to purchased product costs		1,274		(19,996)		(17,866)		(24,993)

Derivative gain related to facility expenses				
Unrealized gain	2,787	564	2,871	436
Derivative gain related to interest expense				
Realized gain	–	–	–	2,380
Unrealized loss	–	–	–	(509)
Total derivative gain related to interest expense	–	–	–	1,871
Miscellaneous (expense) income, net				
Unrealized gain	–	103	–	162
Total gain (loss)	$ 111,004	$ (56,288)	$ 46,859	$ (19,817)

At September 30, 2011, the fair value of the Partnership' s commodity derivative contracts is inclusive of premium payments of $1.2 million, net of amortization. For the three months ended September 30, 2011 and 2010, the *Realized loss–revenue* includes amortization of premium payments of $1.2 million and $0.5 million, respectively. For the nine months ended September 30, 2011 and 2010, the *Realized loss–revenue* includes amortization of premium payments of $3.3 million and $1.6 million, respectively.

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6. Fair Value

Fair value measurements and disclosures relate primarily to the Partnership' s derivative positions discussed in Note 5. The following table presents the derivative instruments carried at fair value as of September 30, 2011 and December 31, 2010 (in thousands):

As of September 30, 2011	**Assets**	**Liabilities**
Significant other observable inputs (Level 2)		
Commodity contracts	$ 34,678	$ (53,873)
Significant unobservable inputs (Level 3)		
Commodity contracts	33,458	(4,642)
Embedded derivatives in commodity contracts	3,907	(41,145)
Total carrying value in Condensed Consolidated Balance Sheet	$ 72,043	$ (99,660)

As of December 31, 2010	**Assets**	**Liabilities**
Significant other observable inputs (Level 2)		
Commodity contracts	$ 52	$ (77,776)
Significant unobservable inputs (Level 3)		
Commodity contracts	3,674	(18,031)
Embedded derivatives in commodity contracts	1,036	(35,972)
Total carrying value in Condensed Consolidated Balance Sheet	$ 4,762	$ (131,779)

Changes in Level 3 Fair Value Measurements

The table below includes a rollforward of the balance sheet amounts for the three and nine months ended September 30, 2011 and 2010 for assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy (in thousands).

	Three months ended September 30, 2011	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	$ (22,290)	$ (49,447)
Total gain (realized and unrealized) included in earnings (1)	47,939	8,042
Settlements	3,167	4,167
Fair value at end of period	$ 28,816	$ (37,238)
The amount of total gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ 48,544	$ 8,337

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	Three months ended September 30, 2010		
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Embedded Derivative in Debt Contract
Fair value at beginning of period	$ 5,348	$ (23,636)	$ (131)
Total (loss) or gain (realized and unrealized) included in earnings (1)	(8,952)	(11,977)	103
Settlements (net)	65	2,298	–
Fair value at end of period	$ (3,539)	$ (33,315)	$ (28)
The amount of total (loss) or gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ (8,592)	$ (11,345)	$ 103

	Nine months ended September 30, 2011	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	$ (14,357)	$ (34,936)

Total gain or (loss) (realized and unrealized) included in earnings (1)	35,402	(14,063)
Settlements	7,771	11,761
Fair value at end of period	$ 28,816	$ (37,238)
The amount of total gain or (loss) for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ 39,196	$ (10,813)

	Nine months ended September 30, 2010			
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Interest Rate Contracts	Embedded Derivative in Debt Contract
Fair value at beginning of period	$ (11,340)	$ (34,199)	$ 509	$ (190)
Total gain or (loss) (realized and unrealized) included in earnings (1)	1,319	(6,857)	1,871	162
Settlements (net)	6,482	7,741	(2,380)	–
Fair value at end of period	$ (3,539)	$ (33,315)	$ –	$ (28)
The amount of total (loss) or gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ (2,712)	$ (4,703)	$ –	$ 162

(1) Gains and losses on Commodity Derivative Contracts classified as Level 3 are recorded in *Derivative gain (loss) related to revenue*. Gains and losses on Embedded Derivatives in Commodity Contracts are recorded in *Purchased product costs, Derivative (gain) loss related to purchased product costs and Derivative gain related to facility expenses*. Gains on Embedded Derivatives in Debt Contract are recorded in *Miscellaneous (expense) income, net.* Gains on Interest Rate Contracts are recorded in *Derivative gain related to interest expense*.

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7. Inventories

Inventories consist of the following (in thousands):

	September 30, 2011	December 31, 2010
NGLs	$ 35,567	$ 15,930
Spare parts, materials and supplies	7,814	7,502
Total inventories	$ 43,381	$ 23,432

The increase in NGL inventory primarily relates to the purchase of propane in the Liberty segment. The propane is expected to be sold during the fourth quarter of 2011 and first quarter of 2012.

8. Goodwill

Changes in goodwill are summarized as follows (in thousands):

	Southwest	Northeast	Gulf Coast	Total
Gross goodwill as of December 31, 2010	$ 24,324	$ 3,948	$ 9,854	$ 38,126
Acquisition(1)	–	58,497	–	58,497
Gross Goodwill as of September 30, 2011	24,324	62,445	9,854	96,623
Cumulative impairment (2)	(18,851)	–	(9,854)	(28,705)
Balance as of September 30, 2011	$ 5,473	$ 62,445	$ –	$ 67,918

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

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

9. Long-Term Debt

Debt is summarized below (in thousands):

	September 30, 2011	December 31, 2010
Credit Facility		
Revolving credit facility, 4.25% interest due September 2016	$ 145,100	$ –
Senior Notes (1)		
Senior Notes, 8.5% interest, net of discount of $0 and $642, respectively, issued July 2006 and due July 2016	–	274,358
Senior Notes, 8.75% interest, net of discount of $555 and $924, respectively, issued April and May 2008 and due April 2018	333,807	499,076
Senior Notes, 6.75% interest, issued November 2010 and due November 2020	500,000	500,000
Senior Notes, 6.5% interest, net of discount of $944, issued February and March 2011 and due August 2021	499,056	–
Total long-term debt	$ 1,477,963	$ 1,273,434

(1) The estimated aggregate fair value of the senior notes (collectively, the “Senior Notes”) was approximately $1,350.2 million and $1,333.9 million as of September 30, 2011 and December 31, 2010, respectively, based on quoted market prices.

Credit Facility

On June 15, 2011, the Partnership executed a joinder agreement to the Credit Facility to include an additional member in the bank group and to exercise a portion of the accordion feature under the Credit Facility, thereby increasing the borrowing capacity of the Credit Facility to $745 million and reducing the uncommitted accordion feature to $155 million.

On September 7, 2011, the Partnership amended the Credit Facility, increasing the borrowing capacity of the Credit Facility to $750 million, increasing the uncommitted accordion feature to $250 million, reducing the interest rate ranges by 75 basis points, and extending the maturity date to September 2016.

Under the provisions of the Credit Facility, the Partnership is subject to a number of restrictions and covenants. These covenants are used to calculate the available borrowing capacity on a quarterly basis. The Credit Facility is guaranteed by the Partnership' s wholly-owned subsidiaries and collateralized by substantially all of the Partnership' s assets and those of its wholly-owned subsidiaries. As of September 30, 2011, the Partnership had $27.3 million of letters of credit outstanding under the Credit Facility and approximately $577.6 million available for borrowing.

Senior Notes

On February 24, 2011, the Partnership completed a public offering of $300 million in aggregate principal amount of 6.5% senior unsecured notes ("2021 Senior Notes"), which were issued at par. On March 10, 2011, the Partnership completed a follow-on public offering of an additional $200 million in aggregate principal amount of 2021 Senior Notes, which were issued at 99.5% of par and are treated as a single class of debt securities with the 2021 Senior Notes issued on February 24, 2011. The 2021 Senior Notes mature on August 15, 2021, and interest is payable semi-annually in arrears on February 15 and August 15, commencing August 15, 2011. The Partnership received aggregate net proceeds of approximately $492 million from the 2021 Senior Notes offerings after deducting the underwriting fees and other third-party expenses. The Partnership used the net proceeds from these offerings to fund the repurchase of approximately $272.2 million in aggregate principal amount of the Partnership' s 8.5% senior unsecured notes due 2016 (the "2016 Senior Notes") and approximately $165.6 million in aggregate principal amount of the Partnership' s 8.75% senior unsecured notes due 2018 (the "2018 Senior Notes"). The remaining proceeds were used to repay borrowings under the Credit Facility. The Partnership recorded a pre-tax loss on redemption of debt of approximately $43.3 million in the first quarter of 2011 related to the repurchase of the 2016 Senior Notes and 2018 Senior Notes, which consisted of approximately $3.8 million for the non-cash write off of the unamortized discount and deferred finance costs and approximately $39.5 million for the payment of the related tender premiums and third-party expenses. On July 15, 2011, the Partnership repurchased the remaining 2016 Senior Notes. The Partnership recorded a pre-tax loss on redemption of debt of approximately $0.1 million in the third quarter of 2011 for the payment of tender premiums and third-party expenses related to the repurchase of the remaining 2016 Senior Notes.

10. Equity

Equity Offering

On January 14, 2011, the Partnership completed a public offering of approximately 3.45 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriter' s over-allotment option. Net proceeds after deducting the underwriting fees and third-party offering expenses were approximately $138 million and were used to partially fund the Partnership' s ongoing capital expenditure program, including a portion of the costs associated with the Langley Acquisition (see Note 3).

On July 13, 2011, the Partnership completed a public offering of approximately 4.0 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds after deducting underwriting fees and other third-party offering expenses were approximately $185 million and were used to repay borrowings under the Credit Facility and to partially fund the Partnership' s ongoing capital expenditure program.

Distributions of Available Cash

Quarter Ended	Distribution Per Common Unit	Declaration Date	Record Date	Payment Date
September 30, 2011	$ 0.73	October 18, 2011	November 7, 2011	November 14, 2011

June 30, 2011	$	0.70	July 21, 2011	August 1, 2011	August 12, 2011
March 31, 2011	$	0.67	April 21, 2011	May 2, 2011	May 13, 2011
December 31, 2010	$	0.65	January 27, 2011	February 7, 2011	February 14, 2011

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11. 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 Pipeline and Hazardous Materials Safety Administration issued a Notice of Probable Violation and Proposed Civil Penalty ("NOPV") (CPF No. 2-2006-5001) to both MarkWest Hydrocarbon and Equitable Production Company ("Equitable"). 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 and leased and operated by a subsidiary of the Partnership, 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 $1.1 million. In March 2011, MarkWest received an order assessing a penalty solely against Equitable for count one of the NOPV in the amount of $0.5 million and assessing a penalty jointly and severally against MarkWest and Equitable for four of the other counts in the NOPV in the amount of $0.2 million. In March 2011, the parties filed separate petitions for reconsideration, which remain pending.

In the ordinary course of business, the Partnership is a party to various other legal and regulatory 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.

12. Incentive Compensation Plans

Compensation Expense

Total compensation expense recorded for share-based pay arrangements for the three and nine months ended September 30, 2011 and 2010 is as follows (in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Phantom units	$ 2,518	$ 3,177	$ 10,611	$ 11,430
Distribution equivalent rights	115	548	327	1,169
Total compensation expense	$ 2,633	$ 3,725	$ 10,938	$ 12,599

13. Income Taxes

A reconciliation of the provision for income tax and the amount computed by applying the federal statutory rate to income before provision for income tax for the nine months ended September 30, 2011 and 2010 is as follows (in thousands):

	Nine months ended September 30, 2011			
	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$ 31,993	$ 166,649	$ (4,212)	$ 194,430
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ 11,198	$ –	$ –	$ 11,198
Permanent items	22	–	–	22
State income taxes net of federal benefit	889	848	–	1,737
Provision on income from Class A units (1)	13,359	–	–	13,359
Other	126	–	–	126
Provision for income tax	$ 25,594	$ 848	$ –	$ 26,442

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	Nine months ended September 30, 2010			
	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$ 5,303	$ 83,603	$ (4,401)	$ 84,505
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ 1,856	$ –	$ –	$ 1,856
Permanent items	6	–	–	6
State income taxes net of federal benefit	190	474	–	664
Provision on income from Class A units (1)	8,251	–	–	8,251
Other	(568)	–	–	(568)
Provision for income tax	$ 9,735	$ 474	$ –	$ 10,209

(1) The Corporation and the General Partner of the Partnership own Class A units of the Partnership that were received in the merger of the Corporation and the Partnership completed in February 2008. For further discussion of Class A units, see Item 1. *Business* in the Partnership' s Annual Report on Form 10-K for the year ended December 31, 2010.

14. Earnings (Loss) Per Common Unit

The following table shows the computation of basic and diluted net income (loss) per common unit for the three and nine months ended September 30, 2011 and 2010, and the weighted-average units used to compute diluted net income (loss) per common unit (in thousands, except per unit data):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Net income (loss) attributable to the Partnership	$ 140,312	$ (27,151)	$ 134,780	$ 54,576
Less: Income allocable to phantom units	1,287	370	1,288	921
Income (loss) available for common unitholders	$ 139,025	$ (27,521)	$ 133,492	$ 53,655
Weighted average common units outstanding - basic	78,619	71,438	76,118	69,685

Effect of dilutive instruments (1)	141	–	158	146
Weighted average common units outstanding - diluted (1)	78,760	71,438	76,276	69,831
Net income (loss) attributable to the Partnership' s common unitholders per common unit				
Basic	$ 1.77	$ (0.39)	$ 1.75	$ 0.77
Diluted	$ 1.77	$ (0.39)	$ 1.75	$ 0.77

(1) Dilutive instruments include TSR Performance Units and are based on the number of units, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For the three months ended September 30, 2010, 247 units were excluded from the calculation of diluted units because the impact was anti-dilutive.

15. Segment Information

The Partnership prepares segment information in accordance with GAAP. Certain items below *Income from operations* in the accompanying Condensed Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any gains (losses) from derivative instruments are not allocated to individual segments. Management does not consider these items allocable to or controllable by any individual segment and therefore excludes these items when evaluating segment performance. Segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

The tables below present the Partnership' s segment profit measure, *Operating income before items not allocated to segments*, for the three and nine months ended September 30, 2011 and 2010 and capital expenditures for the nine months ended September 30, 2011 and 2010 for the reported segments (in thousands).

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Three months ended September 30, 2011:	**Southwest**	**Northeast**	**Liberty**	**Gulf Coast**	**Total**
Segment revenue	$ 241,998	$ 55,920	$ 78,586	$ 26,868	$ 403,372
Purchased product costs	141,067	15,947	32,270	–	189,284
Net operating margin	100,931	39,973	46,316	26,868	214,088
Facility expenses	21,043	6,879	9,108	9,798	46,828
Portion of operating income attributable to non-controlling interests	1,227	–	18,223	–	19,450
Operating income before items not allocated to segments	$ 78,661	$ 33,094	$ 18,985	$ 17,070	$ 147,810

Three months ended September 30, 2010:	**Southwest**	**Northeast**	**Liberty**	**Gulf Coast**	**Total**
Segment revenue	$ 159,044	$ 83,400	$ 28,606	$ 21,320	$ 292,370
Purchased product costs	74,835	55,879	5,986	–	136,700
Net operating margin	84,209	27,521	22,620	21,320	155,670
Facility expenses	20,659	5,268	5,668	8,785	40,380
Portion of operating income attributable to non-controlling interests	1,906	–	6,772	–	8,678
Operating income before items not allocated to segments	$ 61,644	$ 22,253	$ 10,180	$ 12,535	$ 106,612

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The following is a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to income (loss) before provision for income tax for the three months ended September 30, 2011 and 2010 (in thousands).

	Three months ended September 30, 2011	Three months ended September 30, 2010
Total segment revenue	$ 403,372	$ 292,370
Derivative gain (loss) not allocated to segments	106,943	(36,959)
Revenue deferral adjustment (1)	(2,489)	–
Total revenue	$ 507,826	$ 255,411
Operating income before items not allocated to segments	$ 147,810	$ 106,612
Portion of operating income attributable to non-controlling interests	19,450	8,678
Derivative gain (loss) not allocated to segments	111,004	(56,391)
Revenue deferral adjustment (1)	(2,489)	–
Compensation expense included in facility expenses not allocated to segments	(263)	(404)
Facility expenses adjustments	2,855	2,850
Selling, general and administrative expenses	(20,162)	(17,137)
Depreciation	(38,715)	(31,362)
Amortization of intangible assets	(10,985)	(10,193)
Loss on disposal of property, plant and equipment	(147)	(1,937)
Accretion of asset retirement obligations	(557)	(70)
Income from operations	207,801	646
Loss from unconsolidated affiliate	(507)	–
Interest income	62	422
Interest expense	(26,899)	(26,433)
Amortization of deferred financing costs and discount (a component of interest expense)	(1,002)	(3,625)
Loss on redemption of debt	(133)	–
Miscellaneous (expense) income, net	(4)	76
Income (loss) before provision for income tax	$ 179,318	$ (28,914)

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is

excluded for segment reporting purposes. For the three months ended September 30, 2011, approximately $0.2 million and $2.3 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

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Nine months ended September 30, 2011:	**Southwest**	**Northeast**	**Liberty**	**Gulf Coast**	**Total**
Segment revenue	$ 679,347	$ 201,687	$ 168,142	$ 73,310	$ 1,122,486
Purchased product costs	373,251	72,527	51,715	–	497,493
Net operating margin	306,096	129,160	116,427	73,310	624,993
Facility expenses	62,055	19,402	22,875	27,100	131,432
Portion of operating income attributable to non-controlling interests	3,745	–	45,782	–	49,527
Operating income before items not allocated to segments	$ 240,296	$ 109,758	$ 47,770	$ 46,210	$ 444,034
Capital expenditures	$ 80,069	$ 17,768	$ 256,877	$ 1,282	$ 355,996
Capital expenditures not allocated to segments					3,930
Total capital expenditures					$ 359,926

Nine months ended September 30, 2010:	**Southwest**	**Northeast**	**Liberty**	**Gulf Coast**	**Total**
Segment revenue	$ 479,051	$ 276,570	$ 66,354	$ 62,958	$ 884,933
Purchased product costs	220,849	179,700	8,570	–	409,119
Net operating margin	258,202	96,870	57,784	62,958	475,814
Facility expenses	60,543	14,555	19,121	23,875	118,094
Portion of operating income attributable to non-controlling interests	4,962	–	15,617	–	20,579
Operating income before items not allocated to segments	$ 192,697	$ 82,315	$ 23,046	$ 39,083	$ 337,141
Capital expenditures	$ 89,949	$ 1,918	$ 275,620	$ 3,418	$ 370,905
Capital expenditures not allocated to segments					3,268
Total capital expenditures					$ 374,173

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The following is a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to income before provision for income tax for the nine months ended September 30, 2011 and 2010 (in thousands).

	Nine months ended September 30,	
	2011	**2010**
Total segment revenue	$ 1,122,486	$ 884,933

Derivative gain not allocated to segments	61,854	2,707
Revenue deferral adjustment (1)	(12,854)	–
Total revenue	$ 1,171,486	$ 887,640
Operating income before items not allocated to segments	$ 444,034	$ 337,141
Portion of operating income attributable to non-controlling interests	49,527	20,579
Derivative gain (loss) not allocated to segments	46,859	(21,850)
Revenue deferral adjustment (1)	(12,854)	–
Compensation expense included in facility expenses not allocated to segments	(1,491)	(1,412)
Facility expenses adjustments	8,565	6,240
Selling, general and administrative expenses	(60,454)	(55,064)
Depreciation	(110,280)	(89,367)
Amortization of intangible assets	(32,632)	(30,579)
Loss on disposal of property, plant and equipment	(4,619)	(2,116)
Accretion of asset retirement obligations	(934)	(282)
Income from operations	325,721	163,290
(Loss) earnings from unconsolidated affiliate	(1,262)	1,517
Interest income	214	1,185
Interest expense	(83,036)	(75,970)
Amortization of deferred financing costs and discount (a component of interest expense)	(3,873)	(8,517)
Derivative gain related to interest expense	–	1,871
Loss on redemption of debt	(43,461)	–
Miscellaneous income, net	127	1,129
Income before provision for income tax	$ 194,430	$ 84,505

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the nine months ended September 30, 2011, approximately $6.9 million and $5.9 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

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The tables below present information about segment assets as of September 30, 2011 and December 31, 2010 (in thousands):

SEGMENT ASSETS:

	September 30, 2011	December 31, 2010
Southwest	$ 1,680,619	$ 1,646,607
Northeast	479,576	244,219
Liberty	1,039,619	743,943
Gulf Coast	569,241	573,456
Total segment assets	3,769,055	3,208,225
Assets not allocated to segments:		
Certain cash and cash equivalents	82,626	49,776
Fair value of derivatives	72,043	4,762
Investment in unconsolidated affiliate	27,126	28,688
Other (1)	35,351	41,911
Total assets	$ 3,986,201	$ 3,333,362

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

16. Supplemental Condensed Consolidating Financial Information

The Partnership has no operations independent of its subsidiaries. As of September 30, 2011, the Partnership' s obligations under the outstanding Senior Notes (see Note 9) were fully and unconditionally guaranteed, jointly and severally, by all of its wholly-owned subsidiaries. MarkWest Liberty Midstream and MarkWest Pioneer, together with certain of the Partnership' s other subsidiaries that do not guarantee the outstanding Senior Notes, have significant assets and operations in aggregate. For the purpose of the following financial information, the Partnership' s investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities. The operations, cash flows and financial position of the co-issuer of the Senior Notes, MarkWest Energy Finance Corporation, are minor and therefore have been included with the Parent' s financial information. Condensed consolidating financial information for the Partnership, its combined guarantor and combined non-guarantor subsidiaries as of September 30, 2011 and December 31, 2010 and for the three and nine months ended September 30, 2011 and 2010 is as follows (in thousands):

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Condensed Consolidating Balance Sheets

	As of September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 3	$ 86,423	$ 72,751	$ –	$ 159,177
Restricted cash	–	–	25,143	–	25,143
Receivables and other current assets	846	222,835	36,806	–	260,487
Intercompany receivables	9,548	8,668	24,505	(42,721)	–
Fair value of derivative instruments	–	28,980	280	–	29,260
Total current assets	10,397	346,906	159,485	(42,721)	474,067

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total property, plant and equipment, net	4,191	1,681,413	1,049,629	(15,415)	2,719,818
Other long-term assets:					
Restricted cash	–	–	3,007	–	3,007
Investment in unconsolidated affiliate	–	27,126	–	–	27,126
Investment in consolidated affiliates	2,659,809	554,896	–	(3,214,705)	–
Intangibles, net of accumulated amortization	–	614,201	551	–	614,752
Fair value of derivative instruments	–	42,783	–	–	42,783
Intercompany notes receivable	215,310	–	–	(215,310)	–
Other long-term assets	33,733	70,554	361	–	104,648
Total assets	$ 2,923,440	$ 3,337,879	$ 1,213,033	$ (3,488,151)	$ 3,986,201
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 8,568	$ 33,807	$ 346	$ (42,721)	$ –
Fair value of derivative instruments	–	65,499	–	–	65,499
Other current liabilities	37,409	209,828	104,637	–	351,874
Total current liabilities	45,977	309,134	104,983	(42,721)	417,373
Deferred income taxes	1,623	27,142	–	–	28,765
Intercompany notes payable	–	192,310	23,000	(215,310)	–
Fair value of derivative instruments	–	34,161	–	–	34,161
Long-term debt, net of discounts	1,477,963	–	–	–	1,477,963
Other long-term liabilities	3,316	115,323	196	–	118,835
Equity:					
MarkWest Energy Partners, L.P. partners' capital	1,394,561	2,659,809	1,084,854	(3,760,078)	1,379,146
Non-controlling interest in consolidated subsidiaries	–	–	–	529,958	529,958
Total equity	1,394,561	2,659,809	1,084,854	(3,230,120)	1,909,104
Total liabilities and equity	$ 2,923,440	$ 3,337,879	$ 1,213,033	$ (3,488,151)	$ 3,986,201

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	As of December 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ –	$ 63,850	$ 3,600	$ –	$ 67,450
Receivables and other current assets	1,708	172,209	52,834	–	226,751
Intercompany receivables	1,440,302	1,099	7,635	(1,449,036)	–
Fair value of derivative instruments	–	4,345	–	–	4,345
Total current assets	1,442,010	241,503	64,069	(1,449,036)	298,546

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total property, plant and equipment, net	4,623	1,512,763	812,898	(11,260)	2,319,024
Other long-term assets:					
Restricted cash	–	–	28,001	–	28,001
Investment in unconsolidated affiliate	–	28,688	–	–	28,688
Investment in consolidated affiliates	716,673	368,864	–	(1,085,537)	–
Intangibles, net of accumulated amortization	–	613,000	578	–	613,578
Fair value of derivative instruments	–	417	–	–	417
Intercompany notes receivable	197,710	–	–	(197,710)	–
Other long-term assets	32,587	12,139	382	–	45,108
Total assets	$ 2,393,603	$ 2,777,374	$ 905,928	$ (2,743,543)	$ 3,333,362
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 672	$ 1,447,799	$ 565	$ (1,449,036)	$ –
Fair value of derivative instruments	–	65,489	–	–	65,489
Other current liabilities	31,882	173,667	70,804	–	276,353
Total current liabilities	32,554	1,686,955	71,369	(1,449,036)	341,842
Deferred income taxes	2,533	7,894	–	–	10,427
Intercompany notes payable	–	197,710	–	(197,710)	–
Fair value of derivative instruments	–	66,290	–	–	66,290
Long-term debt, net of discounts	1,273,434	–	–	–	1,273,434
Other long-term liabilities	3,319	101,852	178	–	105,349
Equity:					
MarkWest Energy Partners, L.P. partners' capital	1,081,763	716,673	834,381	(1,562,314)	1,070,503
Non-controlling interest in consolidated subsidiaries	–	–	–	465,517	465,517
Total equity	1,081,763	716,673	834,381	(1,096,797)	1,536,020
Total liabilities and equity	$ 2,393,603	$ 2,777,374	$ 905,928	$ (2,743,543)	$ 3,333,362

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Condensed Consolidating Statements of Operations

	Three Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 425,142	$ 82,684	$ –	$ 507,826
Operating expenses:					
Purchased product costs	–	155,612	32,398	–	188,010
Facility expenses	–	31,351	10,263	(165)	41,449
Selling, general and administrative expenses	11,270	7,768	2,421	(1,297)	20,162
Depreciation and amortization	182	38,391	11,314	(187)	49,700

Other operating expenses	–	1,069	(365)	–	704
Total operating expenses	11,452	234,191	56,031	(1,649)	300,025
(Loss) income from operations	(11,452)	190,951	26,653	1,649	207,801
Earnings from consolidated affiliates	174,458	13,479	–	(187,937)	–
Loss on redemption of debt	(133)	–	–	–	(133)
Other expense, net	(20,609)	(4,849)	(32)	(2,860)	(28,350)
Income before provision for income tax	142,264	199,581	26,621	(189,148)	179,318
Provision for income tax expense	741	25,123	–	–	25,864
Net income	141,523	174,458	26,621	(189,148)	153,454
Net income attributable to non-controlling interest	–	–	–	(13,142)	(13,142)
Net income attributable to the Partnership	$ 141,523	$ 174,458	$ 26,621	$ (202,290)	$ 140,312

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	Three Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 222,004	$ 33,407	$ –	$ 255,411
Operating expenses:					
Purchased product costs	–	150,689	6,007	–	156,696
Facility expenses	–	30,931	6,602	(163)	37,370
Selling, general and administrative expenses	12,203	4,842	1,354	(1,262)	17,137
Depreciation and amortization	147	34,400	7,117	(109)	41,555
Other operating expenses	730	1,269	8	–	2,007
Total operating expenses	13,080	222,131	21,088	(1,534)	254,765
(Loss) income from operations	(13,080)	(127)	12,319	1,534	646
Earnings from consolidated affiliates	9,249	4,256	–	(13,505)	–
Other (expense) income, net	(21,539)	(5,097)	412	(3,336)	(29,560)
(Loss) income before provision for income tax	(25,370)	(968)	12,731	(15,307)	(28,914)
Provision for income tax benefit	(21)	(10,217)	–	–	(10,238)
Net (loss) income	(25,349)	9,249	12,731	(15,307)	(18,676)
Net income attributable to non-controlling interest	–	–	–	(8,475)	(8,475)
Net (loss) income attributable to the Partnership	$ (25,349)	$ 9,249	$ 12,731	$ (23,782)	$ (27,151)

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	Nine Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 991,993	$ 179,493	$ –	$ 1,171,486
Operating expenses:					
Purchased product costs	–	463,459	51,900	–	515,359
Facility expenses	–	95,701	26,285	(499)	121,487
Selling, general and administrative expenses	35,348	23,139	6,390	(4,423)	60,454
Depreciation and amortization	538	112,868	30,010	(504)	142,912
Other operating expenses	673	4,895	(15)	–	5,553
Total operating expenses	36,559	700,062	114,570	(5,426)	845,765
(Loss) income from operations	(36,559)	291,931	64,923	5,426	325,721
Earnings from consolidated affiliates	287,377	31,623	–	(319,000)	–
Loss on redemption of debt	(43,461)	–	–	–	(43,461)
Other expense, net	(67,574)	(10,583)	(92)	(9,581)	(87,830)
Income before provision for income tax	139,783	312,971	64,831	(323,155)	194,430
Provision for income tax expense	848	25,594	–	–	26,442
Net income	138,935	287,377	64,831	(323,155)	167,988
Net income attributable to non-controlling interest	–	–	–	(33,208)	(33,208)
Net income attributable to the Partnership	$ 138,935	$ 287,377	$ 64,831	$ (356,363)	$ 134,780

