American Midstream Partners, LP
Form 10-Q
August 14, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2012

or

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

For the transition period from to

Commission File Number: 001-35257

AMERICAN MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**27-0855785**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1614 15th Street, Suite 300 Denver, CO	**80202**
(Address of principal executive offices)	**(Zip code)**

(720) 457-6060

(Registrant s telephone number, including area code)

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. x 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). x 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 the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

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

There were 4,581,850 common units and 4,526,066 subordinated units of American Midstream Partners, LP outstanding as of July 31, 2012. Our common units trade on the New York Stock Exchange under the ticker symbol AMID.

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Glossary of Terms

As generally used in the energy industry and in this Quarterly Report on Form 10-Q (the **Quarterly Report**), the identified terms have the following meanings:

ASC	Accounting Standards Codification; trademark of the Financial Accounting Standards Board (FASB).
Bbl	Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.
BBtu	Billion British thermal units: one billion cubic feet.
Btu	British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
/d	Per day.
FERC	Federal Energy Regulatory Commission.
GAAP	General Accepted Accounting Principles: Accounting principles generally accepted in the United States of America.
gal	Gallons.
MBbl	One thousand barrels.
Mcf	One thousand cubic feet.
MMBbl	One million barrels.
MMBtu	One million British thermal units.
MMcf	One million cubic feet.
NGL or NGLs	Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutene and natural gasoline s that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

As used in this Quarterly Report, unless the context otherwise requires, we, us, our, the Partnership and similar terms refer to American Midstream Partners LP, together with its consolidated subsidiaries.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

American Midstream Partners, LP and Subsidiaries

Condensed Consolidated Balance Sheets

(Unaudited)

	June 30, 2012	December 31, 2011
	(in thousands)	
Assets		
Current assets		
Cash and cash equivalents	$ 1,038	$ 871
Accounts receivable	1,273	1,218
Unbilled revenue	14,089	19,745
Risk management assets	2,721	456
Funds held in escrow	5,500	
Other current assets	3,196	3,323
Total current assets	27,817	25,613
Property, plant and equipment, net	161,525	170,231
Risk management assets - long term	594	
Other assets, net	4,448	3,707
Total assets	$ 194,384	$ 199,551
Liabilities and Partners Capital		
Current liabilities		
Accounts payable	$ 743	$ 837
Accrued gas purchases	9,451	14,715
Risk management liabilities		635
Accrued expenses and other current liabilities	5,317	7,086
Total current liabilities	15,511	23,273
Other liabilities	8,490	8,612
Long-term debt	72,260	66,270
Total liabilities	96,261	98,155
Commitments and contingencies (see Note 12)		
Partners capital		
General partner interest (185 and 185 thousand units issued and outstanding as of June 30, 2012 and December 31, 2011, respectively)	1,360	1,091
Limited partner interest (9,108 and 9,087 thousand units issued and outstanding as of June 30, 2012 and December 31, 2011, respectively)	96,331	99,890
Accumulated other comprehensive income	432	415
Total partners capital	98,123	101,396
Total liabilities and partners capital	$ 194,384	$ 199,551

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

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American Midstream Partners, LP and Subsidiaries

Condensed Consolidated Statements of Operations

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(in thousands, except for per unit amounts)			
Revenue	$ 42,889	$ 66,030	$ 90,278	$ 133,369
Realized gain (loss) on early termination of commodity derivatives		(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives	3,171	2,602	3,494	(972)
Total revenue	46,060	65,634	93,772	129,399
Operating expenses:				
Purchases of natural gas, NGLs and condensate	30,239	55,413	63,449	110,366
Direct operating expenses	3,527	3,105	6,767	6,163
Selling, general and administrative expenses	3,668	2,670	6,997	4,871
Transaction expenses		(7)		281
Equity compensation expense	467	2,184	798	2,658
Depreciation and accretion expense	5,124	5,170	10,283	10,207
(Gain) loss on sale of assets, net	(117)		(122)	
Total operating expenses	42,908	68,535	88,172	134,546
Operating income (loss)	3,152	(2,901)	5,600	(5,147)
Other income (expenses):				
Interest expense	(825)	(1,281)	(1,582)	(2,545)
Net income (loss)	$ 2,327	$ (4,182)	$ 4,018	$ (7,692)
General partner s interest in net income (loss)	$ 46	$ (84)	$ 80	$ (154)
Limited partners interest in net income (loss)	$ 2,281	$ (4,098)	$ 3,938	$ (7,538)
Limited partners net income (loss) per unit (basic) (See Note 9)	$ 0.25	$ (0.74)	$ 0.43	$ (1.36)
Weighted average number of units used in computation of limited partners net income (loss) per unit (basic)	9,107	5,525	9,100	5,546
Limited partners net income (loss) per unit (diluted) (See Note 9)	$ 0.25	$ (0.74)	$ 0.43	$ (1.36)
Weighted average number of units used in computation of limited partners net income (loss) per unit (diluted)	9,276	5,525	9,263	5,546

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

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American Midstream Partners, LP and Subsidiaries

Condensed Consolidated Statements of Comprehensive Income

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(in thousands)			
Net income (loss)	$ 2,327	$ (4,182)	$ 4,018	$ (7,692)
Unrealized gain (loss) on post retirement benefit plan assets and liabilities	14		17	
Compreshensive income (loss)	$ 2,341	$ (4,182)	$ 4,035	$ (7,692)

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

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American Midstream Partners, LP and Subsidiaries

Condensed Consolidated Statements of Changes in Partners Capital

(Unaudited)

	Limited Partner Common Units	Limited Partner Subordinated Units	Limited Partner Interest	General Partner Units	General Partner Interest	Accumulated Other Comprehensive Income	Total
				(in thousands)			
Balances at December 31, 2010	5,363		$ 83,624	109	$ 2,124	$ 56	$ 85,804
Net income (loss)			(7,538)		(154)		(7,692)
Unitholder distributions			(7,192)		(146)		(7,338)
LTIP vesting	15		318		(318)		
Unit based compensation			218		687		905
Balances at June 30, 2011	5,378		$ 69,430	109	$ 2,193	$ 56	$ 71,679
Balances at December 31, 2011	4,561	4,526	$ 99,890	185	$ 1,091	$ 415	$ 101,396
Net income (loss)			3,938		80		4,018
Unitholder contributions					13		13
Unitholder distributions			(7,870)		(161)		(8,031)
LTIP vesting	20		364		(364)		
Tax netting repurchase	(4)		(88)				(88)
Unit based compensation	5		97		701		798
Adjustments to other post retirement plan assets and liabilities						17	17
Balances at June 30, 2012	4,582	4,526	$ 96,331	185	$ 1,360	$ 432	$ 98,123

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

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American Midstream Partners, LP and Subsidiaries

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(in thousands)	
Cash flows from operating activities		
Net income (loss)	$ 4,018	$ (7,692)
Adjustments to reconcile net income (loss) to net cash provided (used) in operating activities:		
Depreciation and accretion expense	10,283	10,207
Amortization of deferred financing costs	284	389
Unrealized (gain) loss on derivative contracts	(3,494)	972
Unit based compensation	798	905
OPEB plan net periodic (benefit) cost	(41)	
(Gain) loss on sale of assets	(122)	
Changes in operating assets and liabilities:		
Accounts receivable	(55)	(760)
Unbilled revenue	5,656	847
Risk management assets		(670)
Other current assets	1,013	(418)
Other assets, net	(41)	19
Accounts payable	(160)	(267)
Accrued gas purchases	(5,264)	762
Accrued expenses and other current liabilities	(1,769)	1,614
Other liabilities	(135)	(138)
Net cash provided (used) in operating activities	10,971	5,770
Cash flows from investing activities		
Additions to property, plant and equipment	(2,384)	(2,382)
Proceeds from disposals of property, plant and equipment	122	
Funds held in escrow	(5,500)	
Net cash provided (used) in investing activities	(7,762)	(2,382)
Cash flows from financing activities		
Unit holder contributions	13	
Unit holder distributions	(8,031)	(7,338)
LTIP tax netting unit repurchase	(88)	
Payments on other loan		(381)
Deferred debt issuance costs	(926)	
Payments on long-term debt	(25,350)	(36,070)
Borrowings on long-term debt	31,340	40,400
Net cash provided (used) in financing activities	(3,042)	(3,389)
Net increase (decrease) in cash and cash equivalents	167	(1)
Cash and cash equivalents		
Beginning of period	871	63

End of period	$	1,038	$	62
Supplemental cash flow information				
Interest payments	$	1,043	$	2,327
Supplemental non-cash information				
Increase (decrease) in accrued property, plant and equipment	$	66	$	474
Receivable for reimbursable construction in progress projects	$	610	$	

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

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American Midstream Partners, LP and Subsidiaries

Notes to Condensed Consolidated Financial Statements

(Unaudited)

1. Organization and Basis of Presentation

Nature of Business

American Midstream Partners, LP (the Partnership) was formed on August 20, 2009 as a Delaware limited partnership for the purpose of acquiring and operating certain natural gas pipeline and processing businesses. We provide natural gas gathering, treating, processing, marketing, and transportation services in the Gulf Coast and Southeast regions of the United States. We hold our assets in a series of wholly owned limited liability companies as well as a limited partnership. Our capital accounts consist of general partner interests and limited partner interests.

We are controlled by our general partner, American Midstream GP, LLC, which is a wholly owned subsidiary of AIM Midstream Holdings, LLC.

Our assets are primarily located in Alabama, Louisiana, Mississippi, Tennessee, and Texas. We organize our operations into two business segments: (1) Gathering and Processing; and (2) Transmission.

Our Gathering and Processing segment is an integrated midstream natural gas system that provides gathering, compression, treating, processing, transportation, and sales of natural gas, NGLs and condensate. Our Gathering and Processing segment includes the following systems:

The Gloria gathering system provides gathering and compression services through our assets, as well as processing services through processing arrangements. The Gloria system is a Section 311 intrastate pipeline located in Lafourche, Jefferson, Plaquemines, St. Charles and St. Bernard parishes of Louisiana consisting of approximately 110 miles of pipeline with diameters ranging from 3 to 16 inches and 3 compressors with a combined size of 1,877 horsepower.

The Lafitte gathering system is a Section 311 intrastate pipeline consisting of approximately 40 miles of gathering pipeline, with diameters ranging from 4 to 12 inches. The Lafitte system originates onshore in southern Louisiana and terminates in Plaquemines Parish, Louisiana at the Alliance Refinery owned by ConocoPhillips Corporation and is connected to our Gloria gathering system.

The Bazor Ridge gathering and processing system consists of approximately 160 miles of pipeline with diameters ranging from 3 to 8 inches and 3 compressor stations with a combined compression capacity of 1,069 horsepower. Our Bazor Ridge system is located in Jasper, Clarke, Wayne and Greene Counties of Mississippi.

The Quivira gathering system consists of approximately 34 miles of pipeline, with a 12- inch diameter mainline and several laterals ranging in diameter from 6 to 8 inches. The system originates offshore of Iberia and St. Mary Parishes of Louisiana in Eugene Island Block 24 and terminates onshore at a connection with the Burns Point Plant.

The Burns Point Plant is located in St. Mary Parish, Louisiana, where raw natural gas is processed through a cryogenic processing plant that is jointly owned by us and the operator, Enterprise.

The Offshore Texas system consists of the GIGS and Brazos systems, two parallel gathering systems that share common geography and operating characteristics. The Offshore Texas system provides gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico region. The Offshore Texas system consists of approximately 56 miles of pipeline with diameters ranging from 6 to 16 inches.