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	Nine Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 807,585	$ 80,055	$ –	$ 887,640
Operating expenses:					
Purchased product costs	–	425,469	8,643	–	434,112
Facility expenses	–	91,074	22,245	(489)	112,830
Selling, general and administrative expenses	35,243	19,370	4,141	(3,690)	55,064
Depreciation and amortization	438	101,034	18,739	(265)	119,946
Other operating expenses	730	1,364	304	–	2,398
Total operating expenses	36,411	638,311	54,072	(4,444)	724,350
(Loss) income from operations	(36,411)	169,274	25,983	4,444	163,290
Earnings from consolidated affiliates	156,634	7,521	–	(164,155)	–
Other (expense) income, net	(60,675)	(10,427)	1,258	(8,941)	(78,785)
Income before provision for income tax	59,548	166,368	27,241	(168,652)	84,505

Provision for income tax expense	475	9,734	–	–	10,209
Net income	59,073	156,634	27,241	(168,652)	74,296
Net income attributable to non-controlling interest	–	–	–	(19,720)	(19,720)
Net income attributable to the Partnership	$ 59,073	$ 156,634	$ 27,241	$ (188,372)	$ 54,576

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Condensed Consolidating Statements of Cash Flows

	Nine Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$ (89,044)	$ 303,401	$ 121,551	$ (4,659)	$ 331,249
Cash flows from investing activities:					
Capital expenditures	(785)	(100,155)	(264,996)	6,010	(359,926)
Acquisitions	–	(230,728)	–	–	(230,728)
Equity investments	(34,246)	(204,428)	–	238,674	–
Distributions from consolidated affiliates	37,978	50,019	–	(87,997)	–
Investment in intercompany notes, net	(17,600)	–	–	17,600	–
Proceeds from disposal of property, plant and equipment	–	365	3,954	(1,351)	2,968
Net cash used in investing activities	(14,653)	(484,927)	(261,042)	172,936	(587,686)
Cash flows from financing activities:					
Proceeds from revolving credit facility	1,074,700	–	–	–	1,074,700
Payments of revolving credit facility	(929,600)	–	–	–	(929,600)
Proceeds from long-term debt	499,000	–	–	–	499,000
Payments of long-term debt	(440,638)	–	–	–	(440,638)
Payments of premiums on redemption of long-term debt	(39,642)	–	–	–	(39,642)
(Payments of) proceeds from intercompany notes, net	–	(5,400)	23,000	(17,600)	–
Payments for debt issuance costs, deferred financing costs and registration costs	(7,795)	–	–	–	(7,795)
Contributions to guarantor subsidiaries, net	–	34,246	–	(34,246)	–
Contributions to joint ventures, net	–	–	284,760	(204,428)	80,332
Payments of SMR liability	–	(1,390)	–	–	(1,390)
Proceeds from public equity offering, net	323,492	–	–	–	323,492
Share-based payment activity	(6,354)	1,089	–	–	(5,265)
Payment of distributions	(155,931)	(37,978)	(99,118)	87,997	(205,030)
Intercompany advances, net	(213,532)	213,532			
Net cash provided by financing activities	103,700	204,099	208,642	(168,277)	348,164
Net increase in cash	3	22,573	69,151	–	91,727
Cash and cash equivalents at beginning of year	–	63,850	3,600	–	67,450

Cash and cash equivalents at end of period	$ 3	$ 86,423	$ 72,751	$ –	$ 159,177

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	Nine Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$ (63,740)	$ 230,279	$ 35,460	$ (4,761)	$ 197,238
Cash flows from investing activities:					
Capital expenditures	(569)	(97,039)	(281,326)	4,761	(374,173)
Equity investments	(32,442)	(130,074)	–	162,516	–
Distributions from consolidated affiliates	33,237	14,512	–	(47,749)	–
Payments for intercompany notes, net	(1,550)	–	–	1,550	–
Proceeds from disposal of property, plant and equipment	–	524	–	–	524
Net cash used in investing activities	(1,324)	(212,077)	(281,326)	121,078	(373,649)
Cash flows from financing activities:					
Proceeds from revolving credit facility	421,304	–	–	–	421,304
Payments of revolving credit facility	(378,804)	–	–	–	(378,804)
Proceeds from intercompany notes, net	–	1,550	–	(1,550)	–
Payments for debt issuance costs, deferred financing costs and registration costs	(11,230)	–	–	–	(11,230)
Contributions from parent, net	–	32,442	–	(32,442)	–
Contributions to joint ventures, net	–	–	278,131	(130,074)	148,057
Payments of SMR liability	–	(912)	–	–	(912)
Proceeds from public offering, net	142,255	–	–	–	142,255
Share-based payment activity	(3,834)	97	–	–	(3,737)
Payment of distributions	(134,949)	(33,237)	(19,342)	47,749	(139,779)
Intercompany advances, net	30,322	(30,322)	–	–	–
Net cash provided by (used in) financing activities	65,064	(30,382)	258,789	(116,317)	177,154
Net (decrease) increase in cash	–	(12,180)	12,923	–	743
Cash and cash equivalents at beginning of year	–	74,448	23,304	–	97,752
Cash and cash equivalents at end of period	$ –	$ 62,268	$ 36,227	$ –	$ 98,495

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17. Supplemental Cash Flow Information

The following table provides information regarding supplemental cash flow information (in thousands).

	Nine months ended September 30,	
	2011	2010
Supplemental disclosures of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ 76,876	$ 64,448
Cash paid for income taxes, net of refunds	5,051	8,760
Supplemental schedule of non-cash investing and financing activities:		
Accrued property, plant and equipment	$ 85,666	$ 53,381
Interest capitalized on construction in progress	571	2,719
Issuance of common units for vesting of share-based payment awards	5,412	7,238

18. Subsequent Events

Equity Offering

On October 13, 2011, the Partnership completed a public offering of approximately 5.75 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds after deducting underwriting fees and other third-party expenses were approximately $251 million and were used to repay borrowings under the Credit Facility and to provide working capital for general partnership purposes.

Senior Notes Offering and Tender Offer

On October 25, 2011, the Partnership commenced a public offering of $700 million in aggregate principal amount of 6.25% senior unsecured notes due June 2022 ("2022 Senior Notes"). The offering is expected to close on November 3, 2011. Interest on the 2022 Notes is payable semi-annually in arrears on June 15 and December 15, commencing June 15, 2012. The Partnership intends to use the net proceeds from this offering to fund the repurchase of any and all of the $334.4 million outstanding 2018 Senior Notes that are tendered pursuant to a concurrent tender offer, and any remaining net proceeds will be used to provide additional working capital for general partnership purposes. The Partnership has offered to repurchase the 2018 Senior Notes at 112.5% of their principal amounts for all notes tendered prior to November 9, 2011. Any 2018 Senior Notes tendered after November 9, 2011 but prior to November 25, 2011 will be repurchased at 109.5% of their principal amounts.

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Item 2. Management' s Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

Management' s Discussion and Analysis ("MD&A") contains statements that are forward-looking and should be read in conjunction with our condensed consolidated financial statements and accompanying notes included elsewhere in this report and our Annual Report on Form 10-K for the year ended December 31, 2010. Statements that are not historical facts are forward- looking statements. We use words such as "could," "may," "predict," "should," "expect," "hope," "continue," "potential," "plan," "intend," "anticipate," "project," "believe," "estimate," and similar expressions to identify forward-looking statements. These statements are based on current expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. Forward-looking statements are not guarantees and actual results could differ materially from those expressed or implied in the forward-looking statements as a result of a number of factors. We do not update publicly any forward-looking statement with new information or future events. Undue reliance should not be placed on forward-looking statements as many of these factors are beyond our ability to control or predict.

Overview

We are a master limited partnership engaged in the gathering, transportation and processing of natural gas; the transportation, fractionation, marketing and storage of NGLs; and the gathering and transportation of crude oil. We have extensive natural gas gathering, processing and transmission operations in the southwest, Gulf Coast and northeast regions of the United States, including the Marcellus Shale, and are the largest natural gas processor and fractionator in the Appalachian region.

Significant Financial and Other Highlights

Significant financial and other highlights for the three months ended September 30, 2011 are listed below. Refer to *Results of Operations* and *Liquidity and Capital Resources* for further details.

- Total segment operating income before items not allocated to segments (a non-GAAP financial measure, see below) increased approximately $41.2 million, or 39%, for the three months ended September 30, 2011 compared to the same period in 2010. The increase is due primarily to higher commodity prices in 2011, expanding operations in our Liberty and Northeast segments and increased volumes from a large producer in our Southwest segment. The increase was partially offset by a $10.1 million increase in cash paid for the settlement of commodity derivative positions.

- In July 2011, we received net proceeds of approximately $185 million from a public offering of approximately 4.0 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option.

- In September 2011, we commenced operations of our fractionation facility in Houston, Pennsylvania. The new fractionation facility allows us to provide additional fully-integrated midstream services to our producer customers in the Marcellus Shale.

Non-GAAP Financial Measures

In evaluating the Partnership' s financial performance, management utilizes the segment performance measures, segment revenues and operating income before items not allocated to segments. These financial measures are presented in Note 15 to the accompanying condensed consolidated financial statements and are considered non-GAAP financial measures when presented outside of the notes to the condensed consolidated financial statements. The use of these measures allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. See Note 15 to the accompanying condensed consolidated financial statements for the reconciliations of segment revenue and operating income before items not allocated to segments to the respective most comparable GAAP measure.

Management evaluates contract performance on the basis of net operating margin (a non-GAAP financial measure) which is defined as segment revenue, excluding any derivative gain (loss) and adjusted for the non-cash impact of revenue deferrals related to certain agreements, less purchased product costs, excluding any derivative gain (loss). These adjustments have been made 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.

The following is a reconciliation to *Income from operations*, the most comparable GAAP financial measure to net operating margin (in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Segment revenue	$ 403,372	$ 292,370	$ 1,122,486	$ 884,933
Purchased product costs	(189,284)	(136,700)	(497,493)	(409,119)
Net operating margin	214,088	155,670	624,993	475,814
Facility expenses	(44,236)	(37,934)	(124,358)	(113,266)
Derivative gain (loss)	111,004	(56,391)	46,859	(21,850)
Revenue deferral adjustment	(2,489)	−	(12,854)	−
Selling, general and administrative expenses	(20,162)	(17,137)	(60,454)	(55,064)
Depreciation	(38,715)	(31,362)	(110,280)	(89,367)
Amortization of intangible assets	(10,985)	(10,193)	(32,632)	(30,579)
Loss on disposal of property, plant and equipment	(147)	(1,937)	(4,619)	(2,116)
Accretion of asset retirement obligations	(557)	(70)	(934)	(282)
Income from operations	$ 207,801	$ 646	$ 325,721	$ 163,290

Segment revenues, operating income before items not allocated to segments and net operating margin (collectively the "Non-GAAP Measures") do not have any standardized definition and therefore are unlikely to be comparable to similar measures presented by other reporting companies. Non-GAAP Measures should not be evaluated in isolation of, or as a substitute for, our financial results prepared in accordance with GAAP. Non-GAAP Measures and the underlying methodology in excluding certain revenues or charges is not necessarily an indication of the results of operations expected in the future, or that we will not, in fact, receive such revenue or incur such charges in future periods.

Our Contracts

We generate the majority of our revenue and net operating margin (a non-GAAP measure, see above 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 following types of arrangements: fee-based, percent-of-proceeds, percent-of-index and keep-whole. See Item 1. *Business−Our Contracts* in our Annual Report on Form 10-K for the year ended December 31, 2010 for further discussion of each of these types of arrangements.

The following table does not give effect to our active commodity risk management program. For the nine months ended September 30, 2011, we calculated the following approximate percentages of our segment revenue and net operating margin from the following types of contracts:

	Fee-Based	Percent-of-Proceeds (1)	Percent-of-Index (2)	Keep-Whole (3)
Segment revenue	21%	38%	4%	37%
Net operating margin (4)	38%	30%	0%	32%

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

(2) Includes arrangements tied to natural gas prices.

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

(4) We manage our business by taking into account the partial offset of short natural gas positions by long positions primarily in our Southwest segment. The calculated percentages for the net operating margin for percent-of-proceeds, percent-of-index and keep-whole contracts reflect the partial offset of our natural gas positions.

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 our Northeast segment operations, 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. These seasonal factors also impact our Liberty segment; however, we anticipate that the expected growth and expansion in our Liberty segment in 2011 will counteract this seasonality impact.

Results of Operations

Segment Reporting

We classify our business in four reportable segments: Southwest, Northeast, Liberty and Gulf Coast. We present information in this MD&A by segment. The segment information appearing in Note 15 of the accompanying Notes to the Condensed Consolidated Financial Statements is presented on a basis consistent with our internal management reporting.

Southwest

- *East Texas.* We own a system that consists of natural gas gathering pipelines, centralized compressor stations, 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, Travis Peak and Haynesville formations. Our current cryogenic processing capacity in East Texas is 280 MMcf/d, and we are planning an additional 120 MMcf/d cryogenic processing plant that is expected to be complete in the fourth quarter of 2012. For natural gas that is processed in this area, we purchase the NGLs from the producers under percent-of-proceeds arrangements, or we transport and process volumes for a fee.

- *Oklahoma.* We own a natural gas gathering system in the Woodford Shale play in the Arkoma Basin of southeast Oklahoma. The liquids- rich natural gas gathered in the Woodford system is processed through Centrahoma Processing LLC (“Centrahoma”), our equity investment or another third-party processor. In addition, we own the Foss Lake natural gas gathering system and the Western Oklahoma natural gas processing complex, all located in Roger Mills, Beckham, 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. The majority of the gathered gas ultimately is compressed and delivered to the processing plants. We also own a gathering system in the Granite Wash formation in the Texas panhandle that is connected to our Western Oklahoma processing complex. We completed the expansion of the Western Oklahoma natural gas processing plant in October 2011, which increased our processing capacity at the Western Oklahoma complex by 75 MMcf/d to a total of 235 MMcf/d. The gathering and processing expansions are supported by long-term agreements with producer customers.

Through our joint venture, MarkWest Pioneer, we operate the Arkoma Connector Pipeline, a 50-mile FERC-regulated pipeline that interconnects with the Midcontinent Express Pipeline and Gulf Crossing Pipeline at Bennington, Oklahoma and is designed to provide approximately 638,000 Dth/d of Woodford Shale takeaway capacity.

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

Northeast

- *Kentucky and southern West Virginia.* Our Northeast segment assets include the Kenova, Boldman, Cobb, Kermit and the Langley natural gas processing plants acquired in the first quarter of 2011, an NGL pipeline, and the Siloam NGL fractionation plant. In connection with the Langley Acquisition, we will complete the construction of the Ranger Pipeline to connect the Langley Processing Facilities to our existing NGL pipeline that transports NGLs to our Siloam fractionation facility. We have an obligation to install an additional cryogenic natural gas processing plant with a capacity of at least 60 MMcf/d in 2012. In addition, we have two caverns for storing propane at our Siloam facility and additional propane storage capacity under a long-term firm-capacity agreement with a third party. The Northeast segment operations include fractionation and marketing services on behalf of the Liberty segment. Including our presence in the Marcellus shale, we are the largest processor and fractionator of natural gas in the Northeast, with fully integrated processing, fractionation, storage and marketing operations.

- *Michigan.* We own and operate a FERC-regulated crude oil pipeline in Michigan providing transportation service for three shippers.

Liberty

- *Marcellus Shale.* We provide extensive natural gas midstream services in southwestern Pennsylvania and northern West Virginia through MarkWest Liberty Midstream. With gathering capacity of 325 MMcf/d and current processing capacity of 625 MMcf/d, we are the largest processor of natural gas in the Marcellus Shale, with fully integrated gathering, processing, fractionation, storage and marketing operations that are critical to the liquids-rich gas development in the northeast United States.

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

  Processing

  - 355 MMcf/d of current cryogenic processing capacity at our Houston, Pennsylvania processing complex (“Houston Complex”), which includes a 200 MMcf/d cryogenic plant that began operations in the second quarter of 2011.

- 270 MMcf/d of current cryogenic processing capacity at our Majorsville, West Virginia processing complex "(Majorsville Complex"), which includes a 135 MMcf/d cryogenic plant that began operations in the second quarter of 2011.
- 320 MMcf/d cryogenic processing capacity under construction in Mobley, West Virginia ("Mobley Complex") where 120 MMcf/d and 200 MMcf/d cryogenic plants are expected to be completed in the first and second half of 2012, respectively.
- 200 MMcf/d cryogenic processing capacity under construction in Sherwood, West Virginia that is expected to be completed in the second half of 2012.

By the end of 2012, MarkWest Liberty Midstream is expected to have more than 1Bcf/d of cryogenic processing capacity that is supported by long-term agreements with our producer customers. NGLs produced at the Majorsville Complex are transported through an NGL pipeline to the Houston Complex ("Majorsville Pipeline") for fractionation. We also plan to complete an NGL pipeline connecting each of the planned processing facilities to the Majorsville Pipeline allowing for fractionation at the Houston Complex. By the end of 2012, MarkWest Liberty Midstream will have approximately 100 miles of NGL transportation pipeline.

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Fractionation and Market Outlets

- Existing fractionation facility at our Houston Complex with a design capacity of 60,000 Bbl/d that was placed into service in the third quarter of 2011. Prior to the completion of the Houston fractionation facility, only propane was recovered at our Houston Complex and further fractionation of the remaining portion of the NGL stream produced at the Liberty processing plants was performed at the Siloam NGL fractionation plant in our Northeast segment.
- Existing interconnect with a key interstate pipeline providing a market outlet for the propane produced from this region.
- Extension of our Majorsville NGL pipeline under construction to receive NGLs produced at a third-party' s Fort Beeler processing plant. This project is expected to be completed in the fourth quarter of 2011 and will allow certain producers to benefit from our integrated NGL fractionation and marketing operations.
- Railcar loading facility under construction at our Houston Complex that is expected to be completed in the first half of 2012.

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

Ethane Recovery and associated Market Outlets

Due to the increase production of natural gas from the liquids-rich area of the Marcellus Shale, natural gas processors must begin to recover a significant amount of ethane from the raw NGL stream to continue to meet the pipeline gas quality specifications for residue gas. We have been developing a solution that will have the capability to recover and fractionate the required ethane, will be scalable to recover and fractionate additional ethane at the option of our producer customers, and will provide access to attractive ethane markets in North America and Europe. The primary components of our ethane recovery solution consist of the following:

- 75,000 Bbl/d de-ethanization facilities under construction at our Houston Complex and Majorsville Complex that are expected to be completed by mid- 2013.

- A joint pipeline project with Sunoco Logistics, L.P. (“Sunoco”) that is currently under construction and will deliver Marcellus ethane to Sarnia, Ontario, Canada markets (“Mariner West”). Mariner West will utilize new and existing pipelines and is anticipated to have an initial capacity to transport up to 50,000 Bbl/d of ethane by mid-2013 with the ability to expand to support higher volumes as needed. Sunoco completed an open season for Mariner West and received binding commitments from shippers that would enable the project to proceed as designed.

- Mariner East, an additional joint project with Sunoco, is a pipeline and marine project under consideration that is intended to deliver Marcellus purity ethane to the Gulf Coast and international markets. Mariner East is anticipated to have initial capacity to transport up to 50,000 Bbl/d of ethane by mid-2013.

- We continue to evaluate additional projects that would support a comprehensive ethane solution for producers in the Marcellus Shale.

Gulf Coast

- *Javelina.* We own and operate the Javelina processing facility, a natural gas processing facility in Corpus Christi, Texas that treats and processes off-gas from six local refineries operated by three different refinery customers. We also have a product supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for all of the product processed by the SMR that is operated by a third party. The product received under this agreement is sold to a refinery customer pursuant to a corresponding long-term agreement.

The following summarizes the percentage of our segment revenue and net operating margin (a non-GAAP financial measure, see above) generated by our assets, by segment, for the nine months ended September 30, 2011:

	Southwest	Northeast	Liberty	Gulf Coast
Segment revenue	61%	18%	15%	6%
Net operating margin	49%	21%	18%	12%

Segment Operating Results

Items below *Income from operations* in our Condensed Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any gains (losses) from derivative instruments are not allocated to individual business segments. Management does not consider these items allocable to or controllable by any individual business segment and therefore excludes these items when evaluating segment performance. The segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests. The tables below present financial information, as evaluated by management, for the reported segments for the three months ended September 30, 2011 and 2010 and for the nine months ended September 30, 2011 and 2010. The information includes net operating margin, a non-GAAP financial measure. See above for a reconciliation of net operating margin to *Income from operations*, the most comparable GAAP financial measure.

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Three months ended September 30, 2011 compared to three months ended September 30, 2010

Southwest

	Three months ended September 30, 2011	2010	$ Change	% Change
		(in thousands)		
Segment revenue	$ 241,998	$ 159,044	$ 82,954	52%
Purchased product costs	141,067	74,835	66,232	89%
Net operating margin	100,931	84,209	16,722	20%
Facility expenses	21,043	20,659	384	2%
Portion of operating income attributable to non-controlling interests	1,227	1,906	(679)	(36)%
Operating income before items not allocated to segments	$ 78,661	$ 61,644	$ 17,017	28%

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

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

Northeast

	Three months ended September 30, 2011	2010	$ Change	% Change
		(in thousands)		
Segment revenue	$ 55,920	$ 83,400	$ (27,480)	(33)%
Purchased product costs	15,947	55,879	(39,932)	(71)%
Net operating margin	39,973	27,521	12,452	45%
Facility expenses	6,879	5,268	1,611	31%
Operating income before items not allocated to segments	$ 33,094	$ 22,253	$ 10,841	49%

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

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

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

Liberty

	Three months ended September 30, 2011	2010	$ Change	% Change
		(in thousands)		

Segment revenue	$ 78,586	$ 28,606	$ 49,980	175%
Purchased product costs	32,270	5,986	26,284	439%
Net operating margin	46,316	22,620	23,696	105%
Facility expenses	9,108	5,668	3,440	61%
Portion of operating income attributable to non-controlling interests	18,223	6,772	11,451	169%
Operating income before items not allocated to segments	$ 18,985	$ 10,180	$ 8,805	86%

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Segment Revenue. Revenue increased due to ongoing expansion of the Liberty operations and higher NGL prices. Revenue increased approximately $13.4 million related to gathering and processing fees and approximately $34.4 million related to NGL product sales.

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

Facility Expenses. Facility expenses increased due to the ongoing expansion of the Liberty operations.

Portion of Operating Income Attributable to Non-controlling Interests. Portion of operating income attributable to non-controlling interests represents M&R' s interest in net operating income of MarkWest Liberty Midstream. The increase is the result of ongoing expansion of the Liberty operations, as well as M&R' s interest increasing from 40% to 49% effective January 1, 2011.

Gulf Coast

	Three months ended September 30,			
	2011	2010	$ Change	% Change
		(in thousands)		
Segment revenue	$ 26,868	$ 21,320	$ 5,548	26%
Purchased product costs	–	–	–	N/A
Net operating margin	26,868	21,320	5,548	26%
Facility expenses	9,798	8,785	1,013	12%
Operating income before items not allocated to segments	$ 17,070	$ 12,535	$ 4,535	36%

Segment Revenue. Revenue increased primarily due to higher pricing on NGL products.

Facility Expenses. Facility expenses increased primarily due to the timing of facility maintenance and repairs.

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

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated income (loss) before provision for income tax for the three months ended September 30, 2011 and 2010. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

	Three months ended September 30, 2011	Three months ended September 30, 2010	$ Change	% Change
	(in thousands)			
Total segment revenue	$ 403,372	$ 292,370	$ 111,002	38%
Derivative gain (loss) not allocated to segments	106,943	(36,959)	143,902	(389)%
Revenue deferral adjustment	(2,489)	–	(2,489)	N/A
Total revenue	$ 507,826	$ 255,411	$ 252,415	99%
Operating income before items not allocated to segments	$ 147,810	$ 106,612	$ 41,198	39%
Portion of operating income attributable to non-controlling interests	19,450	8,678	10,772	124%
Derivative gain (loss) not allocated to segments	111,004	(56,391)	167,395	(297)%
Revenue deferral adjustment	(2,489)	–	(2,489)	N/A
Compensation expense included in facility expenses not allocated to segments	(263)	(404)	141	(35)%
Facility expenses adjustments	2,855	2,850	5	0%
Selling, general and administrative expenses	(20,162)	(17,137)	(3,025)	18%
Depreciation	(38,715)	(31,362)	(7,353)	23%
Amortization of intangible assets	(10,985)	(10,193)	(792)	8%
Loss on disposal of property, plant and equipment	(147)	(1,937)	1,790	(92)%
Accretion of asset retirement obligations	(557)	(70)	(487)	696%
Income from operations	207,801	646	207,155	32,067%
Loss from unconsolidated affiliate	(507)	–	(507)	N/A
Interest income	62	422	(360)	(85)%
Interest expense	(26,899)	(26,433)	(466)	2%
Amortization of deferred financing costs and discount (a component of interest expense)	(1,002)	(3,625)	2,623	(72)%
Loss on redemption of debt	(133)	–		N/A
Miscellaneous (expense) income, net	(4)	76	(80)	(105)%
Income (loss) before provision for income tax	$ 179,318	$ (28,914)	$ 208,232	(720)%

Derivative Gain (Loss) Not Allocated to Segments. Unrealized gain from the mark-to-market of our derivative instruments was $126.8 million for the three months ended September 30, 2011 compared to an unrealized loss of $50.7 million for the same period in 2010. Realized loss from the settlement of our derivative instruments was $15.8 million for the three months ended September 30, 2011 compared to $5.7 million for the same period in 2010. The total change of $167.4 million is due mainly to volatility in commodity prices.

Revenue Deferral Adjustment. Revenue deferral adjustment relates primarily to certain contracts in which the cash consideration we receive for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as we will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the three months ended September 30, 2011, approximately $0.2 million and $2.3 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Based on current commodity prices, management expects the deferred revenue in subsequent periods to approximate the current quarter' s amount until the beginning of 2015 when the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

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

Depreciation. Depreciation increased due to additional projects completed during 2010 through the third quarter of 2011, as well as the Langley Acquisition.

Amortization of Deferred Financing Costs and Discount. Amortization of deferred financing costs and discount decreased primarily due to the write off of the unamortized discount associated with our 6.875% senior unsecured notes due 2014 (the "2014 Senior Notes"), which were redeemed in the fourth quarter of 2010.

Nine months ended September 30, 2011 compared to nine months ended September 30, 2010

Southwest

	Nine months ended September 30,			
	2011	**2010**	**$ Change**	**% Change**
		(in thousands)		
Segment revenue	$ 679,347	$ 479,051	$ 200,296	42%
Purchased product costs	373,251	220,849	152,402	69%
Net operating margin	306,096	258,202	47,894	19%
Facility expenses	62,055	60,543	1,512	2%
Portion of operating income attributable to non-controlling interests	3,745	4,962	(1,217)	(25)%
Operating income before items not allocated to segments	$ 240,296	$ 192,697	$ 47,599	25%

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

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

Northeast

	Nine months ended September 30,			
	2011	**2010**	**$ Change**	**% Change**
		(in thousands)		

Segment revenue	$ 201,687	$ 276,570	$ (74,883)	(27)%
Purchased product costs	72,527	179,700	(107,173)	(60)%
Net operating margin	129,160	96,870	32,290	33%
Facility expenses	19,402	14,555	4,847	33%
Operating income before items not allocated to segments	$ 109,758	$ 82,315	$ 27,443	33%

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

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

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

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Liberty

	Nine months ended September 30, 2011	2010	$ Change	% Change
		(in thousands)		
Segment revenue	$ 168,142	$ 66,354	$ 101,788	153%
Purchased product costs	51,715	8,570	43,145	503%
Net operating margin	116,427	57,784	58,643	101%
Facility expenses	22,875	19,121	3,754	20%
Portion of operating income attributable to non-controlling interests	45,782	15,617	30,165	193%
Operating income before items not allocated to segments	$ 47,770	$ 23,046	$ 24,724	107%

Segment Revenue. Revenue increased due to ongoing expansion of the Liberty operations and higher NGL prices. Revenue increased approximately $36.3 million related to gathering and processing fees and approximately $60.9 million related to NGL product sales.

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

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

Portion of Operating Income Attributable to Non-controlling Interests. Portion of operating income attributable to non-controlling interests represents M&R' s interest in net operating income of MarkWest Liberty Midstream. The increase is the result of ongoing expansion of the Liberty operations, as well as M&R' s interest increasing from 40% to 49% effective January 1, 2011.

Gulf Coast

	Nine months ended September 30, 2011	2010	$ Change	% Change
		(in thousands)		
Segment revenue	$ 73,310	$ 62,958	$ 10,352	16%
Purchased product costs	–	–	–	N/A
Net operating margin	73,310	62,958	10,352	16%
Facility expenses	27,100	23,875	3,225	14%
Operating income before items not allocated to segments	$ 46,210	$ 39,083	$ 7,127	18%

Segment Revenue. Revenue increased primarily due to increases in commodity prices and the revenues earned from the SMR which did not begin until March 2010. The increases were partially offset by a decrease in volumes due to increased maintenance activities.

Facility Expenses. Facility expenses increased primarily due to operating expenses of the SMR which began in March 2010.