The Alabama Processing system consists of 2 small skid-mounted treating and processing plants that we refer to, individually, as Atmore and Wildfork. These treating and processing plants are located in Escambia and Monroe Counties of Alabama.

The Magnolia gathering system is a Section 311 intrastate pipeline that gathers coal bed methane in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transco Pipeline system, an interstate pipeline owned by The Williams Companies, Inc. The Magnolia system consists of approximately 116 miles of pipeline with small-diameter gathering lines and trunk lines ranging from 6 to 24 inches in diameter and 1 compressor station with 3,328 horsepower.

Our other gathering and processing systems include the Fayette and Heidelberg gathering systems, located in Fayette County, Alabama and Jasper County, Mississippi, respectively.

Our Transmission segment includes intrastate and interstate pipelines that transport natural gas through Alabama, Louisiana, Mississippi and Tennessee as follows:

Our Bamagas system is a Hinshaw intrastate natural gas pipeline that travels west to east from an interconnection point with TGP in Colbert County, Alabama to 2 power plants owned by Calpine Corporation, in Morgan County, Alabama. The Bamagas system consists of 52 miles of high pressure, 30 inch pipeline.

The MLGT system is an intrastate transmission system that sources natural gas from interconnects with the FGT Pipeline system, the Tetco Pipeline system, the Transco Pipeline system and our Midla system to a Baton Rouge, Louisiana refinery owned and operated by ExxonMobil and 7 other industrial customers. Our MLGT system is comprised of approximately 54 miles of pipeline with diameters ranging from 3 to 14 inches.

Our other intrastate transmission systems include the Chalmette system, located in St. Bernard Parish, Louisiana, and the Trigas system, located in 3 counties in northwestern Alabama.

We also own a number of miscellaneous interconnects and small laterals that are collectively referred to as the SIGCO assets.

Our Midla system is a FERC regulated system that includes approximately 370 miles of interstate pipeline that runs from the Monroe gas field in northern Louisiana south through Mississippi to Baton Rouge, Louisiana.

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Our AlaTenn system is a FERC regulated system that includes approximately 295 miles of interstate pipeline that runs through the Tennessee River Valley from Selmer, Tennessee to Huntsville, Alabama and serves an 8 county area in Alabama, Mississippi and Tennessee.

Initial Public Offering

On July 26, 2011, we commenced the initial public offering of our common units pursuant to our Registration Statement on Form S-1, Commission File No. 333-173191 (the Registration Statement), which was declared effective by the SEC on July 26, 2011. Citigroup Global Markets Inc. and Merrill Lynch, Pierce, Fenner, & Smith Incorporated acted as representatives of the underwriters and as joint book-running managers of the offering.

Upon closing of our IPO on August 1, 2011, we issued 3,750,000 common units pursuant to the Registration Statement at a price per unit of $21.00. The Registration Statement registered the offer and sale of securities with a maximum aggregate offering price of $90,562,500. The aggregate offering amount of the securities sold pursuant to the Registration Statement was $78,750,000.

After deducting underwriting discounts and commissions of $4.9 million paid to the underwriters, offering expenses of $4.2 million and a structuring fee of $0.6 million, the net proceeds from our IPO were $69.1 million. We used all of the net offering proceeds from our IPO for the uses described in the final prospectus filed with the SEC pursuant to Rule 424(b) on July 27, 2011.

On July 29, 2011, in connection with the closing of our initial public offering, our general partner contributed 76,019 of our common units to us in exchange for 76,019 general partner units in order to maintain its 2.0% general partnership interest in us. This transaction was exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended.

Basis of Presentation

These unaudited consolidated financial statements have been prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements but does not include disclosures required by GAAP for annual periods. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair statement of financial position as of June 30, 2012, and December 31, 2011, results of operations for the three and six months ended June 30, 2012 and 2011, statement of partners capital for the six months ended June 30, 2012 and 2011, and statements of cash flows for the six months ended June 30, 2012 and 2011.

Our financial results for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2012. These unaudited consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2011 (Annual Report) filed on March 19, 2012.

We have made reclassifications to amounts reported in prior period consolidated financial statements to conform to our current year presentation. These reclassifications did not have an impact on net income for the period previously reported.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. We hold an undivided interest in a gas processing facility in which we are responsible for our proportionate share of the costs and expenses of the facility. Our consolidated financial statements reflect our proportionate share of the revenues, expenses, assets and liabilities of this undivided interest.

Use of Estimates

When preparing financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things (1) estimating unbilled revenues, product purchases and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Accounting for Regulated Operations

Certain of our natural gas pipelines are subject to regulations by the FERC. The FERC exercises statutory authority over matters such as construction, transportation rates we charge and our underlying accounting practices and ratemaking agreements with customers. Accordingly, we record costs that are allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a non-regulated entity. Also, we record assets and liabilities that result from the regulated ratemaking process that would be recorded under GAAP for our regulated entities. As of June 30, 2012 and 2011, we had no such material regulatory assets or liabilities.

2. Summary of Significant Accounting Policies

Funds Held for Escrow

Funds held for escrow includes restricted cash held upon the terms and subject to the conditions set forth in a sales and purchase agreement associated with the pending acquisition of an interest in a processing and fractionation plant and its related assets (see Note 15).

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Revenue Recognition and the Estimation of Revenues

We recognize revenue when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectability is reasonably assured. We record revenue and cost of product sold on a gross basis for those transactions where we act as the principal and take title to natural gas, NGLs or condensates that are purchased for resale. When our customers pay us a fee for providing a service such as gathering, treating or transportation, we record those fees separately in revenues. For the three and six months ended June 30, 2012 and 2011, respectively, we recognized the following revenues by category:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Transportation - firm	$ 2,169	$ 2,177	$ 5,472	$ 5,495
Transportation - interruptible	931	818	2,041	1,783
Sales of natural gas, NGLs and condensate	38,721	62,781	80,383	125,677
Other	1,068	254	2,382	414
Revenue	$ 42,889	$ 66,030	$ 90,278	$ 133,369

Limited Partners Net Income (Loss) Per Common Unit

We compute limited partners net income (loss) per common unit by dividing our limited partners interest in net income (loss) by the weighted average number of common units outstanding during the period. The overall computation, presentation and disclosure requirements for our limited partners net income (loss) per common unit are made in accordance with the Earnings per Share Topic of the Codification as described in the Annual Report. All per unit computations give effect to the retroactive application of the reverse unit split as described in Note 9, Partners Capital .

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11 Disclosures about Offsetting Assets and Liabilities. The ASU requires additional disclosures about the impact of offsetting, or netting, on a company s financial position, and is effective for annual periods beginning on or after January 1, 2013 and interim periods within those annual periods, and retrospectively for all comparative periods presented. Under GAAP, derivative assets and liabilities can be offset under certain conditions. The ASU requires disclosures showing both gross information and net information about instruments eligible for offset in the balance sheet. The Company is currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on our financial position or results of operations.

3. Acquisitions

Burns Point Plant Interest

On December 1, 2011, we acquired a 50% undivided interest (Interest) in the Burns Point Plant (Plant) from Marathon Oil Company (Seller) for total cash consideration of $35.5 million. No liabilities of the Seller were assumed. The purchase was effective November 1, 2011 (Effective Date) with our assumption of insurable risks, operating liabilities and entitlement to in-kind revenues as of that date. The remaining 50% undivided interest is owned by the Plant operator, Enterprise Gas Processing, LLC (Operator). The Plant, which is an unincorporated joint venture, is governed by a construction and operating agreement (Agreement).

The Plant is located in St. Mary Parish, Louisiana, and processes raw natural gas using a cryogenic expander. The Plant inlet volumes are sourced from offshore natural gas production via our Quivira system, Gulf South pipelines and onshore from individual producers near the plant. The Quivira system currently supplies approximately 88% of the inlet volume to the Plant. The residue gas is transported, via pipeline to Gulf South and Tennessee Gas Pipeline and the Y-grade liquid is transported via pipeline to K/D/S Promix, LLC (Promix), an Enterprise operated fractionator. The current capacity of the plant is 165.0 MMcf/d. The acquisition complemented our existing assets given it is the majority of the inlet volume to the Quivira system and is included in our Gathering and Processing segment.

The Plant is not a legal entity but rather an asset that is jointly owned by the Operator and us. We acquired an interest in the asset group and do not hold an interest in a legal entity. Each of the owners in the asset group is proportionately liable for the liabilities. Outside of the rights and responsibilities of the Operator, we and the Operator have equal rights and obligations to the assets. Significant non-capital and maintenance capital expenditures, plant expansions and significant plant dispositions require the approval of both owners.

Under the terms of the Agreement, the Operator is required to provide monthly production allocation and expense statements to us and is not required to prepare and provide to us balance sheet information or stand-alone financial statements. Historically, balance sheet and stand-alone financial statements for the Plant have not been prepared and are, therefore, not available.

We reviewed the governance structure of the Plant and applied the concepts discussed in ASC-810-10-45 (*Other Presentation Matters.*) We determined that while the facility is an unincorporated joint venture, the asset group is jointly controlled with the Operator.

We reviewed the requirements for the application of the equity method of accounting, given the joint control attribute of the Plant, and because the necessary complete Plant financial statements are not, nor expected to be, available from the Operator, we have elected to account for our Interest using the proportionate consolidation method. Our Interest in the Plant is recorded in property, plant and equipment, net on the consolidated balance sheet and will be depreciated over 40 years. Under this method, we include in our consolidated statement of operations the value of our Plant revenues taken in-kind and the Plant expenses reimbursed to the Operator.

4. Concentration of Credit Risk and Trade Accounts Receivable

Our primary market areas are located in the United States along the Gulf Coast and in the Southeast. We have a concentration of trade receivable balances due from companies engaged in the production, trading, distribution and marketing of natural gas and NGL products. This concentration of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. Generally, our customers historical financial and operating information is analyzed prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. We maintain allowances for potentially uncollectible accounts receivable; however, for the six months ended June 30, 2012 and period ended December 31, 2011, no allowances on or write-offs of accounts receivable were recorded.

ConocoPhillips Corporation, Enbridge Marketing (US) L.P., and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue, accounting for $13.3 million, $8.0 million, and $5.3 million, respectively, of our consolidated revenue in the consolidated statement of operations in the three months ended June 30, 2012 and $29.4 million, $17.0 million, and $11.8 million, respectively, for six months ended June 30, 2012.

ConocoPhillips Corporation, Enbridge Marketing (US) L.P., and ExxonMobil Corporation were significant customers, representing at least 10% of our consolidated revenue, accounting for $25.7 million, $10.9 million, and $10.1 million, respectively, of our consolidated revenue in the consolidated statement of operations in the three months ended June 30, 2011 and $54.5 million, $22.9 million, and $19.7 million, respectively, for the six months ended June 30, 2011.

5. Derivatives

Commodity Derivatives

To minimize the effect of commodity prices and maintain our cash flow and the economics of our development plans, we enter into commodity hedge contracts from time to time. The terms of the contracts depend on various factors, including management s view of future commodity prices, acquisition economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price downturns while allowing us to participate in some commodity price upside. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the board of directors of our general partner. Our existing commodity hedges are in the form of swaps, puts and calls.

In June 2011, the Board of Directors of our general partner determined that we would gain operational and strategic flexibility from cancelling our then-existing NGL swap contracts and entering into new NGL swap contracts with an existing counterparty that extend through the end of 2012.

In March 2012, we entered into a propane swap arrangement with an existing counterparty that extends through the end of 2013.