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Reconciliation of Segment Operating Income to Consolidated Income Before Provision for Income Tax

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated income before provision for income tax for the nine months ended September 30, 2011 and 2010. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

	Nine months ended September 30, 2011	2010	$ Change	% Change
		(in thousands)		
Total segment revenue	$ 1,122,486	$ 884,933	$ 237,553	27%
Derivative gain not allocated to segments	61,854	2,707	59,147	2,185%
Revenue deferral adjustment	(12,854)	–	(12,854)	N/A
Total revenue	$ 1,171,486	$ 887,640	$ 283,846	32%
Operating income before items not allocated to segments	$ 444,034	$ 337,141	$ 106,893	32%
Portion of operating income attributable to non-controlling interests	49,527	20,579	28,948	141%
Derivative gain (loss) not allocated to segments	46,859	(21,850)	68,709	(314)%
Revenue deferral adjustment	(12,854)	–	(12,854)	N/A

Compensation expense included in facility expenses not allocated to segments	(1,491)	(1,412)	(79)	6%
Facility expenses adjustments	8,565	6,240	2,325	37%
Selling, general and administrative expenses	(60,454)	(55,064)	(5,390)	10%
Depreciation	(110,280)	(89,367)	(20,913)	23%
Amortization of intangible assets	(32,632)	(30,579)	(2,053)	7%
Loss on disposal of property, plant and equipment	(4,619)	(2,116)	(2,503)	118%
Accretion of asset retirement obligations	(934)	(282)	(652)	231%
Income from operations	325,721	163,290	162,431	99%
(Loss) earnings from unconsolidated affiliate	(1,262)	1,517	(2,779)	(183)%
Interest income	214	1,185	(971)	(82)%
Interest expense	(83,036)	(75,970)	(7,066)	9%
Amortization of deferred financing costs and discount (a component of interest expense)	(3,873)	(8,517)	4,644	(55)%
Derivative gain related to interest expense	–	1,871	(1,871)	(100)%
Loss on redemption of debt	(43,461)	–	(43,461)	N/A
Miscellaneous income, net	127	1,129	(1,002)	(89)%
Income before provision for income tax	$ 194,430	$ 84,505	$ 109,925	130%

Derivative Gain (Loss) Not Allocated to Segments. Unrealized gain from the mark-to-market of our derivative instruments was $102.7 million for the nine months ended September 30, 2011 compared to $13.8 million for the same period in 2010. Realized loss from the settlement of our derivative instruments was $55.8 million for the nine months ended September 30, 2011 compared to $35.7 million for the same period in 2010. The total change of $68.7 million is due mainly to volatility in commodity prices.

Revenue Deferral Adjustment. Revenue deferral adjustment relates primarily to certain contracts in which the cash consideration we receive for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as we will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the nine months ended September 30, 2011, approximately $6.9 million and $5.9 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

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

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

Depreciation. Depreciation increased due to additional projects completed during 2010 through the third quarter of 2011, as well as the Langley Acquisition.

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

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

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

Loss on Redemption of Debt. Loss on redemption of debt relates to the redemption of $275.0 million of our 2016 Senior Notes and $165.6 million of our 2018 Senior Notes occurring primarily in the first quarter of 2011. Approximately $3.8 million relates to the non-cash write off of the unamortized discount and deferred finance costs and approximately $39.6 million relates to the payment of the related tender premiums and third-party expenses. See Note 9 of the accompanying Notes to the Condensed Consolidated Financial Statements.

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Operating Data

	Three months ended September 30,		%	Nine months ended September 30,		
	2011	2010	Change	2011	2010	% Change
Southwest						
East Texas gathering systems throughput (Mcf/d)	417,400	433,000	(4)%	423,800	433,600	(2)%
East Texas natural gas processed (Mcf/d)	229,700	221,900	4%	226,000	236,900	(5)%
East Texas NGL sales (gallons, in thousands)	59,000	60,200	(2)%	175,200	186,300	(6)%
Western Oklahoma gathering system throughput (Mcf/d) (1)	241,300	183,600	31%	224,400	189,300	19%
Western Oklahoma natural gas processed (Mcf/d)	153,200	143,300	7%	156,600	129,600	21%
Western Oklahoma NGL sales (gallons, in thousands)	37,000	33,800	9%	111,100	93,400	19%
Southeast Oklahoma gathering system throughput (Mcf/d)	512,600	535,800	(4)%	507,500	524,100	(3)%
Southeast Oklahoma natural gas processed (Mcf/d) (2)	105,400	94,500	12%	103,100	79,000	31%
Southeast Oklahoma NGL sales (gallons, in thousands)	30,600	29,900	2%	92,100	72,300	27%
Arkoma Connector Pipeline throughput (Mcf/d)	298,600	396,800	(25)%	294,300	378,900	(22)%

Other Southwest gathering system throughput (Mcf/d) (3)	29,900	37,000	(19)%	31,500	40,200	(22)%
Northeast (4)						
Natural gas processed (Mcf/d)	277,400	190,300	46%	300,700	194,400	55%
NGLs fractionated (Bbl/d) (5)	19,300	21,200	(9)%	21,400	20,500	4%
Keep-whole sales (gallons, in thousands)	21,700	28,700	(24)%	82,600	105,300	(22)%
Percent-of-proceeds sales (gallons, in thousands)	31,600	30,800	3%	95,600	87,900	9%
Total NGL sales (gallons, in thousands) (6)	53,300	59,500	(10)%	178,200	193,200	(8)%
Crude oil transported for a fee (Bbl/d)	9,900	12,100	(18)%	10,500	12,400	(15)%
Liberty						
Natural gas processed (Mcf/d)	366,200	156,300	134%	306,700	122,300	151%
Gathering system throughput (Mcf/d)	258,300	153,300	68%	228,900	127,700	79%
NGLs fractionated (Bbl/d) (7)	12,400	4,200	195%	9,300	3,500	166%
NGL sales (gallons, in thousands) (8)	61,100	32,400	89%	163,500	77,400	111%
Gulf Coast						
Refinery off-gas processed (Mcf/d)	122,000	123,000	(1)%	113,200	118,400	(4)%
Liquids fractionated (Bbl/d)	23,100	23,100	0%	21,400	22,800	(6)%
NGL sales (gallons excluding hydrogen, in thousands)	89,200	89,300	(0)%	245,500	261,700	(6)%

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

(2) The natural gas processing in Southeast Oklahoma is outsourced to Centrahoma, our equity investment, or a third-party processor.

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

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

(5) Amount includes 4,400 barrels per day and 4,300 barrels per day fractionated on behalf of Liberty for the three months ended September 30, 2011 and 2010, respectively, and includes 5,100 barrels per day and 3,500 barrels per day fractionated on behalf of Liberty for the nine months ended September 30, 2011 and 2010, respectively. Beginning in the fourth quarter of 2011, Siloam will no longer fractionate NGLs on behalf of Liberty due to the operation of Liberty' s fractionation facility that began in September 2011.

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(6) Represents sales at the Siloam fractionator. The total sales exclude approximately 17,100,000 gallons and 16,700,000 gallons sold by the Northeast on behalf of Liberty for the three months ended September 30, 2011 and 2010, respectively, and

approximately 58,600,000 gallons and 40,000,000 gallons sold for the nine months ended September 30, 2011 and 2010, respectively. These volumes are included as part of NGLs sold at Liberty.

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

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

Liquidity and Capital Resources

Our primary strategy is to expand our asset base through organic growth projects and selective third-party acquisitions that are accretive to our cash available for distribution per common unit. In 2010, we spent approximately $458.7 million primarily on organic expansion opportunities, of which approximately $184 million was funded by our MarkWest Liberty Midstream joint venture partner.

Our 2011 capital plan is summarized in the table below (in millions):

	Full Year Plan		Actual
	Low	High	Nine months ended September 30, 2011
Consolidated growth capital	$ 575	$ 620	$ 351
Liberty joint venture partner' s estimated share of growth capital	(130)	(150)	(69)
Partnership share of growth capital	445	470	282
Langley Acquisition	230	230	231
Partnership share of growth capital and acquisitions	$ 675	$ 700	$ 513
Consolidated maintenance capital	$ 15	$ 15	$ 9

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

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, contributions from our MarkWest Liberty Midstream joint venture partner, our Credit Facility and access to debt and equity markets, both public and private. 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.

In July 2011, we reached Equalization related to the capital contributed to MarkWest Liberty Midstream (see Note 4 in the accompanying condensed consolidated financial statements). As a result, MarkWest Liberty Midstream will be funded by us and our joint venture partner in proportion to our ownership percentages for future capital requirements, which will decrease our proportionate share of the capital funding from 73% during the nine months ended September 30, 2011 to 51%. Based on agreed-to levels of capital contributions that are expected to be reached in 2012, we will have the option to increase our portion of the capital contributions to 55% of each future capital call, which if elected by us, will increase our ownership percentage in MarkWest Liberty Midstream.

Management believes that expenditures for our currently planned capital projects will be funded with cash flows from operations, current cash balances, contributions by our joint venture partner for capital projects encompassed by the Liberty joint venture, our current borrowing capacity under the Credit Facility, additional long-term borrowings, and proceeds from equity offerings. Our access to capital markets can be impacted by factors outside our control, including economic conditions; however, we believe that our strong cash flows and balance sheet, our Credit Facility and our credit rating will provide us with adequate access to funding given our expected cash needs. Any new borrowing cost would be affected by market conditions and long-term debt ratings

assigned by independent rating agencies. As of October 28, 2011, our credit ratings were Ba2 with a Stable outlook by Moody' s Investors Service, BB with a Stable outlook by Standard & Poor' s, which both reflect upgrades during 2011, and BB with a Stable outlook by Fitch Ratings. Changes in our operating results, cash flows or financial position could impact the ratings assigned by the various rating agencies. Should our credit ratings be adjusted downward, we may incur higher costs to borrow, which could have a material impact on our financial condition and results of operations.

Debt Financing Activities

On June 15, 2011, we executed a joinder agreement to include an additional member in the bank group and to exercise a portion of the accordion feature under the Credit Facility, thereby increasing the borrowing capacity of the Credit Facility to $745 million and reducing the accordion feature to $155 million of uncommitted funds. On September 7, 2011, we amended the Credit Facility, increasing the borrowing capacity of the Credit Facility to $750 million, increasing the uncommitted accordion feature to $250 million, reducing the interest rate ranges by 75 basis points, and extending the maturity date to September 2016. Under the provisions of the Credit Facility we are subject to a number of restrictions and covenants. As of September 30, 2011, we were in compliance with all of our debt covenants and we expect to remain in compliance for at least the next twelve months. These covenants are used to calculate the available borrowing capacity on a quarterly basis. As of October 28, 2011, we had no borrowings outstanding and $27.3 million of letters of credit outstanding under the Credit Facility, leaving approximately $722.7 million available for borrowing.

On February 24, 2011, we completed a public offering of $300 million in aggregate principal amount of 2021 Senior Notes, which were issued at par. On March 10, 2011, we completed a follow-on public offering of an additional $200 million in aggregate principal amount of 2021 Senior Notes, which were issued at 99.5% of par and are treated as a single class of debt securities with the 2021 Senior Notes issued on February 24, 2011. The 2021 Senior Notes mature on August 15, 2021, and interest is payable semi-annually in arrears on February 15 and August 15, commencing August 15, 2011. We received aggregate net proceeds of approximately $492 million from the 2021 Senior Notes offerings after deducting the underwriting fees and other third-party expenses and used the net proceeds to fund the repurchase of approximately $272.2 million in aggregate principal amount of 2016 Senior Notes and approximately $165.6 million in aggregate principal amount of 2018 Senior Notes. The remaining proceeds were used to repay borrowings under the Credit Facility. On July 15, 2011, we repurchased the remaining 2016 Senior Notes. As a result of these refinancing activities, we have significantly reduced the interest rates and extended the terms of our long-term financing.

On October 25, 2011, we commenced a public offering of $700 million in aggregate principal amount of 6.25% senior unsecured notes due June 2022 ("2022 Senior Notes"). The offering is expected to close on November 3, 2011. Interest on the 2022 Notes is payable semi-annually in arrears on June 15 and December 15, commencing June 15, 2012. We intend to use the net proceeds from this offering to fund the repurchase of any and all of the $334.4 million outstanding 2018 Senior Notes that are tendered pursuant to a concurrent tender offer and any remaining net proceeds will be used to provide additional working capital for general partnership purposes. We have offered to repurchase the 2018 Senior Notes at 112.5% of their principal amounts for all notes tendered prior to November 9, 2011. Any 2018 Senior Notes tendered after November 9, 2011 but prior to November 25, 2011 would be repurchased at 109.5% of their principal amounts. Assuming that all of the 2018 Senior Notes are tendered by November 9, 2011, we would record a pre-tax loss on redemption of debt of approximately $47 million, which would consist of $42 million for the payment of the related tender premiums and third-party expenses and $5 million for the non-cash write off of the unamortized discount and deferred finance costs.

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

The Credit Facility also limits our ability to enter into transactions with parties that require margin calls under certain derivative instruments. The Credit Facility prevents members of the participating bank group from requiring margin calls. As of October 28, 2011, all of our derivative positions are with members of the participating bank group and are not subject to margin deposit requirements. We believe this arrangement gives us additional liquidity as it allows us to enter into derivative instruments without utilizing cash for margin calls or requiring the use of letters of credit.

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Equity Offerings

On January 14, 2011, we completed a public offering of approximately 3.45 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriter' s over-allotment option. Net proceeds of approximately $138 million were used to partially fund our ongoing capital expenditure program, including a portion of the costs associated with the Langley Acquisition.

On July 13, 2011, we completed a public offering of approximately 4.0 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds of approximately $185 million and were used to repay borrowings under the Credit Facility and to partially fund our ongoing capital expenditure program.

On October 13, 2011, we completed a public offering of approximately 5.75 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds of approximately $251 million were used to repay borrowings under the Credit Facility and to provide working capital for general partnership purposes.

Cash Flow

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

	Nine months ended September 30,		
	2011	**2010**	**Change**
Net cash provided by operating activities	$ 331,249	$ 197,238	$ 134,011
Net cash used in investing activities	(587,686)	(373,649)	(214,037)
Net cash provided by financing activities	348,164	177,154	171,010

Net cash provided by operating activities increased primarily due to a $106.9 million increase in operating income, excluding derivative gains and losses, in our operating segments, which was partially offset by a $20.1 million increase in net cash payments related to the settlement of commodity derivative positions. The increase in operating income was also due to increases in operating cash flow resulting from changes in working capital.

Net cash used in investing activities increased primarily due to the $230.7 million Langley Acquisition.

Net cash provided by financing activities increased primarily due to:

- $181.2 million increase in proceeds from public offerings, and
- $161.0 million increase in net borrowings.

These increases were partially offset by:

- $67.7 million decrease in cash contributions received from our joint venture partner,
- $44.3 million increase in distributions to non-controlling interest holders due to the increased cash flow from MarkWest Liberty Midstream, and
- $39.6 million increase in premiums paid for the redemption of our 2016 and 2018 Senior Notes,
- $21.0 million increase in distributions to common unitholders due to additional units outstanding and the growth in the per unit distribution,
- $3.4 million decrease in payments for debt issuance costs, deferred financing costs and registration costs.

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Contractual Obligations

We periodically make other commitments and become subject to other contractual obligations that we believe to be routine in nature and incidental to the operation of the business. Management believes that such routine commitments and contractual obligations do not have a material impact on our business, financial condition or results of operations. As of September 30, 2011, our purchase obligations for the remainder of 2011 were $119.1 million compared to our 2011 obligations of $56.0 million as of December 31, 2010. The increase is due primarily to obligations related to the ongoing expansion in our Liberty and Northeast segments. Purchase obligations represent purchase orders and contracts related to property, plant and equipment.

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Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates are used in accounting for, among other items, valuing identified intangible assets; evaluating impairments of long-lived assets, goodwill and equity investments; share-based compensation; risk management activities and derivative financial instruments; and VIEs.

There have not been any material changes during the nine months ended September 30, 2011 to the methodology applied by management for critical accounting policies previously disclosed in Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations–Critical Accounting Policies* in our Annual Report on Form 10-K for the year ended December 31, 2010, except as noted below.

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

Recent Accounting Pronouncements

Refer to Note 2 of the accompanying Notes to the Condensed Consolidated Financial Statements for information regarding recent accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk

The information about commodity price risk for the nine months ended September 30, 2011 does not differ materially from that discussed in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* of our Annual Report on Form 10-K for the year ended December 31, 2010.

Outstanding Derivative Contracts

The following table provides information on the volume of our derivative activity for positions related to long liquids and keep-whole price risk at September 30, 2011, including the weighted average prices ("WAVG"):

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)	Fair Value (in thousands)
2011	1,592	$ 67.25	$ 85.40	$ (129)
2012	2,634	75.65	97.22	3,614
2013	3,714	88.08	107.45	13,773
2014	734	95.36	114.81	3,811

WTI Crude Puts	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	Fair Value (in thousands)
2011	1,812	$ 80.00	$ 876

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2011 (1)	868	$ 89.25	$ (4,981)
2012	3,983	85.27	(945)
2013	2,474	90.68	6,142
2014	601	101.50	3,263

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2011	8,310	$ 4.21	$ (399)
2012	4,650	5.62	(2,562)
2013	980	5.13	(181)

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	125,179	$ 1.47	$ (153)
2012 (Jan-Mar)	140,047	1.42	(62)

IsoButane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	23,380	$ 1.88	$ (224)
2012 (Jan-Mar)	25,051	1.85	(12)

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	35,108	$ 1.82	$ 135
2012 (Jan-Mar)	40,083	1.79	241

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	89,723	$ 2.28	$ 1,037
2012 (Jan-Mar)	92,847	2.29	1,350

(1) During the second quarter of 2011 we effectively converted our swap hedges related to our remaining 2011 NGL exposure from crude proxy hedges to direct refined product hedges by purchasing crude swaps to offset the existing crude swap positions. The volume of offsetting crude swaps outstanding as of September 30, 2011 was 352,835 barrels. The outstanding positions were being used to hedge refined products. To continue the hedge of the refined products we sold refined product swaps through the remainder of 2011.

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The following tables provide information on the volume of our taxable subsidiary' s commodity derivative activity for positions related to keep-whole price risk at September 30, 2011, including the WAVG:

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)	Fair Value (in thousands)
2012	1,122	$ 78.49	$ 101.71	$ 2,381

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2011 (1)	–	N/A	$ (3,765)
2012	1,083	$ 87.11	(1,489)
2013	1,304	94.32	4,859

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2011	17,728	$ 8.28	$ (7,260)
2012	14,419	6.02	(9,104)
2013	9,793	5.34	(1,918)
2014	4,249	5.69	(856)

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	205,971	$ 1.48	$ (377)
2012 (Jan-Mar)	152,569	1.46	(196)
2013 (Jan-Mar, Oct-Dec)	36,885	1.29	384
2014 (Jan-Mar, Oct-Dec)	87,837	1.25	418

IsoButane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	13,800	$ 1.71	$ (386)
2012 (Jan-Mar)	8,282	1.82	(49)
2013	3,081	1.70	87
2014	3,885	1.67	71

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	37,852	$ 1.73	$ (325)
2012 (Jan-Mar)	22,944	1.75	(51)
2013	8,512	1.61	230
2014	10,711	1.61	275

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2011	25,037	$ 2.31	$ 298
2012 (Jan-Mar)	14,969	2.28	166
2013	5,600	2.26	549
2014	7,106	2.32	805

(1) During the second quarter of 2011 we effectively converted our swap hedges related to our remaining 2011 and first quarter 2012 NGL exposure from crude proxy hedges to direct refined product hedges by purchasing crude swaps to offset the existing crude swap positions. The volume of offsetting crude swaps outstanding as of September 30, 2011 was 403,502 barrels for 2011 and 277,000 barrels for Q1 2012. The outstanding positions were being used to hedge refined products. To continue the hedge of the refined products we sold refined product swaps through the remainder 2011 and the first quarter of 2012.

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The following tables provide information on the volume of MarkWest Liberty Midstream' s commodity derivative activity for positions related to long liquids price risk at September 30, 2011, including the WAVG:

Propane Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2011	10,948	$ 1.56	$ 55
2012 (Jan-Mar)	43,353	1.56	225

The following table provides information on the derivative positions related to long liquids and keep-whole price risk that we have entered into subsequent to September 30, 2011, including the WAVG:

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)
2011 (Dec)	676	$ 91.20
2012	2,000	88.11

Nat Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMbtu)
2011 (Dec)	3,063	$ 3.72
2012	6,871	3.90

Ethane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)

2011 (Nov-Dec)	85,139	$	0.87

The following table provides information on the derivative positions related to long liquids and keep-whole price risk that MarkWest Liberty Midstream entered into subsequent to September 30, 2011, including the WAVG:

Propane Swaps	Volumes (Gal/d)		WAVG Price (Per Gal)
2011 (Dec)	7,580	$	1.43
2012 (Feb)	17,750		1.41

Embedded Derivatives in Commodity Contracts

We have a commodity contract with a producer in the Appalachia region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. This contract is accounted for as an embedded derivative and is recorded at fair value. The changes in fair value of this commodity contract are based on the difference between the contractual and index pricing and are recorded in earnings through *Derivative (gain) loss related to purchased product costs*. In February 2011, we executed agreements with the producer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022. As of September 30, 2011, the estimated fair value of this contract was a liability of $94.7 million and the recorded value was a liability of $41.1 million. The recorded liability does not include the inception fair value of the commodity contract related to the extended period from April 1, 2015 to December 31, 2022. In accordance with GAAP for non-option embedded derivatives, the fair value of this extended portion of the commodity contract at its inception of February 1, 2011 is deemed to be allocable to the host processing contract and therefore not recorded as a derivative liability. See the following table for a reconciliation of the liability recorded for the embedded derivative as of September 30, 2011 (in thousands).

Fair value of commodity contract	$	94,652
Inception value for period from April 1, 2015 to December 31, 2022		(53,507)
Derivative liability as of September 30, 2011	$	41,145

We have a commodity contract that gives us an option to fix a component of the utilities cost to an index price on electricity at one of our plant locations through the fourth quarter of 2014. The value of the derivative component of this contract is marked to market through *Derivative gain related to facility expenses*. As of September 30, 2011, the estimated fair value of this contract was an asset of $3.9 million.

Interest Rate Risk

The information about interest rate risk for the nine months ended September 30, 2011 does not differ materially from that discussed in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* of our Annual Report on Form 10-K for the year ended December 31, 2010.

Credit Risk

The information about credit risk for the nine months ended September 30, 2011 does not differ materially from that discussed in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* of our Annual Report on Form 10-K for the year ended December 31, 2010.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of the Partnership' s management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rule 13a-15(e) of the 1934 Act, as of September 30, 2011. Based on this evaluation, the Partnership' s management, including our Chief Executive Officer and Chief Financial Officer, concluded that as of September 30, 2011, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC' s rules and forms and to provide reasonable assurance that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

Limitations on Controls

Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives as specified above. Management does not expect, however, that our disclosure controls and procedures will prevent or detect all error and fraud. Any control system, no matter how well designed and operated, is based upon certain assumptions and can provide only reasonable, not absolute, assurance that its objectives will be met. Further, no evaluation of controls can provide absolute assurance that misstatements due to error or fraud will not occur or that all control issues and instances of fraud, if any, within the Partnership have been detected.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2011 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II–OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Note 11 of the accompanying Notes to the Condensed Consolidated Financial Statements for information regarding legal proceedings.

Item 1A. Risk Factors

There were no material changes to our risk factors as disclosed in Item1A. *Risk Factors* in our Annual Report on Form 10-K for the year ended December 31, 2010, except as set forth below.

New federal pipeline safety regulations relating to liquid pipelines could increase our cost of operations.

On May 5, 2011, the Pipeline and Hazardous Materials Safety Administration issued a final rule to extend safety regulations to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner. These regulations impose additional reporting obligations as well as integrity management requirements. While we do not believe that compliance with these new regulations will have a material adverse effect on our operations, we are in the process of evaluating the application and impact of the new regulations on our facilities. It is possible that compliance with these new requirements may increase our operating costs and reduce our cash flows available for distribution to our common unitholders.

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Item 6. Exhibits

4.1*	Fifth Supplemental Indenture dated as of October 21, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.2*	Fourth Supplemental Indenture dated as of October 21, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
10.1(1)	First Amendment to Amended and Restated Credit Agreement dated as of September 7, 2011 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, the other agents and lenders party thereto, and Wells Fargo Securities, LLC and RBC Capital Markets, as joint lead arrangers and joint bookrunners.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of the Chief Executive Officer 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 the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following financial information from the quarterly report on Form 10-Q of MarkWest Energy Partners, L.P. for the quarter ended September 30, 2011, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets, (ii) Condensed Consolidated Statements of Operations, (iii) Condensed Consolidated Statements of Changes in Equity, (iv) Condensed Consolidated Statements of Cash Flows, and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

(1)   Incorporated by reference to the Current Report on Form 8-K filed September 13, 2011.

*   Filed herewith

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SIGNATURES

Pursuant to the requirements 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: November 7, 2011

/s/ FRANK M. SEMPLE

Frank M. Semple
Chairman, President & Chief Executive Officer
(Principal Executive Officer)

Date: November 7, 2011

/s/ NANCY K. BUESE

Nancy K. Buese
Senior Vice President & Chief Financial Officer
(Principal Financial Officer)

Date: November 7, 2011

/s/ PAULA L. ROSSON

Paula L. Rosson
Vice President & Chief Accounting Officer
(Principal Accounting Officer)

Exhibit 4.1

MARKWEST ENERGY PARTNERS, L.P.,

MARKWEST ENERGY FINANCE CORPORATION, as Issuers,

and

the Subsidiary Guarantors named herein

8¾% SENIOR NOTES DUE 2018

FIFTH SUPPLEMENTAL INDENTURE

DATED AS OF OCTOBER 21, 2011

WELLS FARGO BANK, NATIONAL ASSOCIATION,

Trustee

This FIFTH SUPPLEMENTAL INDENTURE (this "Supplemental Indenture"), dated as of October 21, 2011, is among MarkWest Energy Partners, L.P., a Delaware limited partnership (the "Partnership"), MarkWest Energy Finance Corporation, a Delaware corporation ("MarkWest Finance" and, together with the Partnership, the "Issuers"), each of the other parties identified on the signature page hereto (the "Subsidiary Guarantors") and Wells Fargo Bank, National Association, a national banking association, as Trustee.

RECITALS

WHEREAS, the Issuers, the initial Subsidiary Guarantors and the Trustee entered into an Indenture, dated as of April 15, 2008 (as amended and supplemented by four supplemental indentures thereto, the "Indenture"), pursuant to which the Issuers have issued $500,000,000 in principal amount of 8¾% Senior Notes due 2018 (the "Notes");

WHEREAS, Section 9.01(d) of the Indenture provides that the Issuers, the Subsidiary Guarantors and the Trustee may amend or supplement the Indenture in order to add Subsidiary Guarantors pursuant to Section 4.13 or 5.01(c) thereof, without the consent of the Holders of the Notes; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the Certificate of Incorporation and the Bylaws (or comparable constituent documents) of the Issuers, of the Subsidiary Guarantors and of the Trustee necessary to make this Supplemental

Indenture a valid instrument legally binding on the Issuers, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Issuers, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Issuers, the Subsidiary Guarantors and the Trustee.

ARTICLE 2

From this date, in accordance with Section 4.13 or 5.01(c) of the Indenture and by executing this Supplemental Indenture, the Guarantors whose signatures appear below are subject to the provisions of the Indenture to the extent provided for in Article 10 thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Supplemental Indenture. This Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto. Without limiting the generality of the foregoing, the Trustee shall not be responsible in any manner whatsoever for or with respect to any of the recitals or statements contained herein, all of which recitals or statements are made solely by the Issuers and the Subsidiary Guarantors, and the Trustee makes no representation with respect to any such matters. Additionally, the Trustee makes no representations as to the validity or sufficiency of this Supplemental Indenture.

Section 3.03. THIS SUPPLEMENTAL INDENTURE SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

Section 3.04. The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed, all as of the date first written above.

MARKWEST ENERGY FINANCE CORPORATION

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST ENERGY PARTNERS, L.P.

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST HYDROCARBON, INC.

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST ENERGY GP, L.L.C.

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MASON PIPELINE LIMITED LIABILITY COMPANY

By: MarkWest Hydrocarbon, Inc.,
its Sole Member

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and ChiefFinancial Officer

MARKWEST ENERGY OPERATING COMPANY, L.L.C.

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fifth Supplemental Indenture

MARKWEST BLACKHAWK, L.L.C.
MARKWEST ENERGY APPALACHIA, L.L.C.
MARKWEST ENERGY EAST TEXAS GAS COMPANY, L.L.C.
MARKWEST GAS MARKETING, L.L.C.
MARKWEST GAS SERVICES, L.L.C.
MARKWEST JAVELINA COMPANY, L.L.C.
MARKWEST JAVELINA PIPELINE COMPANY, L.L.C.
MARKWEST LIBERTY GAS GATHERING, L.L.C.
MARKWEST MARKETING, L.L.C.
MARKWEST MOUNTAINEER PIPELINE COPMANY, L.L.C.
MARKWEST NEW MEXICO, L.L.C.
MARKWEST PINNACLE, L.L.C.
MARKWEST PIPELINE COMPANY, L.L.C.
MARKWEST PNG UTILITY, L.L.C.
MARKWEST POWER TEX, L.L.C.
MARKWEST TEXAS PNG UTILITY, L.L.C.

By: MarkWest Energy Operating Company, L.L.C.,
its Sole Member

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese

Title: Senior Vice President and Chief Financial Officer

Signature Page to Fifth Supplemental Indenture

MARKWEST MICHIGAN PIPELINE COMPANY, L.L.C.
MARKWEST OKLAHOMA GAS COMPANY, L.L.C.

By: MarkWest Energy Operating Company, L.L.C., its Managing Member

By: MarkWest Energy Partners, L.P., its Managing Member

By: MarkWest Energy GP, L.L.C., its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MATREX, L.L.C.

By: West Shore Processing Company L.L.C., its Sole Member and Manager

By: MarkWest Energy Operating Company, L.L.C., its Sole Member and Manager

By: MarkWest Energy Partners, L.P., its Managing Member

By: MarkWest Energy GP, L.L.C., its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fifth Supplemental Indenture

MARKWEST MCALESTER, L.L.C.