In May 2012, we entered into ethane, iso-butane, normal butane, and natural gasoline swap and option agreements with an existing counterparty that extend through the end of 2013.

We enter into commodity contracts with multiple counterparties. We may be required to post collateral with our counterparties in connection with our derivative positions. As of June 30, 2012, we have not posted collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparties that permit us to offset our commodity derivative asset and liability positions.

As of June 30, 2012, the aggregate notional volume of our commodity derivatives was 11.5 million NGL gallons.

As of June 30, 2012 and December 31, 2011, the fair value associated with our derivative instruments were recorded in our financial statements, under the caption Risk management assets and Risk management liabilities, as follows:

	June 30, 2012	December 31, 2011
	(in thousands)	
Risk management assets:		
Commodity derivatives	$ 2,721	$ 456

Risk management assets - long term:		
Commodity derivatives	$ 594	$
Risk management liabilities:		
Commodity derivatives	$	$ 635
Risk management liabilities - long term:		
Commodity derivatives	$	$

We recorded the following unrealized mark-to-market gains (losses) in the condensed consolidated statement of operations:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2012	**2011**	**2012**	**2011**
	(in thousands)			
Commodity derivatives	$ 3,171	$ 2,602	$ 3,494	$ (972)

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6. Fair Value Measurement

The authoritative guidance for fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include:

Level 1 unadjusted quoted prices in active markets for identical assets or liabilities;

Level 2 inputs include quoted prices for similar assets and liabilities in active markets that are either directly or indirectly observable; and

Level 3 inputs are unobservable and considered significant to fair value measurement.

A financial instrument s categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy.

We believe the carrying amount of cash and cash equivalents approximates fair value because of the short-term maturity of these instruments would be classified as Level 1 under the fair value hierarchy.

The recorded value of the amounts outstanding under the credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates and the short-term nature of borrowings and repayments under the credit facility. Our existing revolving credit facility would be classified as Level 1 under the fair value hierarchy.

The fair value of all derivatives instruments is estimated using a market valuation methodology based upon forward commodity price and volatility curves, as well as other relevant economic measures. To extrapolate a forecast of future cash flows, discount factors are utilized. The inputs are obtained from independent pricing services, and we have made no adjustments to the obtained prices.

We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivatives contracts held. We will recognize transfers between levels at the end of the reporting period for which the transfer has occurred, there were no such transfers for six months ended June 30, 2012 or period ended December 31, 2011.

Quantitative Information about Level 3 Fair Value Measurements

	Fair Value at June 30, 2012 (in thousands)	Valuation Technique	Unobservable Input	Range
Commodity derivative asset (liability), net	$ 3,315	Forecasted future cash flow	Forward NGL commodity prices	$0.884 to $1.464
			Volatility curves	20.0% to 36.0%
			Discount factors	1.047 to 1.071

The significant unobservable inputs used in the fair value measurement of the commodity derivative asset (liability) are forward commodity prices and volatility curves. Significant increases or decreases in the inputs in isolation would result in a significantly lower or higher fair value measurement.

Fair Value of Financial Instruments

The following table sets forth by level within the fair value hierarchy, our net derivative assets (liabilities) that were measured at fair value on a recurring basis as of June 30, 2012 and December 31, 2011:

	Carrying Amount	Estimated Fair Value Level 1	Level 2	Level 3	Total
		(in thousands)			
Commodity derivative asset (liability), net					
June 30, 2012	$ 3,315	$	$	$ 3,315	$ 3,315
December 31, 2011	$ (179)	$	$	$ (179)	$ (179)

Changes in Level 3 Fair Value Measurements

The table below includes a roll forward of the balance sheet amounts (including the change in fair value) for financial instruments classified by us within Level 3 of the valuation hierarchy. When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources). Contracts classified as Level 3 are valued using price inputs available from public markets to the extent that the markets are liquid or the relevant settlement periods:

	Three Months Ended June 30, 2012	2011	Six Months Ended June 30, 2012	2011
	(in thousands)			
Fair value asset (liability), beginning of period	$ 144	$ (2,904)	$ (179)	$
Realized gain (loss) on early termination of commodity derivatives		(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives	3,171	2,602	3,494	(972)
Purchases				670
Settlements		2,998		2,998
Fair value asset (liability), end of period	$ 3,315	$ (302)	$ 3,315	$ (302)

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Also included in revenue were $0.7 million and $0.3 million in realized gains (losses) for the three months ended June 30, 2012 and 2011, respectively, and $0.6 million and $0 in realized gains (losses) for the six months ended June 30, 2012 and 2011, respectively, representing our monthly swap settlements.

7. Property, Plant and Equipment

Property, plant and equipment, net, as of June 30, 2012 and December 31, 2011 were as follows:

	Useful Life	June 30, 2012	December 31, 2011
	(in years)	(in thousands)	
Land		$ 41	$ 41
Construction in progress		1,677	3,380
Buildings and improvements	4 to 40	1,439	1,490
Processing and treating plants	8 to 40	48,641	49,396
Pipelines	5 to 40	149,282	146,788
Compressors	4 to 20	8,478	7,437
Equipment	8 to 20	1,698	1,198
Computer software	5	1,539	1,500
Total property, plant and equipment		212,795	211,230
Accumulated depreciation		(51,270)	(40,999)
Property, plant and equipment, net		$ 161,525	$ 170,231

Of the gross property, plant and equipment balances at June 30, 2012 and December 31, 2011, $24.8 million and $24.0 million were related to AlaTenn and Midla, our FERC regulated interstate assets.

Asset Retirement Obligations

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO.

During the six months ended June 30, 2012 and year ended December 31, 2011, we recognized $0 and $0.9 million of AROs included in other liabilities for specific assets that we intend to retire for operational purposes.