By: MarkWest Oklahoma Gas Company, L.L.C.,
its Sole Member

By: MarkWest Energy Operating Company, L.L.C.,
its Managing Member

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST RANGER PIPELINE COMPANY, L.L.C

By: MarkWest Energy Appalachia, L.L.C.,
its Sole Member

By: MarkWest Energy Operating Company, L.L.C.,
its Sole Member

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fifth Supplemental Indenture

WEST SHORE PROCESSING COMPANY L.L.C.

By: MarkWest Energy Operating Company, L.L.C.,
its Sole Member and Manager

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,

its General Partner

By: /s/ Nancy Buese

Name: Nancy Buese

Title: Senior Vice President and Chief Financial Officer

Signature Page to Fifth Supplemental Indenture

WELLS FARGO BANK, NATIONAL ASSOCIATION, AS TRUSTEE

By: /s/ John Stohlmann

Name: John Stohlmann

Title: Vice President

Signature Page to Fifth Supplemental Indenture

Exhibit 4.2

FOURTH SUPPLEMENTAL INDENTURE

This FOURTH SUPPLEMENTAL INDENTURE (this "Supplemental Indenture"), dated as of October 21, 2011, is among MarkWest Energy Partners, L.P., a Delaware limited partnership (the "Partnership"), MarkWest Energy Finance Corporation, a Delaware corporation ("MarkWest Finance" and, together with the Partnership, the "Issuers"), each of the other parties identified on the signature page hereto (the "Subsidiary Guarantors") and Wells Fargo Bank, National Association, a national banking association, as Trustee.

RECITALS

WHEREAS, the Issuers, the initial Subsidiary Guarantors and the Trustee entered into (i) an Indenture, dated as of November 2, 2010 (as amended and supplemented by the first supplemental indenture and the third supplemental indenture thereto, the "2020 Notes Indenture"), pursuant to which the Issuers have issued $500,000,000 in principal amount of 6¾% Senior Notes due 2020 (the "2020 Notes"), and (ii) an Indenture, dated as of November 2, 2010 (as amended and supplemented by the second supplemental indenture and the third supplemental indenture thereto, the "2021 Notes Indenture" and together with the 2020 Notes Indenture, the "Indentures")), pursuant to which the Issuers have issued $500,000,000 in principal amount of 6.5% Senior Notes due 2021 (the "2021 Notes" and together with the 2020 Notes, the "Notes"));

WHEREAS, Section 10.01 of the Indentures provides that the Issuers, the Subsidiary Guarantors and the Trustee may amend or supplement the Indentures in order to add Subsidiary Guarantors pursuant to Section 5.13 or 6.01(c) thereof, without the consent of the Holders of the Notes; and

WHEREAS, all acts and things prescribed by the Indentures, by law and by the Certificate of Incorporation and the Bylaws (or comparable constituent documents) of the Issuers, of the Subsidiary Guarantors and of the Trustee necessary to make this Supplemental Indenture a valid instrument legally binding on the Issuers, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indentures and in consideration of the above premises, the Issuers, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

This Supplemental Indenture is supplemental to the Indentures and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indentures for any and all purposes.

This Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Issuers, the Subsidiary Guarantors and the Trustee.

ARTICLE II

From this date, in accordance with Section 5.13 or 6.01(c) of the Indentures and by executing this Supplemental Indenture, the Guarantors whose signatures appear below are subject to the provisions of the Indentures to the extent provided for in Article XI thereunder.

ARTICLE III

Except as specifically modified herein, the Indentures and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indentures.

The Trustee accepts the amendments of the Indentures effected by this Supplemental Indenture and agrees to execute the trust created by the Indentures as hereby amended, but on the terms and conditions set forth in the Indentures, including the terms and provisions defining and limiting the liabilities and responsibilities of the Trustee, which terms and provisions shall in like manner define and limit its liabilities and responsibilities in the performance of the trust created by the Indentures as hereby amended, and without limiting the generality of the foregoing, the Trustee shall not be responsible in any manner whatsoever for or with respect to any of the recitals or statements contained herein, all of which recitals or statements are made solely by the Issuers and the Subsidiary Guarantors, and the Trustee makes no representation with respect to any such matters. Additionally, the Trustee makes no representations as to the validity or sufficiency of this Supplemental Indenture.

THIS SUPPLEMENTAL INDENTURE SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed, all as of the date first written above.

MARKWEST ENERGY FINANCE CORPORATION

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST ENERGY PARTNERS, L.P.

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST HYDROCARBON, INC.

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST ENERGY GP, L.L.C.

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fourth Supplemental Indenture

MASON PIPELINE LIMITED LIABILITY COMPANY

By: MarkWest Hydrocarbon, Inc.,
its Sole Member

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and ChiefFinancial Officer

MARKWEST ENERGY OPERATING COMPANY, L.L.C.

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fourth Supplemental Indenture

MARKWEST BLACKHAWK, L.L.C.
MARKWEST ENERGY APPALACHIA, L.L.C.

MARKWEST ENERGY EAST TEXAS GAS COMPANY, L.L.C.
MARKWEST GAS MARKETING, L.L.C.
MARKWEST GAS SERVICES, L.L.C.
MARKWEST JAVELINA COMPANY, L.L.C.
MARKWEST JAVELINA PIPELINE COMPANY, L.L.C.
MARKWEST LIBERTY GAS GATHERING, L.L.C.
MARKWEST MARKETING, L.L.C.
MARKWEST MOUNTAINEER PIPELINE COPMANY, L.L.C.
MARKWEST NEW MEXICO, L.L.C.
MARKWEST PINNACLE, L.L.C.
MARKWEST PIPELINE COMPANY, L.L.C.
MARKWEST PNG UTILITY, L.L.C.
MARKWEST POWER TEX, L.L.C.
MARKWEST TEXAS PNG UTILITY, L.L.C.

By: MarkWest Energy Operating Company, L.L.C., its Sole Member

By: MarkWest Energy Partners, L.P., its Managing Member

By: MarkWest Energy GP, L.L.C., its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fourth Supplemental Indenture

MARKWEST MICHIGAN PIPELINE COMPANY, L.L.C.
MARKWEST OKLAHOMA GAS COMPANY, L.L.C.

By: MarkWest Energy Operating Company, L.L.C., its Managing Member

By: MarkWest Energy Partners, L.P., its Managing Member

By: MarkWest Energy GP, L.L.C., its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese

Title: Senior Vice President and Chief Financial Officer

MATREX, L.L.C.

By: West Shore Processing Company L.L.C.,
its Sole Member and Manager

By: MarkWest Energy Operating Company, L.L.C.,
its Sole Member and Manager

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fourth Supplemental Indenture

MARKWEST MCALESTER, L.L.C.

By: MarkWest Oklahoma Gas Company, L.L.C.,
its Sole Member

By: MarkWest Energy Operating Company, L.L.C.,
its Managing Member

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

MARKWEST RANGER PIPELINE COMPANY, L.L.C

By: MarkWest Energy Appalachia, L.L.C.,
its Sole Member

By: MarkWest Energy Operating Company, L.L.C.,
its Sole Member

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fourth Supplemental Indenture

WEST SHORE PROCESSING COMPANY L.L.C.

By: MarkWest Energy Operating Company, L.L.C.,
its Sole Member and Manager

By: MarkWest Energy Partners, L.P.,
its Managing Member

By: MarkWest Energy GP, L.L.C.,
its General Partner

By: /s/ Nancy Buese
Name: Nancy Buese
Title: Senior Vice President and Chief Financial Officer

Signature Page to Fourth Supplemental Indenture

WELLS FARGO BANK, NATIONAL ASSOCIATION, AS TRUSTEE

By: /s/ John Stohlmann
Name: John Stohlmann
Title: Vice President

Signature Page to Fourth Supplemental Indenture

Exhibit 31.1

CERTIFICATION

I, Frank M. Semple, certify that:

1. I have reviewed this quarterly report on Form 10-Q of MarkWest Energy Partners, L.P.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.

4. The registrant' s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f), for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant' s internal control over financial reporting that occurred during the registrant' s most recent fiscal quarter (the registrant' s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant' s internal control over financial reporting; and

5. The registrant' s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant' s auditors and the audit committee of registrant' s board of directors (or persons performing the equivalent function):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant' s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant' s internal control over financial reporting.

Date: November 7, 2011

By: /s/ FRANK M. SEMPLE

Frank M. Semple

Chairman, President and Chief Executive Officer

(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Nancy K. Buese, certify that:

1. I have reviewed this quarterly report on Form 10-Q of MarkWest Energy Partners, L.P.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.

4. The registrant' s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f), for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant' s internal control over financial reporting that occurred during the registrant' s most recent fiscal quarter (the registrant' s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant' s internal control over financial reporting; and

5. The registrant' s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant' s auditors and the audit committee of registrant' s board of directors (or persons performing the equivalent function):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant' s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant' s internal control over financial reporting.

Date: November 7, 2011	By:	/s/ NANCY K. BUESE
		Nancy K. Buese
		Senior Vice President & Chief Financial Officer
		(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of MarkWest Energy Partners, L.P. (the "Partnership"), on Form 10-Q for the period ending September 30, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank M. Semple, Chief Executive Officer of the General Partner of the Partnership, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

Date: November 7, 2011

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

This certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document. This certification shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liability under that section. This certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent this Exhibit 32.1 is expressly and specifically incorporated by reference in any such filing.

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of MarkWest Energy Partners, L.P. (the "Partnership") on Form 10-Q for the period ending September 30, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Nancy K. Buese, Chief Financial Officer of the General Partner of the Partnership, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

Date: November 7, 2011

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

This certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document. This certification shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liability under that section. This certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent this Exhibit 32.2 is expressly and specifically incorporated by reference in any such filing.

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Earnings (Loss) Per Common Unit (Details) (USD $) In Thousands, except Share data	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Earnings (Loss) Per Common Unit				
Net income (loss) attributable to the Partnership	$ 140,312	$ (27,151)	$ 134,780	$ 54,576
Less: Income allocable to phantom units	1,287	370	1,288	921
Income (loss) available for common unitholders	$ 139,025	$ (27,521)	$ 133,492	$ 53,655
Weighted average common units outstanding-basic (in units)	78,619,000	71,438,000	76,118,000	69,685,000
Effect of dilutive instruments (in units)	141,000		158,000	146,000
Weighted average common units outstanding-diluted (in units)	78,760,000	71,438,000	76,276,000	69,831,000
Net income (loss) attributable to the Partnership's common unitholders per common unit				
Basic (in dollars per unit)	$ 1.77	$ (0.39)	$ 1.75	$ 0.77
Diluted (in dollars per unit)	$ 1.77	$ (0.39)	$ 1.75	$ 0.77
Anti-dilutive units (in units)		247		

Condensed Consolidated Statements of Operations (USD $) In Thousands, except Per Share data	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Revenue:				
Revenue	$ 400,883	$ 292,370	$ 1,109,632	$ 884,933
Derivative gain (loss)	106,943	(36,959)	61,854	2,707
Total revenue	507,826	255,411	1,171,486	887,640
Operating expenses:				
Purchased product costs	189,284	136,700	497,493	409,119
Derivative (gain) loss related to purchased product costs	(1,274)	19,996	17,866	24,993
Facility expenses	44,236	37,934	124,358	113,266
Derivative gain related to facility expenses	(2,787)	(564)	(2,871)	(436)
Selling, general and administrative expenses	20,162	17,137	60,454	55,064
Depreciation	38,715	31,362	110,280	89,367
Amortization of intangible assets	10,985	10,193	32,632	30,579
Loss on disposal of property, plant and equipment	147	1,937	4,619	2,116
Accretion of asset retirement obligations	557	70	934	282
Total operating expenses	300,025	254,765	845,765	724,350
Income from operations	207,801	646	325,721	163,290
Other income (expense):				
(Loss) earnings from unconsolidated affiliate	(507)		(1,262)	1,517
Interest income	62	422	214	1,185
Interest expense	(26,899)	(26,433)	(83,036)	(75,970)
Amortization of deferred financing costs and discount (a component of interest expense)	(1,002)	(3,625)	(3,873)	(8,517)
Derivative gain related to interest expense				1,871
Loss on redemption of debt	(133)		(43,461)	
Miscellaneous (expense) income, net	(4)	76	127	1,129
Income (loss) before provision for income tax	179,318	(28,914)	194,430	84,505
Provision for income tax expense (benefit):				
Current	3,959	3,533	8,104	10,254
Deferred	21,905	(13,771)	18,338	(45)
Total provision for income tax	25,864	(10,238)	26,442	10,209
Net income (loss)	153,454	(18,676)	167,988	74,296
Net income attributable to non-controlling interest	(13,142)	(8,475)	(33,208)	(19,720)
Net income (loss) attributable to the Partnership	$ 140,312	$ (27,151)	$ 134,780	$ 54,576
Net income (loss) attributable to the Partnership's common unitholders per common unit (Note 14):				
Basic (in dollars per unit)	$ 1.77	$ (0.39)	$ 1.75	$ 0.77
Diluted (in dollars per unit)	$ 1.77	$ (0.39)	$ 1.75	$ 0.77

Weighted average number of outstanding common units:				
Basic (in units)	78,619	71,438	76,118	69,685
Diluted (in units)	78,760	71,438	76,276	69,831
Cash distribution declared per common unit (in dollars per unit)	$ 0.70	$ 0.64	$ 2.02	$ 1.92

Condensed Consolidated Statements of Changes in Equity (USD $) In Thousands	Total	Partners' Capital	Non-controlling Interest
Balance at Dec. 31, 2009	$ 1,379,393	$ 1,096,654	$ 282,739
Balance (in units) at Dec. 31, 2009		66,275	
Increase (Decrease) in Equity			
Share-based compensation activity	8,465	8,465	
Share-based compensation activity (in units)		278	
Excess tax benefits related to share-based compensation	97	97	
Distributions paid	(139,779)	(134,949)	(4,830)
Issuance of units in public offering, net of offering costs	142,255	142,255	
Issuance of units in public offering, net of offering costs (in units)		4,887	
Contributions to MarkWest Liberty Midstream joint venture	148,057		148,057
Net income	74,296	54,576	19,720
Balance at Sep. 30, 2010	1,612,784	1,167,098	445,686
Balance (in units) at Sep. 30, 2010		71,440	
Balance at Dec. 31, 2010	1,536,020	1,070,503	465,517
Balance (in units) at Dec. 31, 2010	71,440	71,440	
Increase (Decrease) in Equity			
Share-based compensation activity	5,213	5,213	
Share-based compensation activity (in units)		275	
Excess tax benefits related to share-based compensation	1,089	1,089	
Distributions paid	(205,030)	(155,931)	(49,099)
Issuance of units in public offering, net of offering costs	323,492	323,492	
Issuance of units in public offering, net of offering costs (in units)		7,475	
Contributions to MarkWest Liberty Midstream joint venture	80,332		80,332
Net income	167,988	134,780	33,208
Balance at Sep. 30, 2011	$ 1,909,104	$ 1,379,146	$ 529,958
Balance (in units) at Sep. 30, 2011	79,190	79,190	

Segment Information (Details 3) (USD $) In Thousands	Sep. 30, 2011	Dec. 31, 2010	Sep. 30, 2010	Dec. 31, 2009
Segment Assets				
Certain cash and cash equivalents	$ 159,177	$ 67,450	$ 98,495	$ 97,752
Fair value of derivatives	72,043	4,762		
Investment in unconsolidated affiliate	27,126	28,688		
Total assets	3,986,201	3,333,362		
Total reportable segments				
Segment Assets				
Total assets	3,769,055	3,208,225		
Southwest Segment				
Segment Assets				
Total assets	1,680,619	1,646,607		
Northeast Segment				
Segment Assets				
Total assets	479,576	244,219		
Liberty Segment				
Segment Assets				
Total assets	1,039,619	743,943		
Gulf Coast Segment				
Segment Assets				
Total assets	569,241	573,456		
Unallocated Segment				
Segment Assets				
Certain cash and cash equivalents	82,626	49,776		
Fair value of derivatives	72,043	4,762		
Investment in unconsolidated affiliate	27,126	28,688		
Other	$ 35,351	$ 41,911		

Subsequent Events	9 Months Ended Sep. 30, 2011
Subsequent Events	
Subsequent Events	**18. Subsequent Events** *Equity Offering* On October 13, 2011, the Partnership completed a public offering of approximately 5.75 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds after deducting underwriting fees and other third-party expenses were approximately $251 million and were used to repay borrowings under the Credit Facility and to provide working capital for general partnership purposes. *Senior Notes Offering and Tender Offer* On October 25, 2011, the Partnership commenced a public offering of $700 million in aggregate principal amount of 6.25% senior unsecured notes due June 2022 ("2022 Senior Notes"). The offering is expected to close on November 3, 2011. Interest on the 2022 Notes is payable semi-annually in arrears on June 15 and December 15, commencing June 15, 2012. The Partnership intends to use the net proceeds from this offering to fund the repurchase of any and all of the $334.4 million outstanding 2018 Senior Notes that are tendered pursuant to a concurrent tender offer, and any remaining net proceeds will be used to provide additional working capital for general partnership purposes. The Partnership has offered to repurchase the 2018 Senior Notes at 112.5% of their principal amounts for all notes tendered prior to November 9, 2011. Any 2018 Senior Notes tendered after November 9, 2011 but prior to November 25, 2011 will be repurchased at 109.5% of their principal amounts.

Condensed Consolidated Balance Sheets (USD $) In Thousands	Sep. 30, 2011	Dec. 31, 2010
Current assets:		
Cash and cash equivalents ($72,171 and $2,913, respectively)	$ 159,177	$ 67,450
Restricted cash ($25,143 and $0, respectively)	25,143	0
Receivables, net ($13,451 and $43,783, respectively)	192,271	179,209
Inventories ($21,919 and $8,431, respectively)	43,381	23,432
Fair value of derivative instruments ($280 and $0, respectively)	29,260	4,345
Deferred income taxes	16,090	16,090
Other current assets ($1,168 and $272, respectively)	8,745	8,020
Total current assets	474,067	298,546
Property, plant and equipment ($1,116,112 and $849,986, respectively)	3,121,547	2,613,027
Less: accumulated depreciation ($67,455 and $38,169, respectively)	(401,729)	(294,003)
Total property, plant and equipment, net	2,719,818	2,319,024
Other long-term assets:		
Restricted cash ($3,007 and $28,001, respectively)	3,007	28,001
Investment in unconsolidated affiliate	27,126	28,688
Intangibles, net of accumulated amortization of $157,183 and $124,568, respectively	614,752	613,578
Goodwill	67,918	9,421
Deferred financing costs, net of accumulated amortization of $13,809 and $11,445, respectively	34,043	32,901
Deferred contract cost, net of accumulated amortization of $2,184 and $1,950, respectively	1,066	1,300
Fair value of derivative instruments	42,783	417
Other long-term assets ($361 and $383, respectively)	1,621	1,486
Total assets	3,986,201	3,333,362
Current liabilities:		
Accounts payable ($35,724 and $5,945, respectively)	183,695	122,473
Accrued liabilities ($68,781 and $64,713, respectively)	168,168	153,869
Deferred income taxes	11	11
Fair value of derivative instruments	65,499	65,489
Total current liabilities	417,373	341,842
Deferred income taxes	28,765	10,427
Fair value of derivative instruments	34,161	66,290
Long-term debt, net of discounts of $1,499 and $1,566, respectively	1,477,963	1,273,434
Other long-term liabilities ($163 and $154, respectively)	118,835	105,349
Commitments and contingencies (Note 11)		
Equity:		
MarkWest Energy Partners, L.P. partners' capital (79,190 and 71,440 common units issued and outstanding, respectively)	1,379,146	1,070,503
Non-controlling interest in consolidated subsidiaries	529,958	465,517
Total equity	1,909,104	1,536,020
Total liabilities and equity	$ 3,986,201	$ 3,333,362

Incentive Compensation Plans (Details) (USD $) In Thousands	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Share-based compensation arrangement by share-based payment award				
Total share-based compensation expense	$ 2,633	$ 3,725	$ 10,938	$ 12,599
Phantom units				
Share-based compensation arrangement by share-based payment award				
Total share-based compensation expense	2,518	3,177	10,611	11,430
Distribution equivalent rights				
Share-based compensation arrangement by share-based payment award				
Total share-based compensation expense	$ 115	$ 548	$ 327	$ 1,169

Derivative Financial Instruments (Tables)	9 Months Ended Sep. 30, 2011

Derivative Financial Instruments

Volume of Derivative Activity

Derivative contracts not designated as hedging instruments	Notional Quantity (net)
Crude oil (bbl)	6,843,759
Natural gas (MMBtu)	14,857,174
NGLs (gal)	138,213,006

Reconciliation of liability recorded for embedded derivative

Fair value of commodity contract	$ 94,652
Inception value for period from April 1, 2015 to December 31, 2022	(53,507)
Derivative liability as of September 30, 2011	$ 41,145

Derivative contracts not designated as hedging instruments

Derivative instruments not designated as hedging instruments and their balance sheet location	Assets September 30, 2011	Assets December 31, 2010	Liabilities September 30, 2011	Liabilities December 31, 2010
Commodity contracts				
Fair value of derivative instruments - current	$ 29,260	$ 4,345	$ (65,499)	$ (65,489)
Fair value of derivative instruments - long-term	42,783	417	(34,161)	(66,290)
Total	$ 72,043	$ 4,762	$ (99,660)	$ (131,779)

Derivative instruments not designated as hedging instruments and the location of gain or (loss) recognized in income	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Revenue: Derivative gain (loss)				
Realized loss	$ (9,809)	$ (1,732)	$ (36,386)	$ (20,551)
Unrealized gain (loss)	116,752	(35,227)	98,240	23,258
Total revenue: derivative gain (loss)	106,943	(36,959)	61,854	2,707
Derivative gain (loss) related to purchased product costs				
Realized loss	(5,989)	(3,946)	(19,436)	(15,117)
Unrealized gain (loss)	7,263	(16,050)	1,570	(9,876)
Total derivative gain (loss) related to purchased product costs	1,274	(19,996)	(17,866)	(24,993)
Derivative gain related to facility expenses				
Unrealized gain	2,787	564	2,871	436
Derivative gain related to interest expense				
Realized gain	–	–	–	2,380
Unrealized loss	–	–	–	(509)
Total derivative gain related to interest expense	–	–	–	1,871
Miscellaneous (expense) income, net				
Unrealized gain	–	103	–	162
Total gain (loss)	$ 111,004	$ (56,288)	$ 46,859	$ (19,817)

Commitments and Contingencies (Details) (Legal- Notice of Probable Violation and proposed Civil penalty, Equitable Production Company, USD $) In Millions, unless otherwise specified	1 Months Ended	
	Mar. 31, 2011 Violations	Jun. 30, 2006 Count
Commitments and Contingencies		
Actual number of counts for which order assessing penalty received	1	
Penalty assessed	$ 0.5	
Corporation		
Commitments and Contingencies		
Actual number of counts of violations of applicable regulations		6
Proposed civil penalty		1.1
Actual number of counts for which order assessing penalty received	4	
Penalty assessed	$ 0.2	

Inventories	9 Months Ended Sep. 30, 2011

Inventories

Inventories

7. Inventories

Inventories consist of the following (in thousands):

	September 30, 2011	December 31, 2010
NGLs	$ 35,567	$ 15,930
Spare parts, materials and supplies	7,814	7,502
Total inventories	$ 43,381	$ 23,432

The increase in NGL inventory primarily relates to the purchase of propane in the Liberty segment. The propane is expected to be sold during the fourth quarter of 2011 and first quarter of 2012.

Fair Value (Tables)

	9 Months Ended Sep. 30, 2011

Fair Value

Derivative instruments carried at fair value

As of September 30, 2011	Assets	Liabilities
Significant other observable inputs (Level 2)		
Commodity contracts	$34,678	$(53,873)
Significant unobservable inputs (Level 3)		
Commodity contracts	33,458	(4,642)
Embedded derivatives in commodity contracts	3,907	(41,145)
Total carrying value in Condensed Consolidated Balance Sheet	$72,043	$(99,660)

As of December 31, 2010	Assets	Liabilities
Significant other observable inputs (Level 2)		
Commodity contracts	$ 52	$ (77,776)
Significant unobservable inputs (Level 3)		
Commodity contracts	3,674	(18,031)
Embedded derivatives in commodity contracts	1,036	(35,972)
Total carrying value in Condensed Consolidated Balance Sheet	$ 4,762	$(131,779)

Rollforward of the balance sheet amounts for assets and liabilities classified within Level 3 of the valuation hierarchy

	Three months ended September 30, 2011	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	$ (22,290)	$ (49,447)
Total gain (realized and unrealized) included in earnings (1)	47,939	8,042
Settlements	3,167	4,167
Fair value at end of period	$ 28,816	$ (37,238)
The amount of total gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ 48,544	$ 8,337

Three months ended September 30, 2010

	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Embedded Derivative in Debt Contract
Fair value at beginning of period	$ 5,348	$ (23,636)	$ (131)
Total (loss) or gain (realized and unrealized) included in earnings (1)	(8,952)	(11,977)	103
Settlements (net)	65	2,298	−
Fair value at end of period	$ (3,539)	$ (33,315)	$ (28)
The amount of total (loss) or gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ (8,592)	$ (11,345)	$ 103

	Nine months ended September 30, 2011	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	$ (14,357)	$ (34,936)
Total gain or (loss) (realized and unrealized) included in earnings (1)	35,402	(14,063)
Settlements	7,771	11,761
Fair value at end of period	$ 28,816	$ (37,238)
The amount of total gain or (loss) for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ 39,196	$ (10,813)

	Nine months ended September 30, 2010			
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Interest Rate Contracts	Embedded Derivative in Debt Contract
Fair value at beginning of period	$ (11,340)	$ (34,199)	$ 509	$ (190)
Total gain or (loss) (realized and unrealized) included in earnings (1)	1,319	(6,857)	1,871	162
Settlements (net)	6,482	7,741	(2,380)	−
Fair value at end of period	$ (3,539)	$ (33,315)	$ −	$ (28)
The amount of total (loss) or gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ (2,712)	$ (4,703)	$ −	$ 162

(1) Gains and losses on Commodity Derivative Contracts classified as Level 3 are recorded in *Derivative gain (loss) related to revenue*. Gains and losses on Embedded Derivatives

in Commodity Contracts are recorded in *Purchased product costs, Derivative (gain) loss related to purchased product costs and Derivative gain related to facility expenses*. Gains on Embedded Derivatives in Debt Contract are recorded in *Miscellaneous (expense) income, net.* Gains on Interest Rate Contracts are recorded in *Derivative gain related to interest expense*.

Inventories (Details) (USD $) In Thousands	Sep. 30, 2011	Dec. 31, 2010
Inventories		
Natural gas liquids	$ 35,567	$ 15,930
Spare parts and supplies	7,814	7,502
Total inventories	$ 43,381	$ 23,432

Business Combination (Details) (USD $)	3 Months Ended		9 Months Ended		3 Months Ended	9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011 Langley Acquisition	Sep. 30, 2011 Langley Acquisition MMcfPerDay Y	Feb. 02, 2011 Langley Acquisition
Business Combination							
Cash purchase price							$ 230,700,000
Capacity of cryogenic natural gas processing plant (in MMcf/d)						100	
Capacity of refrigeration natural gas processing plant (in MMcf/d)						75	
Minimum additional capacity of cryogenic natural gas processing plant by mid-2012 (in MMcf/d)						60	
Purchase price allocation							
Property, plant and equipment					136,525,000	136,525,000	
Goodwill					58,497,000	58,497,000	
Intangibles					33,900,000	33,900,000	
Inventories					1,806,000	1,806,000	
Total					230,728,000	230,728,000	
Estimated remaining useful life of intangibles (in years)						12	
Revenue	400,883,000	292,370,000	1,109,632,000	884,933,000	6,200,000	16,300,000	
Net (loss) income	$ 153,454,000	$ (18,676,000)	$ 167,988,000	$ 74,296,000	$ 2,100,000	$ 5,700,000	

Variable Interest Entities (Tables)	9 Months Ended Sep. 30, 2011
Variable Interest Entities	
Consolidated assets and liabilities attributable to VIEs, excluding intercompany balances	

	As of September 30, 2011		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ 69,808	$ 2,363	$ 72,171
Restricted cash (current)	25,143	−	25,143
Receivables, net	12,116	1,335	13,451
Inventories	21,919	−	21,919
Fair value of derivative instruments (current)	280	−	280
Other current assets	1,168	−	1,168
Property, plant and equipment, net of accumulated depreciation of $53,468 and $13,987, respectively	906,199	142,458	1,048,657
Restricted cash (long-term)	3,007	−	3,007
Other long-term assets	259	102	361
Total assets	$ 1,039,899	$ 146,258	$1,186,157
LIABILITIES			
Accounts payable	$ 35,644	$ 80	$ 35,724
Accrued liabilities	67,849	932	68,781
Other long-term liabilities	91	72	163
Total liabilities	$ 103,584	$ 1,084	$ 104,668

	As of December 31, 2010		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ −	$ 2,913	$ 2,913
Receivables, net	42,181	1,602	43,783
Inventories	8,431	−	8,431
Other current assets	271	1	272
Property, plant and equipment, net of accumulated depreciation of $28,869 and $9,300, respectively	664,778	147,039	811,817
Restricted cash (long-term)	28,001	−	28,001
Other long-term assets	281	102	383
Total assets	$ 743,943	$ 151,657	$895,600
LIABILITIES			
Accounts payable	$ 5,945	$ −	$ 5,945
Accrued liabilities	63,450	1,263	64,713
Other long-term liabilities	86	68	154
Total liabilities	$ 69,481	$ 1,331	$ 70,812

Incentive Compensation Plans	9 Months Ended Sep. 30, 2011

Incentive Compensation Plans

Incentive Compensation Plans

12. Incentive Compensation Plans

Compensation Expense

Total compensation expense recorded for share-based pay arrangements for the three and nine months ended September 30, 2011 and 2010 is as follows (in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Phantom units	$ 2,518	$ 3,177	$ 10,611	$ 11,430
Distribution equivalent rights	115	548	327	1,169
Total compensation expense	$ 2,633	$ 3,725	$ 10,938	$ 12,599

Business Combination

Business Combination	9 Months Ended Sep. 30, 2011
Business Combination	
Business Combination	

3. Business Combination

Langley Acquisition

On February 1, 2011, the Partnership acquired natural gas processing and NGL transportation assets from EQT Gathering, LLC, a subsidiary of EQT Corporation (together with all of its affiliates, "EQT"), for a cash purchase price of approximately $230.7 million. The assets acquired include natural gas processing facilities located near Langley, Kentucky, consisting of a cryogenic natural gas processing plant with a capacity of approximately 100 MMcf/d and a refrigeration natural gas processing plant with a capacity of approximately 75 MMcf/d (together, the "Langley Processing Facilities"), a partially constructed NGL pipeline (the "Ranger Pipeline") that will extend through parts of Kentucky and West Virginia, and certain other related assets. The acquired assets do not include certain residue gas compression and transportation facilities at the same location as the Langley Processing Facilities. This acquisition is referred to as the Langley Acquisition. In connection with the Langley Acquisition, the Partnership will complete the construction of the Ranger Pipeline to connect the Langley Processing Facilities to the Partnership' s existing pipeline that transports NGLs to its Siloam fractionation facility in South Shore, Kentucky.