We recorded accretion expense, which is included in depreciation expense, of less than $0.1 million and $0.3 million in our consolidated statements of operations for the three months ended June 30, 2012 and 2011, respectively, and less than $0.1 million and $0.7 million in our consolidated statements of operations for the six months ended June 30, 2012 and 2011, respectively, related to these AROs.

8. Long-Term Debt

On June 27, 2012, we amended our credit facility to increase the Commitments from an aggregate principal amount of $100 million to an aggregate principal amount of $200 million, evidenced by a credit agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Comerica Bank and Citicorp North America, Inc., as Co-Syndication Agents, BBVA Compass, as Documentation Agent, and the other financial institutions party thereto. The credit facility also provides for a $50 million dollar accordion feature. If the accordion feature were to be fully exercised, the total commitment under the existing facility would be $250 million.

The credit facility provides for a maximum borrowing equal to the lesser of (i) $200 million or (ii) 4.50 times adjusted consolidated EBITDA. We may elect to have loans under the credit facility bear interest either at a Eurodollar-based rate plus a margin ranging from 2.25% to 3.50% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 1/2 of 1% (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its prime rate , and (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.25% to 2.50% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan. For the six months ended June 30, 2012 and 2011, the weighted average interest rate on borrowings under our credit facility was approximately 3.88% and 7.70%, respectively.

Our obligations under the credit facility are secured by a first mortgage in favor of the lenders in our real property. Advances made under the credit facility are guaranteed on a senior unsecured basis by our subsidiaries (Guarantors). These guarantees are full and unconditional and joint and several among the

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Guarantors. The terms of the credit facility include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, August 1, 2016.

The credit facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the credit facility are (i) a total leverage ratio test (not to exceed 4.50 times) and a minimum interest coverage ratio test (not less than 2.50 times). We were in compliance with all of the covenants under our credit facility as of June 30, 2012.

Our outstanding borrowings under the credit facility at June 30, 2012 and December 31, 2011, respectively, were:

	June 30, 2012	**December 31, 2011**
	(in thousands)	
Revolving loan facility	$ 72,260	$ 66,270

At June 30, 2012 and December 31, 2011, letters of credit outstanding under the credit facility were $0.6 million.

In connection with our credit facility and amendments thereto, we incurred $3.4 million in debt issuance costs that are being amortized on a straight-line basis over the term of the credit facility.

9. Partners Capital

Our capital accounts are comprised of approximately 2% general partner interest and 98% limited partner interests. Our limited partners have limited rights of ownership as provided for under our partnership agreement and, as discussed below, the right to participate in our distributions. Our general partner manages our operations and participates in our distributions, including certain incentive distributions pursuant to the incentive distribution rights that are nonvoting limited partner interests held by our general partner.

On August 1, 2011, we closed our IPO of 3,750,000 common units at an offering price of $21.00 per unit. After deducting underwriting discounts and commissions of $4.9 million paid to the underwriters, estimated offering expenses of $4.2 million and a structuring fee of $0.6 million, the net proceeds from our initial public offering were $69.1 million. We used all of the net offering proceeds from our initial public offering for the uses described in the Annual Report.

Immediately prior to the closing of our IPO the following recapitalization transactions occurred:

- each common unit held by AIM Midstream Holdings reverse split into 0.485 common units, resulting in the ownership by AIM Midstream Holdings of an aggregate of 5,327,205 common units, representing an aggregate 97.1% limited partner interest in us;

- the common units held by AIM Midstream Holdings then converted into 801,139 common units and 4,526,066 subordinated units:

- each general partner unit held by our general partner reverse split into 0.485 general partner units, resulting in the ownership by our general partner of an aggregate of 108,718 general partner units, representing a 2.0% general partner interest in us;

- each common unit held by participants in our LTIP, reverse split into 0.485 common units, resulting in their ownership of an aggregate of 50,946 common units, representing an aggregate 0.9% limited partner interest in us, and each outstanding phantom unit granted to participants in our LTIP reverse split into 0.485 phantom units, resulting in their holding an aggregate of 209,824 phantom units.

In connection with the closing of our IPO and immediately following the recapitalization transactions, the following transactions also occurred:

AIM Midstream Holdings contributed 76,019 common units to our general partner as a capital contribution, and

our general partner contributed the common units contributed to it by AIM Midstream Holdings to us in exchange for 76,019 general partner units in order to maintain its 2.0% general partner interest in us.

The numbers of units outstanding were as follows:

	June 30, 2012	**December 31, 2011**
	(in thousands)	
Limited partner common units	4,582	4,561
Limited partner subordinated units	4,526	4,526
General partner units	185	185

The outstanding units noted above reflect the retroactive treatment of the reverse unit split resulting from the recapitalization described above.

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Net Income (Loss) per Limited Common and General Partner Unit

Net income (loss) is allocated to the general partner and the limited partners (common unit holders) in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income (loss) per limited partner common unit is calculated by dividing limited partners interest in net income (loss) by the weighted average number of outstanding limited partner common units during the period.

Unvested share-based payment awards that contain non-forfeitable rights to distributions (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted net income per limited partner unit.

We compute earnings per unit using the two-class method. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of our agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The two-class method does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the two-class method does not have any impact on our calculation of earnings per limited partner unit.