Concurrently with the closing of the Langley Acquisition, the Partnership entered into a long-term agreement to process certain natural gas owned or controlled by EQT at the Langley Processing Facilities. The processing agreement requires the Partnership to install an additional cryogenic natural gas processing plant with a capacity of at least 60 MMcf/d in 2012. The Partnership exchanges the NGLs produced at the Langley Processing Facilities for fractionated products from its Siloam facility and markets the fractionated products on behalf of EQT in accordance with a long-term NGL exchange and marketing agreement. As a result of the acquisition, the Partnership has significantly expanded its midstream operations in the liquids-rich gas areas of the Appalachian Basin.

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

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

Property, plant and equipment	$ 136,525
Goodwill	58,497
Intangibles	33,900
Inventories	1,806
Total	$ 230,728

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

Intangible assets consist of an identifiable customer contract and relationship. The acquired intangibles will be amortized on a straight-line basis over the estimated remaining useful life of approximately twelve years.

The results of operations from the Langley Acquisition are included in the condensed consolidated financial statements from the acquisition date. Revenue and net income related to the Langley Acquisition were approximately $6.2 million and $2.1 million, respectively, for the quarter ended September 30, 2011 and $16.3 million and $5.7 million, respectively, for the nine months ended September 30, 2011.

Pro forma financial results that give effect to the Langley Acquisition are not presented as it is impracticable to obtain the necessary information. EQT did not operate the acquired assets as a stand-alone business, and therefore historical financial information that is consistent with the operations under the current agreements is not available or meaningful.

Segment Information (Tables)

Segment Information

Schedule of operating income and capital expenditures of geographical segments

9 Months Ended Sep. 30, 2011

Three months ended September 30, 2011:	Southwest	Northeast	Liberty	Gulf Coast	Total
Segment revenue	$ 241,998	$ 55,920	$ 78,586	$ 26,868	$ 403,372
Purchased product costs	141,067	15,947	32,270	–	189,284
Net operating margin	100,931	39,973	46,316	26,868	214,088
Facility expenses	21,043	6,879	9,108	9,798	46,828
Portion of operating income attributable to non-controlling interests	1,227	–	18,223	–	19,450
Operating income before items not allocated to segments	$ 78,661	$ 33,094	$ 18,985	$ 17,070	$ 147,810

Three months ended September 30, 2010:	Southwest	Northeast	Liberty	Gulf Coast	Total
Segment revenue	$ 159,044	$ 83,400	$ 28,606	$ 21,320	$ 292,370
Purchased product costs	74,835	55,879	5,986	–	136,700
Net operating margin	84,209	27,521	22,620	21,320	155,670
Facility expenses	20,659	5,268	5,668	8,785	40,380
Portion of operating income attributable to non-controlling interests	1,906	–	6,772	–	8,678
Operating income before items not allocated to segments	$ 61,644	$ 22,253	$ 10,180	$ 12,535	$ 106,612

Nine months ended September 30, 2011:	Southwest	Northeast	Liberty	Gulf Coast	Total
Segment revenue	$679,347	$201,687	$168,142	$ 73,310	$1,122,486
Purchased product costs	373,251	72,527	51,715	–	497,493
Net operating margin	306,096	129,160	116,427	73,310	624,993
Facility expenses	62,055	19,402	22,875	27,100	131,432
Portion of operating income attributable to non-controlling interests	3,745	–	45,782	–	49,527
Operating income before items not allocated to segments	$240,296	$109,758	$ 47,770	$ 46,210	$ 444,034
Capital expenditures	$ 80,069	$ 17,768	$256,877	$ 1,282	$ 355,996
Capital expenditures not allocated to segments					3,930
Total capital expenditures					$ 359,926

Nine months ended September 30, 2010:	Southwest	Northeast	Liberty	Gulf Coast	Total
Segment revenue	$ 479,051	$ 276,570	$ 66,354	$ 62,958	$ 884,933
Purchased product costs	220,849	179,700	8,570	–	409,119
Net operating margin	258,202	96,870	57,784	62,958	475,814
Facility expenses	60,543	14,555	19,121	23,875	118,094
Portion of operating income attributable to non-controlling interests	4,962	–	15,617	–	20,579
Operating income before items not allocated to segments	$ 192,697	$ 82,315	$ 23,046	$ 39,083	$ 337,141

Capital expenditures	$ 89,949	$ 1,918	$ 275,620	$ 3,418	$ 370,905
Capital expenditures not allocated to segments					3,268
Total capital expenditures					$ 374,173

Reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to (loss) income before provision for income tax

	Three months ended September 30, 2011	2010
Total segment revenue	$ 403,372	$ 292,370
Derivative gain (loss) not allocated to segments	106,943	(36,959)
Revenue deferral adjustment (1)	(2,489)	–
Total revenue	$ 507,826	$ 255,411
Operating income before items not allocated to segments	$ 147,810	$ 106,612
Portion of operating income attributable to non-controlling interests	19,450	8,678
Derivative gain (loss) not allocated to segments	111,004	(56,391)
Revenue deferral adjustment (1)	(2,489)	–
Compensation expense included in facility expenses not allocated to segments	(263)	(404)
Facility expenses adjustments	2,855	2,850
Selling, general and administrative expenses	(20,162)	(17,137)
Depreciation	(38,715)	(31,362)
Amortization of intangible assets	(10,985)	(10,193)
Loss on disposal of property, plant and equipment	(147)	(1,937)
Accretion of asset retirement obligations	(557)	(70)
Income from operations	207,801	646
Loss from unconsolidated affiliate	(507)	–
Interest income	62	422
Interest expense	(26,899)	(26,433)
Amortization of deferred financing costs and discount (a component of interest expense)	(1,002)	(3,625)
Loss on redemption of debt	(133)	–
Miscellaneous (expense) income, net	(4)	76
Income (loss) before provision for income tax	$ 179,318	$ (28,914)

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the three months ended September 30, 2011, approximately $0.2 million and $2.3 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration

received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

	Nine months ended September 30, 2011	2010
Total segment revenue	$ 1,122,486	$ 884,933
Derivative gain not allocated to segments	61,854	2,707
Revenue deferral adjustment (1)	(12,854)	–
Total revenue	$ 1,171,486	$ 887,640
Operating income before items not allocated to segments	$ 444,034	$ 337,141
Portion of operating income attributable to non-controlling interests	49,527	20,579
Derivative gain (loss) not allocated to segments	46,859	(21,850)
Revenue deferral adjustment (1)	(12,854)	–
Compensation expense included in facility expenses not allocated to segments	(1,491)	(1,412)
Facility expenses adjustments	8,565	6,240
Selling, general and administrative expenses	(60,454)	(55,064)
Depreciation	(110,280)	(89,367)
Amortization of intangible assets	(32,632)	(30,579)
Loss on disposal of property, plant and equipment	(4,619)	(2,116)
Accretion of asset retirement obligations	(934)	(282)
Income from operations	325,721	163,290
(Loss) earnings from unconsolidated affiliate	(1,262)	1,517
Interest income	214	1,185
Interest expense	(83,036)	(75,970)
Amortization of deferred financing costs and discount (a component of interest expense)	(3,873)	(8,517)
Derivative gain related to interest expense	–	1,871
Loss on redemption of debt	(43,461)	–
Miscellaneous income, net	127	1,129
Income before provision for income tax	$ 194,430	$ 84,505

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the nine months ended September 30, 2011, approximately $6.9 million and $5.9 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

Segment assets information

SEGMENT ASSETS:

	September 30, 2011	December 31, 2010
Southwest	$ 1,680,619	$ 1,646,607
Northeast	479,576	244,219
Liberty	1,039,619	743,943
Gulf Coast	569,241	573,456
Total segment assets	3,769,055	3,208,225
Assets not allocated to segments:		
Certain cash and cash equivalents	82,626	49,776
Fair value of derivatives	72,043	4,762
Investment in unconsolidated affiliate	27,126	28,688
Other (1)	35,351	41,911
Total assets	$ 3,986,201	$ 3,333,362

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

Long-Term Debt	9 Months Ended Sep. 30, 2011

Long-Term Debt

Long-Term Debt

9. Long-Term Debt

Debt is summarized below (in thousands):

	September 30, 2011	December 31, 2010
Credit Facility		
Revolving credit facility, 4.25% interest due September 2016	$ 145,100	$ –
Senior Notes (1)		
Senior Notes, 8.5% interest, net of discount of $0 and $642, respectively, issued July 2006 and due July 2016	–	274,358
Senior Notes, 8.75% interest, net of discount of $555 and $924, respectively, issued April and May 2008 and due April 2018	333,807	499,076
Senior Notes, 6.75% interest, issued November 2010 and due November 2020	500,000	500,000
Senior Notes, 6.5% interest, net of discount of $944, issued February and March 2011 and due August 2021	499,056	–
Total long-term debt	$ 1,477,963	$ 1,273,434

(1) The estimated aggregate fair value of the senior notes (collectively, the "Senior Notes") was approximately $1,350.2 million and $1,333.9 million as of September 30, 2011 and December 31, 2010, respectively, based on quoted market prices.

Credit Facility

On June 15, 2011, the Partnership executed a joinder agreement to the Credit Facility to include an additional member in the bank group and to exercise a portion of the accordion feature under the Credit Facility, thereby increasing the borrowing capacity of the Credit Facility to $745 million and reducing the uncommitted accordion feature to $155 million.

On September 7, 2011, the Partnership amended the Credit Facility, increasing the borrowing capacity of the Credit Facility to $750 million, increasing the uncommitted accordion feature to $250 million, reducing the interest rate ranges by 75 basis points, and extending the maturity date to September 2016.

Under the provisions of the Credit Facility, the Partnership is subject to a number of restrictions and covenants. These covenants are used to calculate the available borrowing capacity on a quarterly basis. The Credit Facility is guaranteed by the Partnership' s wholly-owned subsidiaries and collateralized by substantially all of the Partnership' s assets and those of its wholly-owned subsidiaries. As of September 30, 2011, the Partnership had $27.3 million of letters of credit outstanding under the Credit Facility and approximately $577.6 million available for borrowing.

Senior Notes

On February 24, 2011, the Partnership completed a public offering of $300 million in aggregate principal amount of 6.5% senior unsecured notes ("2021 Senior Notes"), which were issued at par. On March 10, 2011, the Partnership completed a follow-on public offering of an additional $200 million in aggregate principal amount of 2021 Senior Notes, which were issued at 99.5% of par and are treated as a single class of debt securities with the 2021 Senior Notes issued on February 24, 2011. The 2021 Senior Notes mature on August 15, 2021, and interest is payable semi-annually in arrears on February 15 and August 15, commencing August 15, 2011. The Partnership received aggregate net proceeds of approximately $492 million from the 2021 Senior Notes offerings after deducting the underwriting fees and other third-party expenses. The Partnership used the net proceeds from these offerings to fund the repurchase of approximately $272.2 million in aggregate principal amount of the Partnership' s 8.5% senior unsecured notes due 2016 (the "2016 Senior Notes") and approximately $165.6 million in aggregate principal amount of the Partnership' s 8.75% senior unsecured notes due 2018 (the "2018 Senior Notes"). The remaining proceeds were used to repay borrowings under the Credit Facility. The Partnership recorded a pre-tax loss on redemption of debt of approximately $43.3 million in the first quarter of 2011 related to the repurchase of the 2016 Senior Notes and 2018 Senior Notes, which consisted of approximately $3.8 million for the non-cash write off of the unamortized discount and deferred finance costs and approximately $39.5 million for the payment of the related tender premiums and third-party expenses. On July 15, 2011, the Partnership repurchased the remaining 2016 Senior Notes. The Partnership recorded a pre-tax loss on redemption of debt of approximately $0.1 million in the third quarter of 2011 for the payment of tender premiums and third-party expenses related to the repurchase of the remaining 2016 Senior Notes.

Earnings (Loss) Per Common Unit	9 Months Ended Sep. 30, 2011
Earnings (Loss) Per Common Unit	
Earnings (Loss) Per Common Unit	**14. Earnings (Loss) Per Common Unit**

The following table shows the computation of basic and diluted net income (loss) per common unit for the three and nine months ended September 30, 2011 and 2010, and the weighted-average units used to compute diluted net income (loss) per common unit (in thousands, except per unit data):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Net income (loss) attributable to the Partnership	$ 140,312	$ (27,151)	$ 134,780	$ 54,576
Less: Income allocable to phantom units	1,287	370	1,288	921
Income (loss) available for common unitholders	$ 139,025	$ (27,521)	$ 133,492	$ 53,655
Weighted average common units outstanding - basic	78,619	71,438	76,118	69,685
Effect of dilutive instruments (1)	141	–	158	146
Weighted average common units outstanding - diluted (1)	78,760	71,438	76,276	69,831
Net income (loss) attributable to the Partnership' s common unitholders per common unit				
Basic	$ 1.77	$ (0.39)	$ 1.75	$ 0.77
Diluted	$ 1.77	$ (0.39)	$ 1.75	$ 0.77

(1) Dilutive instruments include TSR Performance Units and are based on the number of units, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For the three months ended September 30, 2010, 247 units were excluded from the calculation of diluted units because the impact was anti-dilutive.

Equity	9 Months Ended Sep. 30, 2011

Equity

Equity

10. Equity

Equity Offering

On January 14, 2011, the Partnership completed a public offering of approximately 3.45 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriter' s over-allotment option. Net proceeds after deducting the underwriting fees and third-party offering expenses were approximately $138 million and were used to partially fund the Partnership' s ongoing capital expenditure program, including a portion of the costs associated with the Langley Acquisition (see Note 3).

On July 13, 2011, the Partnership completed a public offering of approximately 4.0 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds after deducting underwriting fees and other third-party offering expenses were approximately $185 million and were used to repay borrowings under the Credit Facility and to partially fund the Partnership' s ongoing capital expenditure program.

Distributions of Available Cash

Quarter Ended	Distribution Per Common Unit		Declaration Date	Record Date	Payment Date
September 30, 2011	$	0.73	October 18, 2011	November 7, 2011	November 14, 2011
June 30, 2011	$	0.70	July 21, 2011	August 1, 2011	August 12, 2011
March 31, 2011	$	0.67	April 21, 2011	May 2, 2011	May 13, 2011
December 31, 2010	$	0.65	January 27, 2011	February 7, 2011	February 14, 2011

Incentive Compensation Plans (Tables)	9 Months Ended Sep. 30, 2011

Incentive Compensation Plans

Compensation expense recorded for share-based pay arrangements

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Phantom units	$ 2,518	$ 3,177	$ 10,611	$ 11,430
Distribution equivalent rights	115	548	327	1,169
Total compensation expense	$ 2,633	$ 3,725	$ 10,938	$ 12,599

Goodwill	9 Months Ended Sep. 30, 2011

Goodwill.

Goodwill

8. Goodwill

Changes in goodwill are summarized as follows (in thousands):

	Southwest	Northeast	Gulf Coast	Total
Gross goodwill as of December 31, 2010	$ 24,324	$ 3,948	$ 9,854	$38,126
Acquisition(1)	–	58,497	–	58,497
Gross Goodwill as of September 30, 2011	24,324	62,445	9,854	96,623
Cumulative impairment (2)	(18,851)	–	(9,854)	(28,705)
Balance as of September 30, 2011	$ 5,473	$ 62,445	$ –	$67,918

(1) Represents goodwill associated with the Langley Acquisition (see Note 3).
(2) All impairments recorded in the fourth quarter of 2008.

Segment Information (Details 2) (USD $) In Thousands	3 Months Ended Sep. 30, 2011	3 Months Ended Sep. 30, 2010	9 Months Ended Sep. 30, 2011	9 Months Ended Sep. 30, 2010
Segment information				
Revenue	$ 400,883	$ 292,370	$ 1,109,632	$ 884,933
Derivative gain (loss) not allocated to segments	106,943	(36,959)	61,854	2,707
Total revenue	507,826	255,411	1,171,486	887,640
Portion of operating income attributable to non-controlling interests	19,450	8,678	49,527	20,579
Selling, general and administrative expenses	(20,162)	(17,137)	(60,454)	(55,064)
Depreciation	(38,715)	(31,362)	(110,280)	(89,367)
Amortization of intangible assets	(10,985)	(10,193)	(32,632)	(30,579)
Loss on disposal of property, plant and equipment	(147)	(1,937)	(4,619)	(2,116)
Accretion of asset retirement obligations	(557)	(70)	(934)	(282)
Income from operations	207,801	646	325,721	163,290
(Loss) earnings from unconsolidated affiliate	(507)		(1,262)	1,517
Interest income	62	422	214	1,185
Interest expense	(26,899)	(26,433)	(83,036)	(75,970)
Derivative gain related to interest expense				1,871
Amortization of deferred financing costs and discount (a component of interest expense)	(1,002)	(3,625)	(3,873)	(8,517)
Loss on redemption of debt	(133)		(43,461)	
Miscellaneous (expense) income, net	(4)	76	127	1,129
Income (loss) before provision for income tax	179,318	(28,914)	194,430	84,505
Total reportable segments				
Segment information				
Revenue	403,372	292,370	1,122,486	884,933
Portion of operating income attributable to non-controlling interests	19,450	8,678	49,527	20,579
Income from operations	147,810	106,612	444,034	337,141
Southwest Segment				
Segment information				
Revenue	241,998	159,044	679,347	479,051
Portion of operating income attributable to non-controlling interests	1,227	1,906	3,745	4,962
Revenue deferral adjustment	(200)		(6,900)	
Income from operations	78,661	61,644	240,296	192,697
Northeast Segment				
Segment information				
Revenue	55,920	83,400	201,687	276,570
Revenue deferral adjustment	(2,300)		(5,900)	
Income from operations	33,094	22,253	109,758	82,315
Unallocated Segment				
Segment information				
Derivative gain (loss) not allocated to segments	106,943	(36,959)	61,854	2,707
Derivative (loss) gain not allocated to segments	111,004	(56,391)	46,859	(21,850)

Revenue deferral adjustment	(2,489)		(12,854)	
Compensation expense included in facility expenses not allocated to segments	(263)	(404)	(1,491)	(1,412)
Facility expenses adjustments	$ 2,855	$ 2,850	$ 8,565	$ 6,240

Organization and Basis of Presentation	9 Months Ended Sep. 30, 2011
Organization and Basis of Presentation	
Organization and Basis of Presentation	

1. Organization and Basis of Presentation

MarkWest Energy Partners, L.P. was formed in 2002 as a Delaware limited partnership. The Partnership is 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 extensive natural gas gathering, processing and transmission operations in the southwest, Gulf Coast, and northeast regions of the United States, including the Marcellus Shale, and is the largest natural gas processor and fractionator in the Appalachian region.

These unaudited condensed consolidated financial statements have been prepared in accordance with the rules and regulations of the SEC for interim financial reporting. Accordingly, certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted. These condensed consolidated financial statements should be read in conjunction with the Partnership' s consolidated financial statements included in the Partnership' s Annual Report on Form 10-K for the year ended December 31, 2010. In management' s opinion, the Partnership has made all adjustments necessary for a fair presentation of its results of operations, financial position and cash flows for the periods shown. These adjustments are of a normal recurring nature. Finally, results for the three and nine months ended September 30, 2011 are not necessarily indicative of results for the full year 2011, or any other future period.

The Partnership' s unaudited condensed consolidated financial statements include all majority-owned or majority-controlled subsidiaries. In addition, MarkWest Liberty Midstream & Resources L.L.C. ("MarkWest Liberty Midstream") and MarkWest Pioneer, L.L.C. ("MarkWest Pioneer"), VIEs for which the Partnership has been determined to be the primary beneficiary, are included in the condensed consolidated financial statements (see Note 4). All significant intercompany investments, accounts and transactions have been eliminated. The Partnership' s investment in Centrahoma, LLC, in which the Partnership exercises significant influence but does not control, and is not the primary beneficiary, is accounted for using the equity method.

Variable Interest Entities

9 Months Ended Sep. 30, 2011

Variable Interest Entities

Variable Interest Entities

4. Variable Interest Entities

MarkWest Liberty Midstream

MarkWest Liberty Midstream operates in the natural gas midstream business in and around the Marcellus Shale in western Pennsylvania and northern West Virginia. Effective January 1, 2011, equity interests in the entity are owned 51% by the Partnership and 49% by M&R MWE Liberty, LLC ("M&R"), an affiliate of The Energy & Minerals Group and its affiliated funds.

As of September 30, 2011, the cumulative capital contributed to MarkWest Liberty Midstream by each member is proportionate to its respective ownership interest ("Equalization"). However, until the third quarter of 2011, the cumulative capital contributed by M&R had exceeded its ownership interest. Under the terms of the joint venture agreement, M&R received a special $1.3 million allocation of net income from MarkWest Liberty Midstream during the nine months of 2011 due to its excess contributions. The allocation is recorded in *Net income attributable to non-controlling interest*.

MarkWest Pioneer

MarkWest Pioneer is the owner and operator of the Arkoma Connector Pipeline. Equity interests in the entity are shared equally by the Partnership and Arkoma Pipeline Partners, LLC.

Financial Statement Impact of VIEs

As the primary beneficiary of MarkWest Liberty Midstream and MarkWest Pioneer, the Partnership consolidates the entities and recognizes non-controlling interests. The following tables show the consolidated assets and liabilities attributable to VIEs, excluding intercompany balances, as of September 30, 2011 and December 31, 2010 (in thousands):

	As of September 30, 2011		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ 69,808	$ 2,363	$ 72,171
Restricted cash (current)	25,143	−	25,143
Receivables, net	12,116	1,335	13,451
Inventories	21,919	−	21,919
Fair value of derivative instruments (current)	280	−	280
Other current assets	1,168	−	1,168
Property, plant and equipment, net of accumulated depreciation of $53,468 and $13,987, respectively	906,199	142,458	1,048,657
Restricted cash (long-term)	3,007	−	3,007
Other long-term assets	259	102	361
Total assets	$ 1,039,899	$ 146,258	$1,186,157
LIABILITIES			
Accounts payable	$ 35,644	$ 80	$ 35,724
Accrued liabilities	67,849	932	68,781
Other long-term liabilities	91	72	163

Total liabilities	$ 103,584	$ 1,084	$ 104,668

	As of December 31, 2010		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ −	$ 2,913	$ 2,913
Receivables, net	42,181	1,602	43,783
Inventories	8,431	−	8,431
Other current assets	271	1	272
Property, plant and equipment, net of accumulated depreciation of $28,869 and $9,300, respectively	664,778	147,039	811,817
Restricted cash (long-term)	28,001	−	28,001
Other long-term assets	281	102	383
Total assets	$ 743,943	$ 151,657	$ 895,600
LIABILITIES			
Accounts payable	$ 5,945	$ −	$ 5,945
Accrued liabilities	63,450	1,263	64,713
Other long-term liabilities	86	68	154
Total liabilities	$ 69,481	$ 1,331	$ 70,812

The assets of the VIEs are the property of the respective entities and are not available to the Partnership for any other purpose, including as collateral for its secured debt (see Note 9 and Note 16). VIE asset balances can only be used to settle obligations of each respective VIE. The liabilities of the VIEs do not represent additional claims against the Partnership' s general assets, and the creditors or beneficial interest holders of the VIE do not have recourse to the general credit of the Partnership. The Partnership' s Liberty segment includes the results of operations of MarkWest Liberty Midstream and the Partnership' s Southwest segment includes the results of operations of MarkWest Pioneer (see Note 15). The cash flow information for MarkWest Liberty Midstream and MarkWest Pioneer comprise substantially all of the cash flow information of the Partnership' s non-guarantor subsidiaries (see Note 16). The Partnership' s maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment, any additional capital contribution commitments and any operating expense incurred by the subsidiary operator in excess of its compensation received for the performance of the operating services. The Partnership did not provide any financial support to the VIEs that it was not contractually obligated to provide during the nine months ended September 30, 2011 and 2010.

Derivative Financial Instruments (Details) (USD $)	3 Months Ended Sep. 30, 2011 MMBTU DthPerDay gal bbl	Sep. 30, 2010	9 Months Ended Sep. 30, 2011 MMBTU DthPerDay gal bbl	Sep. 30, 2010	Dec. 31, 2010
Derivative financial instruments					
Notional quantity of crude oil contract (in bbl)	6,843,759		6,843,759		
Notional quantity of natural gas contract (in MMBtu)	14,857,174		14,857,174		
Notional quantity of NGL contracts (in gal)	138,213,006		138,213,006		
Notional amount for embedded derivative in commodity contract (in Dth per day)	9,000		9,000		
Derivative contracts not designated as hedging instruments					
Fair value of derivative instruments - current assets	$ 29,260,000		$ 29,260,000		$ 4,345,000
Fair value of derivative instruments - long-term assets	42,783,000		42,783,000		417,000
Fair value of derivative instruments - current liabilities	(65,499,000)		(65,499,000)		(65,489,000)
Fair value of derivative liabilities - long-term liabilities	(34,161,000)		(34,161,000)		(66,290,000)
Total derivative assets	72,043,000		72,043,000		4,762,000
Total derivative liabilities	(99,660,000)		(99,660,000)		(131,779,000)
Total Revenue: derivative gain (loss)	106,943,000	(36,959,000)	61,854,000	2,707,000	
Total derivative gain (loss) related to purchased product costs	1,274,000	(19,996,000)	(17,866,000)	(24,993,000)	
Derivative gain related to facility expenses	2,787,000	564,000	2,871,000	436,000	
Derivative gain related to interest expense				1,871,000	
Total gain (loss)	111,004,000	(56,288,000)	46,859,000	(19,817,000)	
Premium payments, net of amortization	1,200,000		1,200,000		
Derivative instruments not designated as hedging instruments					
Derivative contracts not designated as hedging instruments					
Fair value of derivative instruments - current assets	29,260,000		29,260,000		4,345,000
Fair value of derivative instruments - long-term assets	42,783,000		42,783,000		417,000
Fair value of derivative instruments - current liabilities	(65,499,000)		(65,499,000)		(65,489,000)

Fair value of derivative liabilities - long-term liabilities	(34,161,000)		(34,161,000)		(66,290,000)
Total derivative assets	72,043,000		72,043,000		4,762,000
Total derivative liabilities	(99,660,000)		(99,660,000)		(131,779,000)
Derivative instruments not designated as hedging instruments | Derivative revenue					
Derivative contracts not designated as hedging instruments					
Realized gain (loss)	(9,809,000)	(1,732,000)	(36,386,000)	(20,551,000)	
Unrealized gain (loss)	116,752,000	(35,227,000)	98,240,000	23,258,000	
Total Revenue: derivative gain (loss)	106,943,000	(36,959,000)	61,854,000	2,707,000	
Derivative instruments not designated as hedging instruments | Derivative related to purchased product costs					
Derivative contracts not designated as hedging instruments					
Realized gain (loss)	(5,989,000)	(3,946,000)	(19,436,000)	(15,117,000)	
Unrealized gain (loss)	7,263,000	(16,050,000)	1,570,000	(9,876,000)	
Total derivative gain (loss) related to purchased product costs	1,274,000	(19,996,000)	(17,866,000)	(24,993,000)	
Derivative instruments not designated as hedging instruments | Derivative related to facility expenses					
Derivative contracts not designated as hedging instruments					
Unrealized (loss) gain	2,787,000	564,000	2,871,000	436,000	
Derivative instruments not designated as hedging instruments | Derivative related to interest expense					
Derivative contracts not designated as hedging instruments					
Realized gain (loss)				2,380,000	
Unrealized gain (loss)				(509,000)	
Derivative gain related to interest expense				1,871,000	
Derivative instruments not designated as hedging instruments | Miscellaneous income, net					
Derivative contracts not designated as hedging instruments					
Unrealized (loss) gain		103,000		162,000	
Derivative revenue | Commodity contracts (net)					
Derivative contracts not designated as hedging instruments					
Amortization of premium payments	1,200,000	500,000	3,300,000	1,600,000	

Embedded derivative in natural gas processing and purchase contract.		
Derivative financial instruments		
Estimated fair value of embedded derivative contract liability including portion allocable to host processing agreement	94,652,000	94,652,000
Inception value for period from April 1, 2015 to December 31, 2022	53,507,000	53,507,000
Recorded value of embedded derivative contract liability	41,145,000	41,145,000
Embedded derivative in electricity purchase contract		
Derivative financial instruments		
Estimated fair value of embedded derivative contract asset	$ 3,900,000	$ 3,900,000

Equity (Tables)

Equity

Distributions of Available Cash

9 Months Ended Sep. 30, 2011

Quarter Ended	Distribution Per Common Unit	Declaration Date	Record Date	Payment Date
September 30, 2011	$ 0.73	October 18, 2011	November 7, 2011	November 14, 2011
June 30, 2011	$ 0.70	July 21, 2011	August 1, 2011	August 12, 2011
March 31, 2011	$ 0.67	April 21, 2011	May 2, 2011	May 13, 2011
December 31, 2010	$ 0.65	January 27, 2011	February 7, 2011	February 14, 2011

Subsequent Events (Details) (USD $) Share data in Thousands, unless otherwise specified	1 Months Ended		9 Months Ended		1 Months Ended				1 Months Ended
	Jul. 31, 2011	Jan. 31, 2011	Sep. 30, 2011	Sep. 30, 2010	Oct. 31, 2011 Issued common units	Oct. 31, 2011 Repurchase of debt Senior notes due 2018	Oct. 31, 2011 Issuance of debt 6.25% senior unsecured notes due June 2022	Oct. 25, 2011 6.25% senior unsecured notes due June 2022	Oct. 31, 2011 Senior notes due 2018
Subsequent Events									
Common units issued representing limited partnership interests (in units)	4,000	3,450			5,750				
Proceeds from issuance of common units, net of expenses			$ 323,492,000	$ 142,255,000	$ 251,000,000				
Amount borrowed							700,000,000		
Debt instrument, stated interest rate percentage (as a percent)								6.25%	
Debt instrument tender offer amount									$ 334,400,000
Repurchase price as percentage of principal amount for notes tendered prior to November 9, 2011						112.50%			
Repurchase price as percentage of principal amount for notes tendered after November 9, 2011 but prior to November 25, 2011						109.50%			

Segment Information (Details) (USD $) In Thousands	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Segment information				
Revenue	$ 400,883	$ 292,370	$ 1,109,632	$ 884,933
Purchased product costs	189,284	136,700	497,493	409,119
Facility expenses	44,236	37,934	124,358	113,266
Portion of operating income attributable to non-controlling interests	19,450	8,678	49,527	20,579
Income from operations	207,801	646	325,721	163,290
Capital expenditures			359,926	374,173
Total reportable segments				
Segment information				
Revenue	403,372	292,370	1,122,486	884,933
Purchased product costs	189,284	136,700	497,493	409,119
Net operating margin	214,088	155,670	624,993	475,814
Facility expenses	46,828	40,380	131,432	118,094
Portion of operating income attributable to non-controlling interests	19,450	8,678	49,527	20,579
Income from operations	147,810	106,612	444,034	337,141
Capital expenditures			355,996	370,905
Southwest Segment				
Segment information				
Revenue	241,998	159,044	679,347	479,051
Purchased product costs	141,067	74,835	373,251	220,849
Net operating margin	100,931	84,209	306,096	258,202
Facility expenses	21,043	20,659	62,055	60,543
Portion of operating income attributable to non-controlling interests	1,227	1,906	3,745	4,962
Income from operations	78,661	61,644	240,296	192,697
Capital expenditures			80,069	89,949
Northeast Segment				
Segment information				
Revenue	55,920	83,400	201,687	276,570
Purchased product costs	15,947	55,879	72,527	179,700
Net operating margin	39,973	27,521	129,160	96,870
Facility expenses	6,879	5,268	19,402	14,555
Income from operations	33,094	22,253	109,758	82,315
Capital expenditures			17,768	1,918
Liberty Segment				
Segment information				
Revenue	78,586	28,606	168,142	66,354
Purchased product costs	32,270	5,986	51,715	8,570
Net operating margin	46,316	22,620	116,427	57,784

Facility expenses	9,108	5,668	22,875	19,121
Portion of operating income attributable to non-controlling interests	18,223	6,772	45,782	15,617
Income from operations	18,985	10,180	47,770	23,046
Capital expenditures			256,877	275,620
Gulf Coast Segment				
Segment information				
Revenue	26,868	21,320	73,310	62,958
Net operating margin	26,868	21,320	73,310	62,958
Facility expenses	9,798	8,785	27,100	23,875
Income from operations	17,070	12,535	46,210	39,083
Capital expenditures			1,282	3,418
Unallocated Segment				
Segment information				
Capital expenditures			$ 3,930	$ 3,268

Derivative Financial Instruments	9 Months Ended Sep. 30, 2011
Derivative Financial Instruments	
Derivative Financial Instruments	**5. Derivative Financial Instruments**

Commodity Derivatives

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

To mitigate its cash flow exposure to fluctuations in the price of NGLs, the Partnership has entered into derivative financial instruments relating to the future price of NGLs and crude oil. Generally the Partnership hedges its NGL price risk using crude oil as NGL financial markets are not as liquid and historically there has been a strong relationship between changes in NGL and crude oil prices. The pricing relationship between NGLs and crude oil may vary in certain periods due to various market conditions. In periods where NGL prices and crude oil prices are not consistent with the historical relationship, the Partnership incurs increased risk and additional gains or losses. The Partnership enters into NGL derivative contracts when adequate market liquidity exists.

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 and takes into account the partial offset of its long and short gas positions resulting from normal operating activities.

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

The Partnership enters into derivative contracts primarily with financial institutions that are participating members of the Credit Facility and collateral is not posted by the Partnership as the participating members have a collateral position in substantially all the wholly-owned assets of the Partnership. All of the Partnership' s financial derivative positions are currently with participating bank group members. Management conducts a standard credit review on counterparties and the Partnership has agreements containing collateral requirements. For all participating bank group members, collateral requirements do not exist when a derivative contract favors the Partnership. The Partnership uses standardized agreements that allow for offset of positive and negative exposures (master netting arrangements).

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

As of September 30, 2011, the Partnership had the following outstanding commodity contracts that were entered into to manage cash flow risk associated with future sales of NGLs or future purchases of natural gas.

Derivative contracts not designated as hedging instruments	Notional Quantity (net)
Crude oil (bbl)	6,843,759
Natural gas (MMBtu)	14,857,174
NGLs (gal)	138,213,006

Embedded Derivatives in Commodity Contracts

The Partnership has a commodity contract with a producer in the Appalachia region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. This contract is accounted for as an embedded derivative and is recorded at fair value. The changes in fair value of this commodity contract are based on the difference between the contractual and index pricing and are recorded in earnings through *Derivative (gain) loss related to purchased product costs*. In February 2011, the Partnership executed agreements with the producer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022. As of September 30, 2011, the estimated fair value of this contract was a liability of $94.7 million and the recorded value was a liability of $41.1 million. The recorded liability does not include the inception fair value of the commodity contract related to the extended period from April 1, 2015 to December 31, 2022. In accordance with GAAP for non-option embedded derivatives, the fair value of this extended portion of the commodity contract at its inception of February 1, 2011 is deemed to be allocable to the host processing contract and therefore not recorded as a derivative liability. See the following table for a reconciliation of the liability recorded for the embedded derivative as of September 30, 2011 (in thousands).

Fair value of commodity contract	$	94,652
Inception value for period from April 1, 2015 to December 31, 2022		(53,507)
Derivative liability as of September 30, 2011	$	41,145

The Partnership has a commodity contract that gives it an option to fix a component of the utilities cost to an index price on electricity at one of its plant locations through the fourth quarter of 2014. The value of the derivative component of this contract is marked to market through *Derivative gain related to facility expenses*. As of September 30, 2011, the estimated fair value of this contract was an asset of $3.9 million.

Financial Statement Impact of Derivative Instruments

There were no material changes to the Partnership' s policy regarding the accounting for these instruments as previously disclosed in the Partnership' s Annual Report on Form 10-K for the year ended December 31, 2010. The impact of the Partnership' s derivative instruments on its Condensed Consolidated Balance Sheets and its Condensed Consolidated Statements of Operations is summarized below (in thousands):

Derivative instruments not designated as hedging instruments and their balance sheet location	Assets				Liabilities			
	September 30, 2011		December 31, 2010		September 30, 2011		December 31, 2010	
Commodity contracts								
Fair value of derivative instruments - current	$	29,260	$	4,345	$	(65,499)	$	(65,489)
Fair value of derivative instruments - long-term		42,783		417		(34,161)		(66,290)
Total	$	72,043	$	4,762	$	(99,660)	$	(131,779)

Derivative instruments not designated as hedging instruments and the location of gain or (loss) recognized in income	Three months ended September 30,				Nine months ended September 30,			
	2011		2010		2011		2010	
Revenue: Derivative gain (loss)								
Realized loss	$	(9,809)	$	(1,732)	$	(36,386)	$	(20,551)
Unrealized gain (loss)		116,752		(35,227)		98,240		23,258
Total revenue: derivative gain (loss)		106,943		(36,959)		61,854		2,707

Derivative gain (loss) related to purchased product costs				
Realized loss	(5,989)	(3,946)	(19,436)	(15,117)
Unrealized gain (loss)	7,263	(16,050)	1,570	(9,876)
Total derivative gain (loss) related to purchased product costs	1,274	(19,996)	(17,866)	(24,993)
Derivative gain related to facility expenses				
Unrealized gain	2,787	564	2,871	436
Derivative gain related to interest expense				
Realized gain	–	–	–	2,380
Unrealized loss	–	–	–	(509)
Total derivative gain related to interest expense	–	–	–	1,871
Miscellaneous (expense) income, net				
Unrealized gain	–	103	–	162
Total gain (loss)	$ 111,004	$ (56,288)	$ 46,859	$ (19,817)

At September 30, 2011, the fair value of the Partnership' s commodity derivative contracts is inclusive of premium payments of $1.2 million, net of amortization. For the three months ended September 30, 2011 and 2010, the *Realized loss¬revenue* includes amortization of premium payments of $1.2 million and $0.5 million, respectively. For the nine months ended September 30, 2011 and 2010, the *Realized loss¬revenue* includes amortization of premium payments of $3.3 million and $1.6 million, respectively.

Fair Value (Details 2) (USD $) In Thousands	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Commodity contracts (net)				
Derivative assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy				
Fair value at beginning of period	$ (22,290)	$ 5,348	$ (14,357)	$ (11,340)
Total gain or (loss) (realized and unrealized) included in earnings	47,939	(8,952)	35,402	1,319
Settlements	3,167	65	7,771	6,482
Fair value at end of period	28,816	(3,539)	28,816	(3,539)
The amount of total gain or (loss) for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period	48,544	(8,592)	39,196	(2,712)
Embedded derivatives in commodity contracts (net)				
Derivative assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy				
Fair value at beginning of period	(49,447)	(23,636)	(34,936)	(34,199)
Total gain or (loss) (realized and unrealized) included in earnings	8,042	(11,977)	(14,063)	(6,857)
Settlements	4,167	2,298	11,761	7,741
Fair value at end of period	(37,238)	(33,315)	(37,238)	(33,315)
The amount of total gain or (loss) for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period	8,337	(11,345)	(10,813)	(4,703)
Interest rate contracts				
Derivative assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy				
Fair value at beginning of period				509
Total gain or (loss) (realized and unrealized) included in earnings				1,871
Settlements				(2,380)
Embedded derivative in debt contract				
Derivative assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy				
Fair value at beginning of period		(131)		(190)
Total gain or (loss) (realized and unrealized) included in earnings		103		162
Fair value at end of period		(28)		(28)
The amount of total gain or (loss) for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period		$ 103		$ 162

Inventories (Tables)	9 Months Ended Sep. 30, 2011

Inventories

Components of inventory

	September 30, 2011	December 31, 2010
NGLs	$ 35,567	$ 15,930
Spare parts, materials and supplies	7,814	7,502
Total inventories	$ 43,381	$ 23,432

Income Taxes (Tables)

	9 Months Ended Sep. 30, 2011

Income Taxes

Reconciliation of the provision for income tax to the amount computed by applying the federal statutory rate

	Nine months ended September 30, 2011			
	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$ 31,993	$ 166,649	$ (4,212)	$ 194,430
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ 11,198	$ –	$ –	$ 11,198
Permanent items	22	–	–	22
State income taxes net of federal benefit	889	848	–	1,737
Provision on income from Class A units (1)	13,359	–	–	13,359
Other	126	–	–	126
Provision for income tax	$ 25,594	$ 848	$ –	$ 26,442

	Nine months ended September 30, 2010			
	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$ 5,303	$ 83,603	$ (4,401)	$ 84,505
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ 1,856	$ –	$ –	$ 1,856
Permanent items	6	–	–	6
State income taxes net of federal benefit	190	474	–	664
Provision on income from Class A units (1)	8,251	–	–	8,251
Other	(568)	–	–	(568)
Provision for income tax	$ 9,735	$ 474	$ –	$ 10,209

(1) The Corporation and the General Partner of the Partnership own Class A units of the Partnership that were received in the merger of the Corporation and the Partnership completed in February 2008. For further discussion of Class A units, see Item 1. *Business* in the Partnership' s Annual Report on Form 10-K for the year ended December 31, 2010.

Fair Value (Details) (USD $) In Thousands	Sep. 30, 2011	Dec. 31, 2010
Derivative instruments carried at fair value in Condensed Consolidated Balance Sheet		
Total carrying value of derivative assets in Condensed Consolidated Balance Sheet	$ 72,043	$ 4,762
Total carrying value of derivative liabilities in Condensed Consolidated Balance Sheet	(99,660)	(131,779)
Commodity contracts (net) | Recurring | Significant other observable inputs (Level 2)		
Derivative instruments carried at fair value in Condensed Consolidated Balance Sheet		
Total carrying value of derivative assets in Condensed Consolidated Balance Sheet	34,678	52
Total carrying value of derivative liabilities in Condensed Consolidated Balance Sheet	(53,873)	(77,776)
Commodity contracts (net) | Recurring | Significant unobservable inputs (Level 3)		
Derivative instruments carried at fair value in Condensed Consolidated Balance Sheet		
Total carrying value of derivative assets in Condensed Consolidated Balance Sheet	33,458	3,674
Total carrying value of derivative liabilities in Condensed Consolidated Balance Sheet	(4,642)	(18,031)
Recurring | Significant unobservable inputs (Level 3) | Embedded derivatives in commodity contracts (net)		
Derivative instruments carried at fair value in Condensed Consolidated Balance Sheet		
Total carrying value of derivative assets in Condensed Consolidated Balance Sheet	3,907	1,036
Total carrying value of derivative liabilities in Condensed Consolidated Balance Sheet	$ (41,145)	$ (35,972)

Long-Term Debt (Tables)

9 Months Ended Sep. 30, 2011

Long-Term Debt

Summary of debt

	September 30, 2011	December 31, 2010
Credit Facility		
Revolving credit facility, 4.25% interest due September 2016	$ 145,100	$ –
Senior Notes (1)		
Senior Notes, 8.5% interest, net of discount of $0 and $642, respectively, issued July 2006 and due July 2016	–	274,358
Senior Notes, 8.75% interest, net of discount of $555 and $924, respectively, issued April and May 2008 and due April 2018	333,807	499,076
Senior Notes, 6.75% interest, issued November 2010 and due November 2020	500,000	500,000
Senior Notes, 6.5% interest, net of discount of $944, issued February and March 2011 and due August 2021	499,056	–
Total long-term debt	$ 1,477,963	$ 1,273,434

(1) The estimated aggregate fair value of the senior notes (collectively, the “Senior Notes”) was approximately $1,350.2 million and $1,333.9 million as of September 30, 2011 and December 31, 2010, respectively, based on quoted market prices.

Income Taxes	9 Months Ended Sep. 30, 2011

[**Income Taxes**]

[Income Taxes]

13. Income Taxes

A reconciliation of the provision for income tax and the amount computed by applying the federal statutory rate to income before provision for income tax for the nine months ended September 30, 2011 and 2010 is as follows (in thousands):

	Nine months ended September 30, 2011			
	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$ 31,993	$ 166,649	$ (4,212)	$ 194,430
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ 11,198	$ –	$ –	$ 11,198
Permanent items	22	–	–	22
State income taxes net of federal benefit	889	848	–	1,737
Provision on income from Class A units (1)	13,359	–	–	13,359
Other	126	–	–	126
Provision for income tax	$ 25,594	$ 848	$ –	$ 26,442

	Nine months ended September 30, 2010			
	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$ 5,303	$ 83,603	$ (4,401)	$ 84,505
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ 1,856	$ –	$ –	$ 1,856
Permanent items	6	–	–	6
State income taxes net of federal benefit	190	474	–	664
Provision on income from Class A units (1)	8,251	–	–	8,251
Other	(568)	–	–	(568)
Provision for income tax	$ 9,735	$ 474	$ –	$ 10,209

(1) The Corporation and the General Partner of the Partnership own Class A units of the Partnership that were received in the merger of the Corporation and the Partnership completed in February 2008. For further discussion of Class A units, see Item 1. *Business* in the Partnership' s Annual Report on Form 10-K for the year ended December 31, 2010.

Supplemental Condensed Consolidating Financial Information (Details 3) (USD $) In Thousands	9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010
Condensed Consolidating Statements of Cash Flows		
Net cash (used in) provided by operating activities	$ 331,249	$ 197,238
Cash flows from investing activities:		
Capital expenditures	(359,926)	(374,173)
Acquisitions	(230,728)	
Proceeds from disposal of property, plant and equipment	2,968	524
Net cash used in investing activities	(587,686)	(373,649)
Cash flows from financing activities:		
Proceeds from revolving credit facility	1,074,700	421,304
Payments of revolving credit facility	(929,600)	(378,804)
Proceeds from long-term debt	499,000	
Payments of long-term debt	(440,638)	
Payments of premiums on redemption of long-term debt	(39,642)	
Payments for debt issuance costs, deferred financing costs and registration costs	(7,795)	(11,230)
Contributions to joint ventures, net	80,332	148,057
Payments of SMR liability	(1,390)	(912)
Proceeds from public equity offering, net	323,492	142,255
Share-based payment activity	(5,265)	(3,737)
Payment of distributions	(205,030)	(139,779)
Net cash provided by financing activities	348,164	177,154
Net increase in cash	91,727	743
Cash and cash equivalents at beginning of year	67,450	97,752
Cash and cash equivalents at end of period	159,177	98,495
Parent		
Condensed Consolidating Statements of Cash Flows		
Net cash (used in) provided by operating activities	(89,044)	(63,740)
Cash flows from investing activities:		
Capital expenditures	(785)	(569)
Equity investments	(34,246)	(32,442)
Distributions from consolidated affiliates	37,978	33,237
Investment in/ Payment for intercompany notes, net	(17,600)	(1,550)
Net cash used in investing activities	(14,653)	(1,324)
Cash flows from financing activities:		
Proceeds from revolving credit facility	1,074,700	421,304
Payments of revolving credit facility	(929,600)	(378,804)
Proceeds from long-term debt	499,000	
Payments of long-term debt	(440,638)	
Payments of premiums on redemption of long-term debt	(39,642)	
Payments for debt issuance costs, deferred financing costs and registration costs	(7,795)	(11,230)

Proceeds from public equity offering, net	323,492	142,255
Share-based payment activity	(6,354)	(3,834)
Payment of distributions	(155,931)	(134,949)
Intercompany advances, net	(213,532)	30,322
Net cash provided by financing activities	103,700	65,064
Net increase in cash	3	
Cash and cash equivalents at end of period	3	
Guarantor Subsidiaries		
Condensed Consolidating Statements of Cash Flows		
Net cash (used in) provided by operating activities	303,401	230,279
Cash flows from investing activities:		
Capital expenditures	(100,155)	(97,039)
Acquisitions	(230,728)	
Equity investments	(204,428)	(130,074)
Distributions from consolidated affiliates	50,019	14,512
Proceeds from disposal of property, plant and equipment	365	524
Net cash used in investing activities	(484,927)	(212,077)
Cash flows from financing activities:		
(Payments of) proceeds from intercompany notes, net	(5,400)	1,550
Contributions to guarantor subsidiaries, net	34,246	32,442
Payments of SMR liability	(1,390)	(912)
Share-based payment activity	1,089	97
Payment of distributions	(37,978)	(33,237)
Intercompany advances, net	213,532	(30,322)
Net cash provided by financing activities	204,099	(30,382)
Net increase in cash	22,573	(12,180)
Cash and cash equivalents at beginning of year	63,850	74,448
Cash and cash equivalents at end of period	86,423	62,268
Non-Guarantor Subsidiaries		
Condensed Consolidating Statements of Cash Flows		
Net cash (used in) provided by operating activities	121,551	35,460
Cash flows from investing activities:		
Capital expenditures	(264,996)	(281,326)
Proceeds from disposal of property, plant and equipment	3,954	
Net cash used in investing activities	(261,042)	(281,326)
Cash flows from financing activities:		
(Payments of) proceeds from intercompany notes, net	23,000	
Contributions to joint ventures, net	284,760	278,131
Payment of distributions	(99,118)	(19,342)
Net cash provided by financing activities	208,642	258,789
Net increase in cash	69,151	12,923
Cash and cash equivalents at beginning of year	3,600	23,304
Cash and cash equivalents at end of period	72,751	36,227
Consolidating Adjustments		

Condensed Consolidating Statements of Cash Flows		
Net cash (used in) provided by operating activities	(4,659)	(4,761)
Cash flows from investing activities:		
Capital expenditures	6,010	4,761
Equity investments	238,674	162,516
Distributions from consolidated affiliates	(87,997)	(47,749)
Investment in/ Payment for intercompany notes, net	17,600	1,550
Proceeds from disposal of property, plant and equipment	(1,351)	
Net cash used in investing activities	172,936	121,078
Cash flows from financing activities:		
(Payments of) proceeds from intercompany notes, net	(17,600)	(1,550)
Contributions to guarantor subsidiaries, net	(34,246)	(32,442)
Contributions to joint ventures, net	(204,428)	(130,074)
Payment of distributions	87,997	47,749
Net cash provided by financing activities	$ (168,277)	$ (116,317)

Fair Value	9 Months Ended Sep. 30, 2011

Fair Value

Fair Value

6. Fair Value

Fair value measurements and disclosures relate primarily to the Partnership' s derivative positions discussed in Note 5. The following table presents the derivative instruments carried at fair value as of September 30, 2011 and December 31, 2010 (in thousands):

As of September 30, 2011	Assets	Liabilities
Significant other observable inputs (Level 2)		
Commodity contracts	$34,678	$(53,873)
Significant unobservable inputs (Level 3)		
Commodity contracts	33,458	(4,642)
Embedded derivatives in commodity contracts	3,907	(41,145)
Total carrying value in Condensed Consolidated Balance Sheet	$72,043	$(99,660)

As of December 31, 2010	Assets	Liabilities
Significant other observable inputs (Level 2)		
Commodity contracts	$ 52	$ (77,776)
Significant unobservable inputs (Level 3)		
Commodity contracts	3,674	(18,031)
Embedded derivatives in commodity contracts	1,036	(35,972)
Total carrying value in Condensed Consolidated Balance Sheet	$ 4,762	$(131,779)

Changes in Level 3 Fair Value Measurements

The table below includes a rollforward of the balance sheet amounts for the three and nine months ended September 30, 2011 and 2010 for assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy (in thousands).

	Three months ended September 30, 2011	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	$ (22,290)	$ (49,447)
Total gain (realized and unrealized) included in earnings (1)	47,939	8,042
Settlements	3,167	4,167
Fair value at end of period	$ 28,816	$ (37,238)

The amount of total gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ 48,544	$ 8,337

	Three months ended September 30, 2010		
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Embedded Derivative in Debt Contract
Fair value at beginning of period	$ 5,348	$ (23,636)	$ (131)
Total (loss) or gain (realized and unrealized) included in earnings (1)	(8,952)	(11,977)	103
Settlements (net)	65	2,298	–
Fair value at end of period	$ (3,539)	$ (33,315)	$ (28)
The amount of total (loss) or gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ (8,592)	$ (11,345)	$ 103

	Nine months ended September 30, 2011	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	$ (14,357)	$ (34,936)
Total gain or (loss) (realized and unrealized) included in earnings (1)	35,402	(14,063)
Settlements	7,771	11,761
Fair value at end of period	$ 28,816	$ (37,238)
The amount of total gain or (loss) for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ 39,196	$ (10,813)

	Nine months ended September 30, 2010			
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Interest Rate Contracts	Embedded Derivative in Debt Contract
Fair value at beginning of period	$ (11,340)	$ (34,199)	$ 509	$ (190)
Total gain or (loss) (realized and unrealized) included in earnings (1)	1,319	(6,857)	1,871	162
Settlements (net)	6,482	7,741	(2,380)	–
Fair value at end of period	$ (3,539)	$ (33,315)	$ –	$ (28)

The amount of total (loss) or gain for the period included in earnings attributable to the change in unrealized gains or losses relating to contracts still held at end of period (1)	$ (2,712)	$ (4,703)	$ –	$ 162

(1) Gains and losses on Commodity Derivative Contracts classified as Level 3 are recorded in *Derivative gain (loss) related to revenue*. Gains and losses on Embedded Derivatives in Commodity Contracts are recorded in *Purchased product costs, Derivative (gain) loss related to purchased product costs and Derivative gain related to facility expenses*. Gains on Embedded Derivatives in Debt Contract are recorded in *Miscellaneous (expense) income, net.* Gains on Interest Rate Contracts are recorded in *Derivative gain related to interest expense*.