We determined basic and diluted net income (loss) per general partner unit and limited partner unit as follows:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2012	**2011**	**2012**	**2011**
	(In thousands except unit amounts)			
Net income (loss) attributable to general partner and limited partners	$ 2,327	$ (4,182)	$ 4,018	$ (7,692)
Weighted average general partner and limited partner units outstanding (basic) (a)	9,292	5,634	9,285	5,655
General partner and limited partner net income (loss) per unit (basic)	$ 0.25	$ (0.74)	$ 0.43	$ (1.36)
Weighted average general partner and limited partner units outstanding (diluted) (a)(b)	9,461	5,634	9,448	5,655
General partner and limited partner net income (loss) per unit (diluted)	$ 0.25	$ (0.74)	$ 0.43	$ (1.36)
Net income (loss) attributable to limited partners	$ 2,281	$ (4,098)	$ 3,938	$ (7,538)
Weighted average limited partner units outstanding (basic) (a)	9,107	5,525	9,100	5,546
Limited partners net income (loss) per unit (basic)	$ 0.25	$ (0.74)	$ 0.43	$ (1.36)
Weighted average limited partner units outstanding (diluted) (a)(b)	9,276	5,525	9,263	5,546
Limited partners net income (loss) per unit (diluted)	$ 0.25	$ (0.74)	$ 0.43	$ (1.36)
Net income (loss) attributable to general partner	$ 46	$ (84)	$ 80	$ (154)
Weighted average general partner units outstanding (basic)	185	109	185	109
General partner net income (loss) per unit (basic)	$ 0.25	$ (0.77)	$ 0.43	$ (1.41)
Weighted average general partner units outstanding (diluted) (b)	185	109	185	109
General partner net income (loss) per unit (diluted)	$ 0.25	$ (0.77)	$ 0.43	$ (1.41)

a) Gives effect to the reverse unit split.

b) Considers all unvested shares as fully vested for Dilutive EPU Calculation.

Distributions

We made distributions of $8.0 million and $7.3 million for the six months ended June 30, 2012 and 2011, respectively. We made no distributions in respect of our general partner s incentive distribution rights.

In addition to the distributions described above, in August 2011, we made a special distribution of $33.7 million to participants in our long-term incentive plan (LTIP) holding common units, AIM Midstream Holdings and our general partner.

10. Long-Term Incentive Plan

Our general partner manages our operations and activities and employs the personnel who provide support to our operations. On November 2, 2009, the board of directors of our general partner adopted a long-term incentive plan (LTIP) for its employees and consultants and directors who perform services for it or its affiliates. On May 25, 2010, the board of directors of our general partner adopted an amended and restated long-term incentive plan. At June 30, 2012 and December 31, 2011, 24,321 and 54,827 units, respectively, were available for future grant under the LTIP, giving retroactive treatment to the reverse unit split in connection with our recapitalized described in our Annual Report.

Ownership in the awards is subject to forfeiture until the vesting date. The LTIP is administered by the board of directors of our general partner. The board of directors of our general partner, at its discretion, may elect to settle such vested phantom units with a number of units equivalent to the fair market value at the date of vesting in lieu of cash. Although, our general partner has the option to settle in cash upon the vesting of phantom units, our general partner does not intend to settle these awards in cash. Although other types of awards are contemplated under the LTIP, all currently outstanding awards are phantom units without DERs.

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Generally, grants issued under the LTIP vest in increments of 25% on each of the first four anniversary dates of the date of the grant and do not contain any other restrictive conditions related to vesting other than continued employment.

Prior to our initial public offering, the fair value of the grants issued was calculated by the general partner based on several valuation models, including: a DCF model, a comparable company multiple analysis and a comparable recent transaction multiple analysis. As it relates to the DCF model, the model includes certain market assumptions related to future throughput volumes, projected fees and/or prices, expected costs of sales and direct operating costs and risk adjusted discount rates. Both the comparable company analysis and recent transaction analysis contain significant assumptions consistent with the DCF model, in addition to assumptions related to comparability, appropriateness of multiples (primarily based on adjusted EBITDA and DCF) and certain assumptions in the calculation of enterprise value.

The following table summarizes our unit-based awards for each of the periods indicated, in units:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Outstanding at beginning of period	142,552	209,824	162,860	205,864
Granted	34,560		34,560	19,414
Vested	(4,560)		(24,868)	(15,454)
Outstanding at end of period	172,552	209,824	172,552	209,824
Fair value per unit	$ 14.70 to $21.40	$ 14.70 to $19.69	$ 14.70 to $21.40	$ 14.70 to $19.69

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our units at the grant date. Compensation costs related to these awards, including amortization, for the three months ended June 30, 2012 and 2011 was $0.5 million and $0.3 million, respectively, and for the six months ended June 30, 2012 and 2011 was $0.8 million and $0.7 million, respectively, which is classified as equity compensation expense in the consolidated statement of operations and the non-cash portion in partners capital on the consolidated balance sheet.

The total fair value of vested units at the time of vesting was $0.5 million and $1.2 million for the six months ended June 30, 2012 and period ended December 31, 2011, respectively.

The total compensation cost related to unvested awards not yet recognized at June 30, 2012 and period ended December 31, 2011 was $2.6 million and $2.7 million, respectively, and the weighted average period over which this cost is expected to be recognized as of June 30, 2012 is approximately 1.8 years.

Effective July 11, 2012, our general partner adopted an amendment to the LTIP to increase the number of units available for issuance to 1,175,352. Please see Note 15 Subsequent Events.

11. Post-Employment Benefits

We sponsor a contributory postretirement plan that provides medical, dental and life insurance benefits for qualifying U.S. retired employees (referred to as the OPEB Plan).

Components of Net Periodic (Benefit) Cost recognized in the Condensed Consolidated Statements of Operations

	OPEB Plan			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			

Net Periodic (Benefit) Cost				
Service cost	$ 1		$ 2	
Interest cost	4		8	
Expected return on plan assets	(16)		(33)	
Amortization of net (gain) loss	(9)		(18)	
Net periodic (benefit) cost	$ (20)	$	$ (41)	$

Future contributions to the Plans

We expect to make contributions to the OPEB Plan for the year ending December 31, 2012 of $0.1 million.

12. Commitments and Contingencies

Environmental matters

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to natural gas pipeline and processing operations and we could, at times, be subject to environmental cleanup and enforcement actions. We attempt to manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment.