Supplemental Condensed Consolidating Financial Information	9 Months Ended
	Sep. 30, 2011

Supplemental Condensed Consolidating Financial Information
Supplemental Condensed Consolidating Financial Information

16. Supplemental Condensed Consolidating Financial Information

The Partnership has no operations independent of its subsidiaries. As of September 30, 2011, the Partnership' s obligations under the outstanding Senior Notes (see Note 9) were fully and unconditionally guaranteed, jointly and severally, by all of its wholly-owned subsidiaries. MarkWest Liberty Midstream and MarkWest Pioneer, together with certain of the Partnership' s other subsidiaries that do not guarantee the outstanding Senior Notes, have significant assets and operations in aggregate. For the purpose of the following financial information, the Partnership' s investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities. The operations, cash flows and financial position of the co-issuer of the Senior Notes, MarkWest Energy Finance Corporation, are minor and therefore have been included with the Parent' s financial information. Condensed consolidating financial information for the Partnership, its combined guarantor and combined non-guarantor subsidiaries as of September 30, 2011 and December 31, 2010 and for the three and nine months ended September 30, 2011 and 2010 is as follows (in thousands):

Condensed Consolidating Balance Sheets

	As of September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 3	$ 86,423	$ 72,751	$ –	$ 159,177
Restricted cash	–	–	25,143	–	25,143
Receivables and other current assets	846	222,835	36,806	–	260,487
Intercompany receivables	9,548	8,668	24,505	(42,721)	–
Fair value of derivative instruments	–	28,980	280	–	29,260
Total current assets	10,397	346,906	159,485	(42,721)	474,067
Total property, plant and equipment, net	4,191	1,681,413	1,049,629	(15,415)	2,719,818
Other long-term assets:					
Restricted cash	–	–	3,007	–	3,007
Investment in unconsolidated affiliate	–	27,126	–	–	27,126

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Investment in consolidated affiliates	2,659,809	554,896	−	(3,214,705)	−
Intangibles, net of accumulated amortization	−	614,201	551	−	614,752
Fair value of derivative instruments	−	42,783	−	−	42,783
Intercompany notes receivable	215,310	−	−	(215,310)	−
Other long-term assets	33,733	70,554	361	−	104,648
Total assets	$2,923,440	$ 3,337,879	$1,213,033	$(3,488,151)	$3,986,201
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 8,568	$ 33,807	$ 346	$ (42,721)	$ −
Fair value of derivative instruments	−	65,499	−	−	65,499
Other current liabilities	37,409	209,828	104,637	−	351,874
Total current liabilities	45,977	309,134	104,983	(42,721)	417,373
Deferred income taxes	1,623	27,142	−	−	28,765
Intercompany notes payable	−	192,310	23,000	(215,310)	−
Fair value of derivative instruments	−	34,161	−	−	34,161
Long-term debt, net of discounts	1,477,963	−	−	−	1,477,963
Other long-term liabilities	3,316	115,323	196	−	118,835
Equity:					
MarkWest Energy Partners, L.P. partners' capital	1,394,561	2,659,809	1,084,854	(3,760,078)	1,379,146
Non-controlling interest in consolidated subsidiaries	−	−	−	529,958	529,958
Total equity	1,394,561	2,659,809	1,084,854	(3,230,120)	1,909,104
Total liabilities and equity	$2,923,440	$ 3,337,879	$1,213,033	$(3,488,151)	$3,986,201

	As of December 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ −	$ 63,850	$ 3,600	$ −	$ 67,450

Receivables and other current assets	1,708	172,209	52,834	–	226,751
Intercompany receivables	1,440,302	1,099	7,635	(1,449,036)	–
Fair value of derivative instruments	–	4,345	–	–	4,345
Total current assets	1,442,010	241,503	64,069	(1,449,036)	298,546
Total property, plant and equipment, net	4,623	1,512,763	812,898	(11,260)	2,319,024
Other long-term assets:					
Restricted cash	–	–	28,001	–	28,001
Investment in unconsolidated affiliate	–	28,688	–	–	28,688
Investment in consolidated affiliates	716,673	368,864	–	(1,085,537)	–
Intangibles, net of accumulated amortization	–	613,000	578	–	613,578
Fair value of derivative instruments	–	417	–	–	417
Intercompany notes receivable	197,710	–	–	(197,710)	–
Other long-term assets	32,587	12,139	382	–	45,108
Total assets	$2,393,603	$ 2,777,374	$ 905,928	$(2,743,543)	$3,333,362
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 672	$ 1,447,799	$ 565	$(1,449,036)	$ –
Fair value of derivative instruments	–	65,489	–	–	65,489
Other current liabilities	31,882	173,667	70,804	–	276,353
Total current liabilities	32,554	1,686,955	71,369	(1,449,036)	341,842
Deferred income taxes	2,533	7,894	–	–	10,427
Intercompany notes payable	–	197,710	–	(197,710)	–
Fair value of derivative instruments	–	66,290	–	–	66,290
Long-term debt, net of discounts	1,273,434	–	–	–	1,273,434
Other long-term liabilities	3,319	101,852	178	–	105,349
Equity:					

MarkWest Energy Partners, L.P. partners' capital	1,081,763	716,673	834,381	(1,562,314)	1,070,503
Non-controlling interest in consolidated subsidiaries	–	–	–	465,517	465,517
Total equity	1,081,763	716,673	834,381	(1,096,797)	1,536,020
Total liabilities and equity	$2,393,603	$ 2,777,374	$ 905,928	$(2,743,543)	$3,333,362

Condensed Consolidating Statements of Operations

	Three Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 425,142	$ 82,684	$ –	$ 507,826
Operating expenses:					
Purchased product costs	–	155,612	32,398	–	188,010
Facility expenses	–	31,351	10,263	(165)	41,449
Selling, general and administrative expenses	11,270	7,768	2,421	(1,297)	20,162
Depreciation and amortization	182	38,391	11,314	(187)	49,700
Other operating expenses	–	1,069	(365)	–	704
Total operating expenses	11,452	234,191	56,031	(1,649)	300,025
(Loss) income from operations	(11,452)	190,951	26,653	1,649	207,801
Earnings from consolidated affiliates	174,458	13,479	–	(187,937)	–
Loss on redemption of debt	(133)	–	–	–	(133)
Other expense, net	(20,609)	(4,849)	(32)	(2,860)	(28,350)
Income before provision for income tax	142,264	199,581	26,621	(189,148)	179,318
Provision for income tax expense	741	25,123	–	–	25,864
Net income	141,523	174,458	26,621	(189,148)	153,454
Net income attributable to non-controlling interest	–	–	–	(13,142)	(13,142)
Net income attributable to the Partnership	$141,523	$ 174,458	$ 26,621	$ (202,290)	$ 140,312

	Three Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 222,004	$ 33,407	$ –	$ 255,411

Operating expenses:					
Purchased product costs	–	150,689	6,007	–	156,696
Facility expenses	–	30,931	6,602	(163)	37,370
Selling, general and administrative expenses	12,203	4,842	1,354	(1,262)	17,137
Depreciation and amortization	147	34,400	7,117	(109)	41,555
Other operating expenses	730	1,269	8	–	2,007
Total operating expenses	13,080	222,131	21,088	(1,534)	254,765
(Loss) income from operations	(13,080)	(127)	12,319	1,534	646
Earnings from consolidated affiliates	9,249	4,256	–	(13,505)	–
Other (expense) income, net	(21,539)	(5,097)	412	(3,336)	(29,560)
(Loss) income before provision for income tax	(25,370)	(968)	12,731	(15,307)	(28,914)
Provision for income tax benefit	(21)	(10,217)	–	–	(10,238)
Net (loss) income	(25,349)	9,249	12,731	(15,307)	(18,676)
Net income attributable to non-controlling interest	–	–	–	(8,475)	(8,475)
Net (loss) income attributable to the Partnership	$(25,349)	$ 9,249	$ 12,731	$ (23,782)	$ (27,151)

	Nine Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 991,993	$ 179,493	$ –	$1,171,486
Operating expenses:					
Purchased product costs	–	463,459	51,900	–	515,359
Facility expenses	–	95,701	26,285	(499)	121,487
Selling, general and administrative expenses	35,348	23,139	6,390	(4,423)	60,454
Depreciation and amortization	538	112,868	30,010	(504)	142,912
Other operating expenses	673	4,895	(15)	–	5,553
Total operating expenses	36,559	700,062	114,570	(5,426)	845,765
(Loss) income from operations	(36,559)	291,931	64,923	5,426	325,721
Earnings from consolidated affiliates	287,377	31,623	–	(319,000)	–

Loss on redemption of debt	(43,461)	–	–	–	(43,461)
Other expense, net	(67,574)	(10,583)	(92)	(9,581)	(87,830)
Income before provision for income tax	139,783	312,971	64,831	(323,155)	194,430
Provision for income tax expense	848	25,594	–	–	26,442
Net income	138,935	287,377	64,831	(323,155)	167,988
Net income attributable to non-controlling interest	–	–	–	(33,208)	(33,208)
Net income attributable to the Partnership	$138,935	$ 287,377	$ 64,831	$ (356,363)	$ 134,780

	Nine Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 807,585	$ 80,055	$ –	$ 887,640
Operating expenses:					
Purchased product costs	–	425,469	8,643	–	434,112
Facility expenses	–	91,074	22,245	(489)	112,830
Selling, general and administrative expenses	35,243	19,370	4,141	(3,690)	55,064
Depreciation and amortization	438	101,034	18,739	(265)	119,946
Other operating expenses	730	1,364	304	–	2,398
Total operating expenses	36,411	638,311	54,072	(4,444)	724,350
(Loss) income from operations	(36,411)	169,274	25,983	4,444	163,290
Earnings from consolidated affiliates	156,634	7,521	–	(164,155)	–
Other (expense) income, net	(60,675)	(10,427)	1,258	(8,941)	(78,785)
Income before provision for income tax	59,548	166,368	27,241	(168,652)	84,505
Provision for income tax expense	475	9,734	–	–	10,209
Net income	59,073	156,634	27,241	(168,652)	74,296
Net income attributable to non-controlling interest	–	–	–	(19,720)	(19,720)
Net income attributable to the Partnership	$59,073	$ 156,634	$ 27,241	$ (188,372)	$ 54,576

Condensed Consolidating Statements of Cash Flows

Nine Months Ended September 30, 2011

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$ (89,044)	$ 303,401	$ 121,551	$ (4,659)	$ 331,249
Cash flows from investing activities:					
Capital expenditures	(785)	(100,155)	(264,996)	6,010	(359,926)
Acquisitions	–	(230,728)	–	–	(230,728)
Equity investments	(34,246)	(204,428)	–	238,674	–
Distributions from consolidated affiliates	37,978	50,019	–	(87,997)	–
Investment in intercompany notes, net	(17,600)	–	–	17,600	–
Proceeds from disposal of property, plant and equipment	–	365	3,954	(1,351)	2,968
Net cash used in investing activities	(14,653)	(484,927)	(261,042)	172,936	(587,686)
Cash flows from financing activities:					
Proceeds from revolving credit facility	1,074,700	–	–	–	1,074,700
Payments of revolving credit facility	(929,600)	–	–	–	(929,600)
Proceeds from long-term debt	499,000	–	–	–	499,000
Payments of long-term debt	(440,638)	–	–	–	(440,638)
Payments of premiums on redemption of long-term debt	(39,642)	–	–	–	(39,642)
(Payments of) proceeds from intercompany notes, net	–	(5,400)	23,000	(17,600)	–
Payments for debt issuance costs, deferred financing costs and registration costs	(7,795)	–	–	–	(7,795)
Contributions to guarantor subsidiaries, net	–	34,246	–	(34,246)	–
Contributions to joint ventures, net	–	–	284,760	(204,428)	80,332
Payments of SMR liability	–	(1,390)	–	–	(1,390)
Proceeds from public equity offering, net	323,492	–	–	–	323,492
Share-based payment activity	(6,354)	1,089	–	–	(5,265)
Payment of distributions	(155,931)	(37,978)	(99,118)	87,997	(205,030)
Intercompany advances, net	(213,532)	213,532			
Net cash provided by financing activities	103,700	204,099	208,642	(168,277)	348,164
Net increase in cash	3	22,573	69,151	–	91,727
Cash and cash equivalents at beginning of year	–	63,850	3,600	–	67,450
Cash and cash equivalents at end of period	$ 3	$ 86,423	$ 72,751	$ –	$ 159,177

Nine Months Ended September 30, 2010

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$ (63,740)	$ 230,279	$ 35,460	$ (4,761)	$ 197,238
Cash flows from investing activities:					
Capital expenditures	(569)	(97,039)	(281,326)	4,761	(374,173)
Equity investments	(32,442)	(130,074)	–	162,516	–
Distributions from consolidated affiliates	33,237	14,512	–	(47,749)	–
Payments for intercompany notes, net	(1,550)	–	–	1,550	–
Proceeds from disposal of property, plant and equipment	–	524	–	–	524
Net cash used in investing activities	(1,324)	(212,077)	(281,326)	121,078	(373,649)
Cash flows from financing activities:					
Proceeds from revolving credit facility	421,304	–	–	–	421,304
Payments of revolving credit facility	(378,804)	–	–	–	(378,804)
Proceeds from intercompany notes, net	–	1,550	–	(1,550)	–
Payments for debt issuance costs, deferred financing costs and registration costs	(11,230)	–	–	–	(11,230)
Contributions from parent, net	–	32,442	–	(32,442)	–
Contributions to joint ventures, net	–	–	278,131	(130,074)	148,057
Payments of SMR liability	–	(912)	–	–	(912)
Proceeds from public offering, net	142,255	–	–	–	142,255
Share-based payment activity	(3,834)	97	–	–	(3,737)
Payment of distributions	(134,949)	(33,237)	(19,342)	47,749	(139,779)
Intercompany advances, net	30,322	(30,322)	–	–	–
Net cash provided by (used in) financing activities	65,064	(30,382)	258,789	(116,317)	177,154
Net (decrease) increase in cash	–	(12,180)	12,923	–	743
Cash and cash equivalents at beginning of year	–	74,448	23,304	–	97,752
Cash and cash equivalents at end of period	$ –	$ 62,268	$ 36,227	$ –	$ 98,495

Variable Interest Entities (Details) (USD $)	Sep. 30, 2011	Dec. 31, 2010	Sep. 30, 2010	Dec. 31, 2009	Sep. 30, 2011 Total Variable Interest Entity	Dec. 31, 2010 Total Variable Interest Entity	9 Months Ended Sep. 30, 2011 MarkWest Liberty Midstream	Dec. 31, 2010 MarkWest Liberty Midstream	Sep. 30, 2011 MarkWest Pioneer	Dec. 31, 2010 MarkWest Pioneer
Variable interest entities										
Percentage of ownership interest (as a percent)							51.00%			
Percentage of ownership interest held by M & R MWE Liberty, LLC (as a percent)							49.00%			
Special allocation of net income received by M & R							$ 1,300,000			
ASSETS										
Cash and cash equivalents	159,177,000	67,450,000	98,495,000	97,752,000	72,171,000	2,913,000	69,808,000		2,363,000	2,913,000
Restricted cash (current)	25,143,000	0			25,143,000	0	25,143,000			
Receivables, net	192,271,000	179,209,000			13,451,000	43,783,000	12,116,000	42,181,000	1,335,000	1,602,000
Inventories	43,381,000	23,432,000			21,919,000	8,431,000	21,919,000	8,431,000		
Fair value of derivative instruments - current assets	29,260,000	4,345,000			280,000	0	280,000			
Other current assets	8,745,000	8,020,000			1,168,000	272,000	1,168,000	271,000		1,000
Property, plant and equipment, net	2,719,818,000	2,319,024,000			1,048,657,000	811,817,000	906,199,000	664,778,000	142,458,000	147,039,000
Accumulated depreciation	401,729,000	294,003,000			67,455,000	38,169,000	53,468,000	28,869,000	13,987,000	9,300,000
Restricted cash (long-term)	3,007,000	28,001,000			3,007,000	28,001,000	3,007,000	28,001,000		
Other long-term assets	1,621,000	1,486,000			361,000	383,000	259,000	281,000	102,000	102,000
Total assets	3,986,201,000	3,333,362,000			1,186,157,000	895,600,000	1,039,899,000	743,943,000	146,258,000	151,657,000
LIABILITIES										
Accounts payable	183,695,000	122,473,000			35,724,000	5,945,000	35,644,000	5,945,000	80,000	
Accrued liabilities	168,168,000	153,869,000			68,781,000	64,713,000	67,849,000	63,450,000	932,000	1,263,000
Other long-term liabilities	118,835,000	105,349,000			163,000	154,000	91,000	86,000	72,000	68,000
Total liabilities					$ 104,668,000	$ 70,812,000	$ 103,584,000	$ 69,481,000	$ 1,084,000	$ 1,331,000

Goodwill (Tables)

9 Months Ended Sep. 30, 2011

Goodwill.

Schedule of changes in goodwill

	Southwest	Northeast	Gulf Coast	Total
Gross goodwill as of December 31, 2010	$ 24,324	$ 3,948	$ 9,854	$ 38,126
Acquisition(1)	–	58,497	–	58,497
Gross Goodwill as of September 30, 2011	24,324	62,445	9,854	96,623
Cumulative impairment (2)	(18,851)	–	(9,854)	(28,705)
Balance as of September 30, 2011	$ 5,473	$ 62,445	$ –	$ 67,918

(1) Represents goodwill associated with the Langley Acquisition (see Note 3).
(2) All impairments recorded in the fourth quarter of 2008.

Condensed Consolidated Statements of Cash Flows (USD $) In Thousands	9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010
Cash flows from operating activities:		
Net income	$ 167,988	$ 74,296
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	110,280	89,367
Amortization of intangible assets	32,632	30,579
Loss on redemption of debt	43,461	
Amortization of deferred financing costs and discount	3,873	8,517
Accretion of asset retirement obligations	934	282
Amortization of deferred contract cost	234	234
Phantom unit compensation expense	10,611	11,430
Loss (earnings) of unconsolidated affiliate	1,262	(1,517)
Distribution from unconsolidated affiliate	300	2,508
Unrealized gain on derivative instruments	(99,400)	(11,885)
Loss on disposal of property, plant and equipment	4,619	2,116
Deferred income taxes	18,338	(45)
Changes in operating assets and liabilities, net of working capital acquired:		
Receivables	(12,776)	(35,072)
Inventories	(19,470)	576
Other current assets	(725)	2,026
Accounts payable and accrued liabilities	56,716	23,042
Other long-term assets	(284)	(509)
Other long-term liabilities	12,656	1,293
Net cash provided by operating activities	331,249	197,238
Cash flows from investing activities:		
Capital expenditures	(359,926)	(374,173)
Acquisitions	(230,728)	
Proceeds from disposal of property, plant and equipment	2,968	524
Net cash used in investing activities	(587,686)	(373,649)
Cash flows from financing activities:		
Proceeds from revolving credit facility	1,074,700	421,304
Payments of revolving credit facility	(929,600)	(378,804)
Proceeds from long-term debt	499,000	
Payments of long-term debt	(440,638)	
Payments of premiums on redemption of long-term debt	(39,642)	
Payments for debt issuance costs, deferred financing costs and registration costs	(7,795)	(11,230)
Contributions to MarkWest Liberty Midstream joint venture	80,332	148,057
Payments of SMR liability	(1,390)	(912)
Proceeds from public offerings, net	323,492	142,255
Cash paid for taxes related to net settlement of share-based payment awards	(6,354)	(3,834)

Excess tax benefits related to share-based compensation	1,089	97
Payment of distributions to common unitholders	(155,931)	(134,949)
Payment of distributions to non-controlling interest	(49,099)	(4,830)
Net cash provided by financing activities	348,164	177,154
Net increase in cash	91,727	743
Cash and cash equivalents at beginning of year	67,450	97,752
Cash and cash equivalents at end of period	$ 159,177	$ 98,495

Supplemental Cash Flow Information	9 Months Ended Sep. 30, 2011

[Supplemental Cash Flow Information](#)

[Supplemental Cash Flow Information](#)

17. Supplemental Cash Flow Information

The following table provides information regarding supplemental cash flow information (in thousands).

	Nine months ended September 30,	
	2011	2010
Supplemental disclosures of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ 76,876	$ 64,448
Cash paid for income taxes, net of refunds	5,051	8,760
Supplemental schedule of non-cash investing and financing activities:		
Accrued property, plant and equipment	$ 85,666	$ 53,381
Interest capitalized on construction in progress	571	2,719
Issuance of common units for vesting of share-based payment awards	5,412	7,238

Goodwill (Details) (USD $) In Thousands	9 Months Ended Sep. 30, 2011	Dec. 31, 2010
Changes in goodwill		
Gross goodwill at the beginning of the period	$ 38,126	
Acquisition	58,497	
Gross Goodwill at ending of the period	96,623	
Cumulative impairment	(28,705)	(28,705)
Balance at the end of the period	67,918	9,421
Southwest Segment		
Changes in goodwill		
Gross goodwill at the beginning of the period		24,324
Gross Goodwill at ending of the period	24,324	24,324
Cumulative impairment	(18,851)	(18,851)
Balance at the end of the period	5,473	
Northeast Segment		
Changes in goodwill		
Gross goodwill at the beginning of the period	3,948	
Acquisition	58,497	
Gross Goodwill at ending of the period	62,445	
Balance at the end of the period	62,445	
Gulf Coast Segment		
Changes in goodwill		
Gross goodwill at the beginning of the period		9,854
Gross Goodwill at ending of the period	9,854	9,854
Cumulative impairment	$ (9,854)	$ (9,854)

Business Combination (Tables)	9 Months Ended Sep. 30, 2011
Business Combination	
Schedule of purchase price allocation	

Property, plant and equipment	$	136,525
Goodwill		58,497
Intangibles		33,900
Inventories		1,806
Total	$	230,728

Recent Accounting Pronouncements	9 Months Ended Sep. 30, 2011

Recent Accounting Pronouncements

Recent Accounting Pronouncements

2. Recent Accounting Pronouncements

In September 2009, the FASB amended the accounting guidance for revenue recognition for multiple-deliverable arrangements. The amended guidance establishes a hierarchy for determining the selling price of each individual deliverable and eliminates the residual value method of allocating the selling price. The amended guidance was effective for the Partnership prospectively for all revenue arrangements entered into or materially modified on or after January 1, 2011. The amendment did not have a material effect on the Partnership' s condensed consolidated financial statements.

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

In September 2011, the FASB amended the accounting guidance for goodwill impairment testing. The amended guidance provides an entity with an option to first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership plans to early adopt the guidance for the period ended December 31, 2011. The adoption of the amended guidance will not have a material effect on the Partnership' s condensed consolidated financial statements.

Commitments and Contingencies	9 Months Ended Sep. 30, 2011
Commitments and Contingencies	
Commitments and Contingencies	

11. 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 Pipeline and Hazardous Materials Safety Administration issued a Notice of Probable Violation and Proposed Civil Penalty ("NOPV") (CPF No. 2-2006-5001) to both MarkWest Hydrocarbon and Equitable Production Company ("Equitable"). 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 and leased and operated by a subsidiary of the Partnership, 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 $1.1 million. In March 2011, MarkWest received an order assessing a penalty solely against Equitable for count one of the NOPV in the amount of $0.5 million and assessing a penalty jointly and severally against MarkWest and Equitable for four of the other counts in the NOPV in the amount of $0.2 million. In March 2011, the parties filed separate petitions for reconsideration, which remain pending.

In the ordinary course of business, the Partnership is a party to various other legal and regulatory 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.

Supplemental Condensed Consolidating Financial Information (Details 2) (USD $) In Thousands	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Condensed Consolidating Statements of Operations				
Total revenue	$ 507,826	$ 255,411	$ 1,171,486	$ 887,640
Operating expenses:				
Purchased product costs	188,010	156,696	515,359	434,112
Facility expenses	41,449	37,370	121,487	112,830
Selling, general and administrative expenses	20,162	17,137	60,454	55,064
Depreciation and amortization	49,700	41,555	142,912	119,946
Other operating expenses	704	2,007	5,553	2,398
Total operating expenses	300,025	254,765	845,765	724,350
Income from operations	207,801	646	325,721	163,290
Loss on redemption of debt	(133)		(43,461)	
Other (expense) income, net	(28,350)	(29,560)	(87,830)	(78,785)
Income before provision for income tax	179,318	(28,914)	194,430	84,505
Provision for income tax expense	25,864	(10,238)	26,442	10,209
Net income	153,454	(18,676)	167,988	74,296
Net income attributable to non-controlling interest	(13,142)	(8,475)	(33,208)	(19,720)
Net income attributable to the Partnership	140,312	(27,151)	134,780	54,576
Parent				
Operating expenses:				
Selling, general and administrative expenses	11,270	12,203	35,348	35,243
Depreciation and amortization	182	147	538	438
Other operating expenses		730	673	730
Total operating expenses	11,452	13,080	36,559	36,411
Income from operations	(11,452)	(13,080)	(36,559)	(36,411)
Earnings from consolidated affiliates	174,458	9,249	287,377	156,634
Loss on redemption of debt	(133)		(43,461)	
Other (expense) income, net	(20,609)	(21,539)	(67,574)	(60,675)
Income before provision for income tax	142,264	(25,370)	139,783	59,548
Provision for income tax expense	741	(21)	848	475
Net income	141,523	(25,349)	138,935	59,073
Net income attributable to the Partnership	141,523	(25,349)	138,935	59,073
Guarantor Subsidiaries				
Condensed Consolidating Statements of Operations				
Total revenue	425,142	222,004	991,993	807,585
Operating expenses:				
Purchased product costs	155,612	150,689	463,459	425,469
Facility expenses	31,351	30,931	95,701	91,074
Selling, general and administrative expenses	7,768	4,842	23,139	19,370
Depreciation and amortization	38,391	34,400	112,868	101,034

Other operating expenses	1,069	1,269	4,895	1,364
Total operating expenses	234,191	222,131	700,062	638,311
Income from operations	190,951	(127)	291,931	169,274
Earnings from consolidated affiliates	13,479	4,256	31,623	7,521
Other (expense) income, net	(4,849)	(5,097)	(10,583)	(10,427)
Income before provision for income tax	199,581	(968)	312,971	166,368
Provision for income tax expense	25,123	(10,217)	25,594	9,734
Net income	174,458	9,249	287,377	156,634
Net income attributable to the Partnership	174,458	9,249	287,377	156,634
Non-Guarantor Subsidiaries				
Condensed Consolidating Statements of Operations				
Total revenue	82,684	33,407	179,493	80,055
Operating expenses:				
Purchased product costs	32,398	6,007	51,900	8,643
Facility expenses	10,263	6,602	26,285	22,245
Selling, general and administrative expenses	2,421	1,354	6,390	4,141
Depreciation and amortization	11,314	7,117	30,010	18,739
Other operating expenses	(365)	8	(15)	304
Total operating expenses	56,031	21,088	114,570	54,072
Income from operations	26,653	12,319	64,923	25,983
Other (expense) income, net	(32)	412	(92)	1,258
Income before provision for income tax	26,621	12,731	64,831	27,241
Net income	26,621	12,731	64,831	27,241
Net income attributable to the Partnership	26,621	12,731	64,831	27,241
Consolidating Adjustments				
Operating expenses:				
Facility expenses	(165)	(163)	(499)	(489)
Selling, general and administrative expenses	(1,297)	(1,262)	(4,423)	(3,690)
Depreciation and amortization	(187)	(109)	(504)	(265)
Total operating expenses	(1,649)	(1,534)	(5,426)	(4,444)
Income from operations	1,649	1,534	5,426	4,444
Earnings from consolidated affiliates	(187,937)	(13,505)	(319,000)	(164,155)
Other (expense) income, net	(2,860)	(3,336)	(9,581)	(8,941)
Income before provision for income tax	(189,148)	(15,307)	(323,155)	(168,652)
Net income	(189,148)	(15,307)	(323,155)	(168,652)
Net income attributable to non-controlling interest	(13,142)	(8,475)	(33,208)	(19,720)
Net income attributable to the Partnership	$ (202,290)	$ (23,782)	$ (356,363)	$ (188,372)

Document and Entity Information	9 Months Ended Sep. 30, 2011	Oct. 28, 2011
Document and Entity Information		
Entity Registrant Name	MARKWEST ENERGY PARTNERS L P	
Entity Central Index Key	0001166036	
Document Type	10-Q	
Document Period End Date	Sep. 30, 2011	
Amendment Flag	false	
Current Fiscal Year End Date	--12-31	
Entity Current Reporting Status	Yes	
Entity Filer Category	Large Accelerated Filer	
Entity Common Stock, Shares Outstanding		84,939,558
Document Fiscal Year Focus	2011	
Document Fiscal Period Focus	Q3	

Earnings (Loss) Per Common Unit (Tables)	9 Months Ended Sep. 30, 2011

Earnings (Loss) Per Common Unit

Computation of basic and diluted net income (loss) per common unit

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Net income (loss) attributable to the Partnership	$ 140,312	$ (27,151)	$ 134,780	$ 54,576
Less: Income allocable to phantom units	1,287	370	1,288	921
Income (loss) available for common unitholders	$ 139,025	$ (27,521)	$ 133,492	$ 53,655
Weighted average common units outstanding - basic	78,619	71,438	76,118	69,685
Effect of dilutive instruments (1)	141	–	158	146
Weighted average common units outstanding - diluted (1)	78,760	71,438	76,276	69,831
Net income (loss) attributable to the Partnership's common unitholders per common unit				
Basic	$ 1.77	$ (0.39)	$ 1.75	$ 0.77
Diluted	$ 1.77	$ (0.39)	$ 1.75	$ 0.77

(1) Dilutive instruments include TSR Performance Units and are based on the number of units, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For the three months ended September 30, 2010, 247 units were excluded from the calculation of diluted units because the impact was anti-dilutive.

Segment Information

9 Months Ended Sep. 30, 2011

Segment Information

Segment Information

15. Segment Information

The Partnership prepares segment information in accordance with GAAP. Certain items below *Income from operations* in the accompanying Condensed Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any gains (losses) from derivative instruments are not allocated to individual segments. Management does not consider these items allocable to or controllable by any individual segment and therefore excludes these items when evaluating segment performance. Segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

The tables below present the Partnership' s segment profit measure, *Operating income before items not allocated to segments*, for the three and nine months ended September 30, 2011 and 2010 and capital expenditures for the nine months ended September 30, 2011 and 2010 for the reported segments (in thousands).

Three months ended September 30, 2011:	Southwest	Northeast	Liberty	Gulf Coast	Total
Segment revenue	$ 241,998	$ 55,920	$ 78,586	$ 26,868	$ 403,372
Purchased product costs	141,067	15,947	32,270	–	189,284
Net operating margin	100,931	39,973	46,316	26,868	214,088
Facility expenses	21,043	6,879	9,108	9,798	46,828
Portion of operating income attributable to non-controlling interests	1,227	–	18,223	–	19,450
Operating income before items not allocated to segments	$ 78,661	$ 33,094	$ 18,985	$ 17,070	$ 147,810

Three months ended September 30, 2010:	Southwest	Northeast	Liberty	Gulf Coast	Total
Segment revenue	$ 159,044	$ 83,400	$ 28,606	$ 21,320	$ 292,370
Purchased product costs	74,835	55,879	5,986	–	136,700
Net operating margin	84,209	27,521	22,620	21,320	155,670
Facility expenses	20,659	5,268	5,668	8,785	40,380
Portion of operating income attributable to non-controlling interests	1,906	–	6,772	–	8,678
Operating income before items not allocated to segments	$ 61,644	$ 22,253	$ 10,180	$ 12,535	$ 106,612

The following is a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to income (loss) before provision for income tax for the three months ended September 30, 2011 and 2010 (in thousands).

	Three months ended September 30, 2011	Three months ended September 30, 2010
Total segment revenue	$ 403,372	$ 292,370
Derivative gain (loss) not allocated to segments	106,943	(36,959)
Revenue deferral adjustment (1)	(2,489)	–
Total revenue	$ 507,826	$ 255,411
Operating income before items not allocated to segments	$ 147,810	$ 106,612

Portion of operating income attributable to non-controlling interests	19,450	8,678
Derivative gain (loss) not allocated to segments	111,004	(56,391)
Revenue deferral adjustment (1)	(2,489)	–
Compensation expense included in facility expenses not allocated to segments	(263)	(404)
Facility expenses adjustments	2,855	2,850
Selling, general and administrative expenses	(20,162)	(17,137)
Depreciation	(38,715)	(31,362)
Amortization of intangible assets	(10,985)	(10,193)
Loss on disposal of property, plant and equipment	(147)	(1,937)
Accretion of asset retirement obligations	(557)	(70)
Income from operations	207,801	646
Loss from unconsolidated affiliate	(507)	–
Interest income	62	422
Interest expense	(26,899)	(26,433)
Amortization of deferred financing costs and discount (a component of interest expense)	(1,002)	(3,625)
Loss on redemption of debt	(133)	–
Miscellaneous (expense) income, net	(4)	76
Income (loss) before provision for income tax	$ 179,318	$ (28,914)

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the three months ended September 30, 2011, approximately $0.2 million and $2.3 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

Nine months ended September 30, 2011:	**Southwest**	**Northeast**	**Liberty**	**Gulf Coast**	**Total**
Segment revenue	$679,347	$201,687	$168,142	$ 73,310	$1,122,486
Purchased product costs	373,251	72,527	51,715	–	497,493
Net operating margin	306,096	129,160	116,427	73,310	624,993
Facility expenses	62,055	19,402	22,875	27,100	131,432
Portion of operating income attributable to non-controlling interests	3,745	–	45,782	–	49,527
Operating income before items not allocated to segments	$240,296	$109,758	$ 47,770	$ 46,210	$ 444,034
Capital expenditures	$ 80,069	$ 17,768	$256,877	$ 1,282	$ 355,996

Capital expenditures not allocated to segments	3,930
Total capital expenditures	$ 359,926

Nine months ended September 30, 2010:	Southwest	Northeast	Liberty	Gulf Coast	Total
Segment revenue	$ 479,051	$ 276,570	$ 66,354	$ 62,958	$ 884,933
Purchased product costs	220,849	179,700	8,570	–	409,119
Net operating margin	258,202	96,870	57,784	62,958	475,814
Facility expenses	60,543	14,555	19,121	23,875	118,094
Portion of operating income attributable to non-controlling interests	4,962	–	15,617	–	20,579
Operating income before items not allocated to segments	$ 192,697	$ 82,315	$ 23,046	$ 39,083	$ 337,141
Capital expenditures	$ 89,949	$ 1,918	$ 275,620	$ 3,418	$ 370,905
Capital expenditures not allocated to segments					3,268
Total capital expenditures					$ 374,173

The following is a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to income before provision for income tax for the nine months ended September 30, 2011 and 2010 (in thousands).

	Nine months ended September 30,	
	2011	2010
Total segment revenue	$ 1,122,486	$ 884,933
Derivative gain not allocated to segments	61,854	2,707
Revenue deferral adjustment (1)	(12,854)	–
Total revenue	$ 1,171,486	$ 887,640
Operating income before items not allocated to segments	$ 444,034	$ 337,141
Portion of operating income attributable to non-controlling interests	49,527	20,579
Derivative gain (loss) not allocated to segments	46,859	(21,850)
Revenue deferral adjustment (1)	(12,854)	–
Compensation expense included in facility expenses not allocated to segments	(1,491)	(1,412)
Facility expenses adjustments	8,565	6,240
Selling, general and administrative expenses	(60,454)	(55,064)
Depreciation	(110,280)	(89,367)
Amortization of intangible assets	(32,632)	(30,579)
Loss on disposal of property, plant and equipment	(4,619)	(2,116)

Accretion of asset retirement obligations	(934)	(282)
Income from operations	325,721	163,290
(Loss) earnings from unconsolidated affiliate	(1,262)	1,517
Interest income	214	1,185
Interest expense	(83,036)	(75,970)
Amortization of deferred financing costs and discount (a component of interest expense)	(3,873)	(8,517)
Derivative gain related to interest expense	–	1,871
Loss on redemption of debt	(43,461)	–
Miscellaneous income, net	127	1,129
Income before provision for income tax	$ 194,430	$ 84,505

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership will perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the nine months ended September 30, 2011, approximately $6.9 million and $5.9 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

The tables below present information about segment assets as of September 30, 2011 and December 31, 2010 (in thousands):

SEGMENT ASSETS:

	September 30, 2011	December 31, 2010
Southwest	$ 1,680,619	$ 1,646,607
Northeast	479,576	244,219
Liberty	1,039,619	743,943
Gulf Coast	569,241	573,456
Total segment assets	3,769,055	3,208,225
Assets not allocated to segments:		
Certain cash and cash equivalents	82,626	49,776
Fair value of derivatives	72,043	4,762
Investment in unconsolidated affiliate	27,126	28,688
Other (1)	35,351	41,911
Total assets	$ 3,986,201	$ 3,333,362

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

Condensed Consolidated Balance Sheets (Parenthetical) (USD $) In Thousands	Sep. 30, 2011	Dec. 31, 2010
Condensed Consolidated Balance Sheets		
Accumulated amortization, intangibles	$ 157,183	$ 124,568
Accumulated amortization, deferred financing costs	13,809	11,445
Accumulated amortization, deferred contract cost	2,184	1,950
Long-term debt, discounts	1,499	1,566
Common units issued (in units)	79,190	71,440
Common units outstanding (in units)	79,190	71,440
Cash and cash equivalents	159,177	67,450
Restricted cash and cash equivalents	25,143	0
Receivables, net	192,271	179,209
Inventories	43,381	23,432
Fair value of derivative instruments	29,260	4,345
Other current assets	8,745	8,020
Property, plant and equipment	3,121,547	2,613,027
Accumulated depreciation	401,729	294,003
Restricted cash	3,007	28,001
Other long-term assets	1,621	1,486
Accounts payable	183,695	122,473
Accrued liabilities	168,168	153,869
Other long-term liabilities	118,835	105,349
Total Variable Interest Entity		
Condensed Consolidated Balance Sheets		
Cash and cash equivalents	72,171	2,913
Restricted cash and cash equivalents	25,143	0
Receivables, net	13,451	43,783
Inventories	21,919	8,431
Fair value of derivative instruments	280	0
Other current assets	1,168	272
Property, plant and equipment	1,116,112	849,986
Accumulated depreciation	67,455	38,169
Restricted cash	3,007	28,001
Other long-term assets	361	383
Accounts payable	35,724	5,945
Accrued liabilities	68,781	64,713
Other long-term liabilities	$ 163	$ 154

Supplemental Condensed Consolidating Financial Information (Tables)	9 Months Ended Sep. 30, 2011

Supplemental Condensed Consolidating Financial Information

Condensed Consolidating Balance Sheet

Condensed Consolidating Balance Sheets

	As of September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 3	$ 86,423	$ 72,751	$ –	$ 159,177
Restricted cash	–	–	25,143	–	25,143
Receivables and other current assets	846	222,835	36,806	–	260,487
Intercompany receivables	9,548	8,668	24,505	(42,721)	–
Fair value of derivative instruments	–	28,980	280	–	29,260
Total current assets	10,397	346,906	159,485	(42,721)	474,067
Total property, plant and equipment, net	4,191	1,681,413	1,049,629	(15,415)	2,719,818
Other long-term assets:					
Restricted cash	–	–	3,007	–	3,007
Investment in unconsolidated affiliate	–	27,126	–	–	27,126
Investment in consolidated affiliates	2,659,809	554,896	–	(3,214,705)	–
Intangibles, net of accumulated amortization	–	614,201	551	–	614,752
Fair value of derivative instruments	–	42,783	–	–	42,783
Intercompany notes receivable	215,310	–	–	(215,310)	–
Other long-term assets	33,733	70,554	361	–	104,648

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total assets	$2,923,440	$ 3,337,879	$1,213,033	$ (3,488,151)	$3,986,201
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 8,568	$ 33,807	$ 346	$ (42,721)	$ –
Fair value of derivative instruments	–	65,499	–	–	65,499
Other current liabilities	37,409	209,828	104,637	–	351,874
Total current liabilities	45,977	309,134	104,983	(42,721)	417,373
Deferred income taxes	1,623	27,142	–	–	28,765
Intercompany notes payable	–	192,310	23,000	(215,310)	–
Fair value of derivative instruments	–	34,161	–	–	34,161
Long-term debt, net of discounts	1,477,963	–	–	–	1,477,963
Other long-term liabilities	3,316	115,323	196	–	118,835
Equity:					
MarkWest Energy Partners, L.P. partners' capital	1,394,561	2,659,809	1,084,854	(3,760,078)	1,379,146
Non-controlling interest in consolidated subsidiaries	–	–	–	529,958	529,958
Total equity	1,394,561	2,659,809	1,084,854	(3,230,120)	1,909,104
Total liabilities and equity	$2,923,440	$ 3,337,879	$1,213,033	$ (3,488,151)	$3,986,201

	As of December 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ –	$ 63,850	$ 3,600	$ –	$ 67,450
Receivables and other current assets	1,708	172,209	52,834	–	226,751
Intercompany receivables	1,440,302	1,099	7,635	(1,449,036)	–
Fair value of derivative instruments	–	4,345	–	–	4,345

Total current assets	1,442,010	241,503	64,069	(1,449,036)	298,546
Total property, plant and equipment, net	4,623	1,512,763	812,898	(11,260)	2,319,024
Other long-term assets:					
Restricted cash	–	–	28,001	–	28,001
Investment in unconsolidated affiliate	–	28,688	–	–	28,688
Investment in consolidated affiliates	716,673	368,864	–	(1,085,537)	–
Intangibles, net of accumulated amortization	–	613,000	578	–	613,578
Fair value of derivative instruments	–	417	–	–	417
Intercompany notes receivable	197,710	–	–	(197,710)	–
Other long-term assets	32,587	12,139	382	–	45,108
Total assets	$2,393,603	$ 2,777,374	$ 905,928	$(2,743,543)	$3,333,362
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 672	$ 1,447,799	$ 565	$(1,449,036)	$ –
Fair value of derivative instruments	–	65,489	–	–	65,489
Other current liabilities	31,882	173,667	70,804	–	276,353
Total current liabilities	32,554	1,686,955	71,369	(1,449,036)	341,842
Deferred income taxes	2,533	7,894	–	–	10,427
Intercompany notes payable	–	197,710	–	(197,710)	–
Fair value of derivative instruments	–	66,290	–	–	66,290
Long-term debt, net of discounts	1,273,434	–	–	–	1,273,434
Other long-term liabilities	3,319	101,852	178	–	105,349
Equity:					
MarkWest Energy	1,081,763	716,673	834,381	(1,562,314)	1,070,503

Partners, L.P. partners' capital					
Non-controlling interest in consolidated subsidiaries	–	–	–	465,517	465,517
Total equity	1,081,763	716,673	834,381	(1,096,797)	1,536,020
Total liabilities and equity	$2,393,603	$ 2,777,374	$ 905,928	$ (2,743,543)	$ 3,333,362

[Condensed Consolidating Statement of Operations]

Condensed Consolidating Statements of Operations

	Three Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 425,142	$ 82,684	$ –	$ 507,826
Operating expenses:					
Purchased product costs	–	155,612	32,398	–	188,010
Facility expenses	–	31,351	10,263	(165)	41,449
Selling, general and administrative expenses	11,270	7,768	2,421	(1,297)	20,162
Depreciation and amortization	182	38,391	11,314	(187)	49,700
Other operating expenses	–	1,069	(365)	–	704
Total operating expenses	11,452	234,191	56,031	(1,649)	300,025
(Loss) income from operations	(11,452)	190,951	26,653	1,649	207,801
Earnings from consolidated affiliates	174,458	13,479	–	(187,937)	–
Loss on redemption of debt	(133)	–	–	–	(133)
Other expense, net	(20,609)	(4,849)	(32)	(2,860)	(28,350)
Income before provision for income tax	142,264	199,581	26,621	(189,148)	179,318
Provision for income tax expense	741	25,123	–	–	25,864
Net income	141,523	174,458	26,621	(189,148)	153,454
Net income attributable to non-controlling interest	–	–	–	(13,142)	(13,142)
Net income attributable to the Partnership	$141,523	$ 174,458	$ 26,621	$ (202,290)	$ 140,312

	Three Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 222,004	$ 33,407	$ –	$ 255,411
Operating expenses:					
Purchased product costs	–	150,689	6,007	–	156,696
Facility expenses	–	30,931	6,602	(163)	37,370
Selling, general and administrative expenses	12,203	4,842	1,354	(1,262)	17,137
Depreciation and amortization	147	34,400	7,117	(109)	41,555
Other operating expenses	730	1,269	8	–	2,007
Total operating expenses	13,080	222,131	21,088	(1,534)	254,765
(Loss) income from operations	(13,080)	(127)	12,319	1,534	646
Earnings from consolidated affiliates	9,249	4,256	–	(13,505)	–
Other (expense) income, net	(21,539)	(5,097)	412	(3,336)	(29,560)
(Loss) income before provision for income tax	(25,370)	(968)	12,731	(15,307)	(28,914)
Provision for income tax benefit	(21)	(10,217)	–	–	(10,238)
Net (loss) income	(25,349)	9,249	12,731	(15,307)	(18,676)
Net income attributable to non-controlling interest	–	–	–	(8,475)	(8,475)
Net (loss) income attributable to the Partnership	$(25,349)	$ 9,249	$ 12,731	$ (23,782)	$ (27,151)

	Nine Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 991,993	$ 179,493	$ –	$1,171,486
Operating expenses:					
Purchased product costs	–	463,459	51,900	–	515,359
Facility expenses	–	95,701	26,285	(499)	121,487
Selling, general and	35,348	23,139	6,390	(4,423)	60,454

administrative expenses					
Depreciation and amortization	538	112,868	30,010	(504)	142,912
Other operating expenses	673	4,895	(15)	–	5,553
Total operating expenses	36,559	700,062	114,570	(5,426)	845,765
(Loss) income from operations	(36,559)	291,931	64,923	5,426	325,721
Earnings from consolidated affiliates	287,377	31,623	–	(319,000)	–
Loss on redemption of debt	(43,461)	–	–	–	(43,461)
Other expense, net	(67,574)	(10,583)	(92)	(9,581)	(87,830)
Income before provision for income tax	139,783	312,971	64,831	(323,155)	194,430
Provision for income tax expense	848	25,594	–	–	26,442
Net income	138,935	287,377	64,831	(323,155)	167,988
Net income attributable to non-controlling interest	–	–	–	(33,208)	(33,208)
Net income attributable to the Partnership	$138,935	$ 287,377	$ 64,831	$ (356,363)	$ 134,780

	Nine Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ –	$ 807,585	$ 80,055	$ –	$ 887,640
Operating expenses:					
Purchased product costs	–	425,469	8,643	–	434,112
Facility expenses	–	91,074	22,245	(489)	112,830
Selling, general and administrative expenses	35,243	19,370	4,141	(3,690)	55,064
Depreciation and amortization	438	101,034	18,739	(265)	119,946
Other operating expenses	730	1,364	304	–	2,398
Total operating expenses	36,411	638,311	54,072	(4,444)	724,350
(Loss) income from operations	(36,411)	169,274	25,983	4,444	163,290

Earnings from consolidated affiliates	156,634	7,521	–	(164,155)	–
Other (expense) income, net	(60,675)	(10,427)	1,258	(8,941)	(78,785)
Income before provision for income tax	59,548	166,368	27,241	(168,652)	84,505
Provision for income tax expense	475	9,734	–	–	10,209
Net income	59,073	156,634	27,241	(168,652)	74,296
Net income attributable to non-controlling interest	–	–	–	(19,720)	(19,720)
Net income attributable to the Partnership	$59,073	$ 156,634	$ 27,241	$ (188,372)	$ 54,576

[Condensed Consolidating Statements of Cash Flows]

Condensed Consolidating Statements of Cash Flows

	Nine Months Ended September 30, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$ (89,044)	$ 303,401	$ 121,551	$ (4,659)	$ 331,249
Cash flows from investing activities:					
Capital expenditures	(785)	(100,155)	(264,996)	6,010	(359,926)
Acquisitions	–	(230,728)	–	–	(230,728)
Equity investments	(34,246)	(204,428)	–	238,674	–
Distributions from consolidated affiliates	37,978	50,019	–	(87,997)	–
Investment in intercompany notes, net	(17,600)	–	–	17,600	–
Proceeds from disposal of property, plant and equipment	–	365	3,954	(1,351)	2,968
Net cash used in investing activities	(14,653)	(484,927)	(261,042)	172,936	(587,686)
Cash flows from financing activities:					
Proceeds from revolving credit facility	1,074,700	–	–	–	1,074,700
Payments of revolving credit facility	(929,600)	–	–	–	(929,600)
Proceeds from long-term debt	499,000	–	–	–	499,000
Payments of long-term debt	(440,638)	–	–	–	(440,638)
Payments of premiums on redemption of long-term debt	(39,642)	–	–	–	(39,642)

(Payments of) proceeds from intercompany notes, net	–	(5,400)	23,000	(17,600)	–
Payments for debt issuance costs, deferred financing costs and registration costs	(7,795)	–	–	–	(7,795)
Contributions to guarantor subsidiaries, net	–	34,246	–	(34,246)	–
Contributions to joint ventures, net	–	–	284,760	(204,428)	80,332
Payments of SMR liability	–	(1,390)	–	–	(1,390)
Proceeds from public equity offering, net	323,492	–	–	–	323,492
Share-based payment activity	(6,354)	1,089	–	–	(5,265)
Payment of distributions	(155,931)	(37,978)	(99,118)	87,997	(205,030)
Intercompany advances, net	(213,532)	213,532			
Net cash provided by financing activities	103,700	204,099	208,642	(168,277)	348,164
Net increase in cash	3	22,573	69,151	–	91,727
Cash and cash equivalents at beginning of year	–	63,850	3,600	–	67,450
Cash and cash equivalents at end of period	$ 3	$ 86,423	$ 72,751	$ –	$ 159,177

	Nine Months Ended September 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$(63,740)	$ 230,279	$ 35,460	$ (4,761)	$ 197,238
Cash flows from investing activities:					
Capital expenditures	(569)	(97,039)	(281,326)	4,761	(374,173)
Equity investments	(32,442)	(130,074)	–	162,516	–
Distributions from consolidated affiliates	33,237	14,512	–	(47,749)	–
Payments for intercompany notes, net	(1,550)	–	–	1,550	–
Proceeds from disposal of property, plant and equipment	–	524	–	–	524
Net cash used in investing activities	(1,324)	(212,077)	(281,326)	121,078	(373,649)
Cash flows from financing activities:					
Proceeds from revolving credit facility	421,304	–	–	–	421,304

Payments of revolving credit facility	(378,804)	–	–	–	(378,804)
Proceeds from intercompany notes, net	–	1,550	–	(1,550)	–
Payments for debt issuance costs, deferred financing costs and registration costs	(11,230)	–	–	–	(11,230)
Contributions from parent, net	–	32,442	–	(32,442)	–
Contributions to joint ventures, net	–	–	278,131	(130,074)	148,057
Payments of SMR liability	–	(912)	–	–	(912)
Proceeds from public offering, net	142,255	–	–	–	142,255
Share-based payment activity	(3,834)	97	–	–	(3,737)
Payment of distributions	(134,949)	(33,237)	(19,342)	47,749	(139,779)
Intercompany advances, net	30,322	(30,322)	–	–	–
Net cash provided by (used in) financing activities	65,064	(30,382)	258,789	(116,317)	177,154
Net (decrease) increase in cash	–	(12,180)	12,923	–	743
Cash and cash equivalents at beginning of year	–	74,448	23,304	–	97,752
Cash and cash equivalents at end of period	$ –	$ 62,268	$ 36,227	$ –	$ 98,495

Income Taxes (Details) (USD $) In Thousands, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2011	Sep. 30, 2010
Provision for income tax reconciliation				
Income before provision for income tax	$ 179,318	$ (28,914)	$ 194,430	$ 84,505
Federal income tax at statutory rate			11,198	1,856
Permanent items			22	6
State income taxes net of federal benefit			1,737	664
Provision on income from Class A units			13,359	8,251
Other			126	(568)
Total provision for income tax	25,864	(10,238)	26,442	10,209
Corporation				
Provision for income tax reconciliation				
Income before provision for income tax			31,993	5,303
Federal statutory income tax rate (as a percent)			35.00%	35.00%
Federal income tax at statutory rate			11,198	1,856
Permanent items			22	6
State income taxes net of federal benefit			889	190
Provision on income from Class A units			13,359	8,251
Other			126	(568)
Total provision for income tax			25,594	9,735
Partnership				
Provision for income tax reconciliation				
Income before provision for income tax			166,649	83,603
Federal statutory income tax rate (as a percent)			0.00%	0.00%
State income taxes net of federal benefit			848	474
Total provision for income tax			848	474
Eliminations				
Provision for income tax reconciliation				
Income before provision for income tax			$ (4,212)	$ (4,401)
Federal statutory income tax rate (as a percent)			0.00%	0.00%

Supplemental Cash Flow Information (Details) (USD $) In Thousands	9 Months Ended	
	Sep. 30, 2011	Sep. 30, 2010
Supplemental Cash Flow Information		
Cash paid for interest, net of amounts capitalized	$ 76,876	$ 64,448
Cash paid for income taxes, net of refunds	5,051	8,760
Supplemental schedule of non-cash investing and financing activities:		
Accrued property, plant and equipment	85,666	53,381
Interest capitalized on construction in progress	571	2,719
Issuance of common units for vesting of share-based payment awards	$ 5,412	$ 7,238

Long-Term Debt (Details) (USD $)	3 Months Ended	9 Months Ended					3 Months Ended			9 Months Ended		9 Months Ended				3 Months Ended		3 Months Ended		3 Months Ended	
	Sep. 30, 2011	Sep. 30, 2011	Dec. 31, 2010	Sep. 30, 2011 Revolving credit facility	Sep. 07, 2011 Revolving credit facility	Jun. 15, 2011 Revolving credit facility	Sep. 30, 2011 Senior Notes	Mar. 31, 2011 Senior Notes	Dec. 31, 2010 Senior Notes	Sep. 30, 2011 Senior Notes, 8.5% interest, issued July 2006 and due July 2016	Dec. 31, 2010 Senior Notes, 8.5% interest, issued July 2006 and due July 2016	Sep. 30, 2011 Senior Notes, 8.75% interest, issued April and May 2008 and due April 2018	Dec. 31, 2010 Senior Notes, 8.75% interest, issued April and May 2008 and due April 2018	Sep. 30, 2011 Senior Notes, 6.75% interest, issued November 2010 and due November 2020	Dec. 31, 2010 Senior Notes, 6.75% interest, issued November 2010 and due November 2020	Mar. 31, 2011 Senior Notes, 6.5% interest, issued February and March 2011 and due August 2021	Sep. 30, 2011 Senior Notes, 6.5% interest, issued February and March 2011 and due August 2021	Mar. 31, 2011 Senior Notes, 6.5% interest, issued February 2011 and due August 2021	Feb. 24, 2011 Senior Notes, 6.5% interest, issued February 2011 and due August 2021	Mar. 31, 2011 Senior Notes, 6.5% interest, issued March 2011 and due August 2021	Mar. 10, 2011 Senior Notes, 6.5% interest, issued March 2011 and due August 2021
Long-Term Debt																					
Long-term debt, net of discounts	$ 1,477,963,000	$ 1,477,963,000	$ 1,273,434,000	$ 145,100,000							$ 274,358,000	$ 333,807,000	$ 499,076,000	$ 500,000,000	$ 500,000,000		$ 499,056,000				
Debt instrument, stated interest rate percentage (as a percent)				4.25%						8.50%	8.50%	8.75%	8.75%	6.75%	6.75%		6.50%		6.50%		6.50%
Long-term debt, discounts	1,499,000	1,499,000	1,566,000							0	642,000	555,000	924,000				944,000				
Estimate aggregate fair value of debt							1,350,200,000		1,333,900,000												
Credit facility maximum borrowing capacity					750,000,000	745,000,000															
Uncommitted accordion feature					250,000,000	155,000,000															
Reduction in interest rate ranges, basis points (as a percent)					0.75%																
Letters of credit outstanding amount				27,300,000																	
Credit facility remaining borrowing capacity				577,600,000																	
Aggregate principal amount of public offering																		300,000,000		200,000,000	
Issue price as percentage of par value (as a percent)																				99.50%	
Aggregate net proceeds from issuance of debt																492,000,000					
Aggregate principal amount of debt repurchased										272,200,000		165,600,000									
Pre-tax loss on redemption of debt	(133,000)	(43,461,000)					100,000	43,300,000													
Write off of the unamortized discount and deferred finance costs on extinguishment of debt								3,800,000													
Tender premiums and third-party expenses								$ 39,500,000													

Equity (Details) (USD $) In Thousands, except Share data in Millions, unless otherwise specified	1 Months Ended		3 Months Ended				9 Months Ended	
	Jul. 31, 2011	Jan. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2011	Sep. 30, 2010
Equity Offering								
Issuance of units in public offering, net of offering costs (in units)	4.00	3.45						
Issuance of units in public offering, net of offering costs	$ 185,000	$ 138,000					$ 323,492	$ 142,255
Distributions of Available Cash								
Distribution per common unit (in dollars per unit)			$ 0.73	$ 0.70	$ 0.67	$ 0.65		
Declaration Date			October 18, 2011	July 21, 2011	April 21, 2011	January 27, 2011		
Record Date			November 7,2011	August1,2011	May2,2011	February7,2011		
Payment Date			November 14,2011	August12,2011	May13,2011	February14,2011		

Supplemental Condensed Consolidating Financial Information (Details) (USD $) In Thousands	Sep. 30, 2011	Dec. 31, 2010	Sep. 30, 2010	Dec. 31, 2009
Current assets:				
Cash and cash equivalents	$ 159,177	$ 67,450	$ 98,495	$ 97,752
Restricted cash	25,143	0		
Receivables and other current assets	260,487	226,751		
Fair value of derivative instruments	29,260	4,345		
Total current assets	474,067	298,546		
Total property, plant and equipment, net	2,719,818	2,319,024		
Other long-term assets:				
Restricted cash	3,007	28,001		
Investment in unconsolidated affiliate	27,126	28,688		
Intangibles, net of accumulated amortization	614,752	613,578		
Fair value of derivative instruments	42,783	417		
Other long-term assets	104,648	45,108		
Total assets	3,986,201	3,333,362		
Current liabilities:				
Fair value of derivative instruments	65,499	65,489		
Other current liabilities	351,874	276,353		
Total current liabilities	417,373	341,842		
Deferred income taxes	28,765	10,427		
Fair value of derivative instruments	34,161	66,290		
Long-term debt, net of discounts	1,477,963	1,273,434		
Other long-term liabilities	118,835	105,349		
Equity:				
MarkWest Energy Partners, L.P. partners' capital	1,379,146	1,070,503		
Non-controlling interest in consolidated subsidiaries	529,958	465,517		
Total equity	1,909,104	1,536,020	1,612,784	1,379,393
Total liabilities and equity	3,986,201	3,333,362		
Parent				
Current assets:				
Cash and cash equivalents	3			
Receivables and other current assets	846	1,708		
Intercompany receivables	9,548	1,440,302		
Total current assets	10,397	1,442,010		
Total property, plant and equipment, net	4,191	4,623		
Other long-term assets:				
Investment in consolidated affiliates	2,659,809	716,673		
Intercompany notes receivable	215,310	197,710		
Other long-term assets	33,733	32,587		
Total assets	2,923,440	2,393,603		

Current liabilities:				
Intercompany payables	8,568	672		
Other current liabilities	37,409	31,882		
Total current liabilities	45,977	32,554		
Deferred income taxes	1,623	2,533		
Long-term debt, net of discounts	1,477,963	1,273,434		
Other long-term liabilities	3,316	3,319		
Equity:				
MarkWest Energy Partners, L.P. partners' capital	1,394,561	1,081,763		
Total equity	1,394,561	1,081,763		
Total liabilities and equity	2,923,440	2,393,603		
Guarantor Subsidiaries				
Current assets:				
Cash and cash equivalents	86,423	63,850	62,268	74,448
Receivables and other current assets	222,835	172,209		
Intercompany receivables	8,668	1,099		
Fair value of derivative instruments	28,980	4,345		
Total current assets	346,906	241,503		
Total property, plant and equipment, net	1,681,413	1,512,763		
Other long-term assets:				
Investment in unconsolidated affiliate	27,126	28,688		
Investment in consolidated affiliates	554,896	368,864		
Intangibles, net of accumulated amortization	614,201	613,000		
Fair value of derivative instruments	42,783	417		
Other long-term assets	70,554	12,139		
Total assets	3,337,879	2,777,374		
Current liabilities:				
Intercompany payables	33,807	1,447,799		
Fair value of derivative instruments	65,499	65,489		
Other current liabilities	209,828	173,667		
Total current liabilities	309,134	1,686,955		
Deferred income taxes	27,142	7,894		
Intercompany notes payable	192,310	197,710		
Fair value of derivative instruments	34,161	66,290		
Other long-term liabilities	115,323	101,852		
Equity:				
MarkWest Energy Partners, L.P. partners' capital	2,659,809	716,673		
Total equity	2,659,809	716,673		
Total liabilities and equity	3,337,879	2,777,374		
Non-Guarantor Subsidiaries				
Current assets:				
Cash and cash equivalents	72,751	3,600	36,227	23,304
Restricted cash	25,143			
Receivables and other current assets	36,806	52,834		

Intercompany receivables	24,505	7,635
Fair value of derivative instruments	280	
Total current assets	159,485	64,069
Total property, plant and equipment, net	1,049,629	812,898
Other long-term assets:		
Restricted cash	3,007	28,001
Intangibles, net of accumulated amortization	551	578
Other long-term assets	361	382
Total assets	1,213,033	905,928
Current liabilities:		
Intercompany payables	346	565
Other current liabilities	104,637	70,804
Total current liabilities	104,983	71,369
Intercompany notes payable	23,000	
Other long-term liabilities	196	178
Equity:		
MarkWest Energy Partners, L.P. partners' capital	1,084,854	834,381
Total equity	1,084,854	834,381
Total liabilities and equity	1,213,033	905,928
Consolidating Adjustments		
Current assets:		
Intercompany receivables	(42,721)	(1,449,036)
Total current assets	(42,721)	(1,449,036)
Total property, plant and equipment, net	(15,415)	(11,260)
Other long-term assets:		
Investment in consolidated affiliates	(3,214,705)	(1,085,537)
Intercompany notes receivable	(215,310)	(197,710)
Total assets	(3,488,151)	(2,743,543)
Current liabilities:		
Intercompany payables	(42,721)	(1,449,036)
Total current liabilities	(42,721)	(1,449,036)
Intercompany notes payable	(215,310)	(197,710)
Equity:		
MarkWest Energy Partners, L.P. partners' capital	(3,760,078)	(1,562,314)
Non-controlling interest in consolidated subsidiaries	529,958	465,517
Total equity	(3,230,120)	(1,096,797)
Total liabilities and equity	$ (3,488,151)	$ (2,743,543)

Supplemental Cash Flow Information (Tables)	9 Months Ended Sep. 30, 2011
Supplemental Cash Flow Information	
Information regarding supplemental cash flow information	

	Nine months ended September 30,	
	2011	2010
Supplemental disclosures of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ 76,876	$ 64,448
Cash paid for income taxes, net of refunds	5,051	8,760
Supplemental schedule of non-cash investing and financing activities:		
Accrued property, plant and equipment	$ 85,666	$ 53,381
Interest capitalized on construction in progress	571	2,719
Issuance of common units for vesting of share-based payment awards	5,412	7,238