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Commitments and contractual obligations

Future non-cancelable commitments related to certain contractual obligations as of June 30, 2012 are presented below:

	Payments Due by Period (in thousands)						
	Total	2012	2013	2014	2015	2016	Thereafter
Operating leases and service contract	$ 2,372	$ 206	$ 415	$ 421	$ 398	$ 154	$ 778
Asset retirement obligation	8,105					8,105	
Total	$ 10,477	$ 206	$ 415	$ 421	$ 398	$ 8,259	$ 778

Total expenses related to operating leases, asset retirement obligations, land site leases and right-of-way agreements were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Operating leases	$ 225	$ 152	$ 439	$ 401
Asset retirement obligation	7		13	8
	$ 232	$ 152	$ 452	$ 409

Bazor Ridge Emissions Matter

In July 2011, in the course of preparing our annual filing for 2010 with the Mississippi Department of Environmental Quality (MDEQ) as required by our Title V Air Permit, we determined that we underreported to the MDEQ the SO_2 (sulfur dioxide) emissions from the Bazor Ridge plant for 2009 and 2010. In addition, we determined that certain SO_2 emissions during 2009 and 2010 exceeded the reportable quantity threshold under the federal Emergency Planning and Community Right-to-Know Act, or EPCRA, requiring notification of various governmental authorities. We did not make any such EPCRA notifications.

In July 2011, we self-reported these issues to the MDEQ and EPA Region IV. In January 2012, we met with EPA Region IV representatives, and have agreed to a settlement with respect to the EPCRA reporting issue. A Consent Agreement and Final Order was executed, which included a civil penalty of $23,010. After discussion with the MDEQ, in February 2012 we submitted an application to amend our Title V Air Permit to account for these SO_2 emissions. The MDEQ is currently processing this permit application. In December 2011, EPA Region IV performed an inspection of the plant, and they followed up with an Information Request in May 2012. American Midstream is currently responding to this Information Request.

Although these current negotiations with the MDEQ and EPA are proceeding towards completion, either agency could initiate further enforcement proceedings with respect to these matters, which could result in additional monetary sanctions and our Bazor Ridge plant could become subject to significant restrictions or limitations on its operations. If the Bazor Ridge plant were subject to any curtailment or other operational restrictions as a result of any such enforcement proceeding, or were required to incur additional capital expenditures for additional emission controls through any permitting process, the costs to us could be material. In addition, if emission levels for our Bazor Ridge plant were not properly reported by the prior owner for periods before our acquisition, it is possible, though not probable at this time, that one or both of the MDEQ and the EPA may institute enforcement actions against us and/or the prior owner, in which case we may have an obligation under our purchase agreement with the prior owner to indemnify them for any resulting losses (as defined in the purchase agreement). We cannot estimate the likelihood or financial impact from any further enforcement proceedings at this time, and therefore, we have not recorded a loss contingency as the criteria under ASC 450, Contingencies, have not been met.

Contractual Termination Benefits

Certain current and former employees of our general partner that are assigned to work for us maintain employment agreements that may provide for severance benefits subsequent to termination and upon receipt of a release and waiver from the employee. As of June 30, 2012, it is possible that we will be liable for up to approximately $250,000 in severance benefits in conjunction with an employee agreement of a former employee.

13. Related-Party Transactions

Employees of our general partner are assigned to work for us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by our general partner to American Midstream, LLC, which, in turn, charges the appropriate subsidiary. Our general partner does not record any profit or margin for the administrative and operational services charged to us. During the three months ended June 30, 2012 and 2011, administrative and operational services expenses of $2.5 million and $3.4 million, respectively, were charged to us by our general partner. During the six months ended June 30, 2012 and 2011 administrative and operational services expense of $6.2 million and $5.4 million respectively, were charged to us by our general partner and is primarily due to increased payroll costs.

Prior to our IPO, we had entered into an advisory services agreement with American Infrastructure MLP Management, L.L.C., American Infrastructure MLP PE Management, L.L.C., and American Infrastructure MLP Associates Management, L.L.C., as the advisors. The agreement provided for the payment of $0.3 million in 2010 and annual fees of $0.3 million plus annual increases in proportion to the increase in budgeted gross revenues thereafter. In exchange, the advisors agreed to provide us services in obtaining equity, debt, lease and acquisition financing, as well as providing other financial, advisory and consulting services. On August 1, 2011, and in connection with our IPO, we terminated the advisory services agreement in exchange for a one-time payment of $2.5 million. For the three and six months ended June 30, 2011, less than $0.1 million was recorded to selling, general and administrative expenses under this agreement.

14. Reporting Segments

Our operations are located in the United States and are organized into two reporting segments: (1) Gathering and Processing and (2) Transmission.

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Gathering and Processing

Our Gathering and Processing segment provides wellhead-to-market services, which include transporting raw natural gas from the wellhead through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems, to producers of natural gas and oil.

Transmission

Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, including local distribution companies, or LDCs, utilities and industrial, and commercial and power generation customers.

These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment.

The following tables set forth our segment information:

	Three Months Ended June 30,					
	2012			2011		
	Gathering and Processing	Transmission	Total	Gathering and Processing	Transmission	Total
	(in thousands)					
Revenue	$ 31,620	$ 11,269	$ 42,889	$ 49,111	$ 16,919	$ 66,030
Segment gross margin (a)	9,045	3,605	12,650	7,926	2,691	10,617
Realized gain (loss) on early termination of commodity derivatives (b)				(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives (b)	3,171		3,171	2,602		2,602
Direct operating expenses	2,402	1,125	3,527	1,684	1,421	3,105
Selling, general and administrative expenses			3,668			2,670
Transaction expenses						(7)
Equity compensation expense			467			2,184
Depreciation and accretion expense			5,124			5,170
(Gain) loss on sale of assets, net			(117)			
Interest expense			825			1,281
Net income (loss)			$ 2,327			$ (4,182)

	Six Months Ended June 30,					
	2012			2011		
	Gathering and Processing	Transmission	Total	Gathering and Processing	Transmission	Total
	(in thousands)					
Revenue	$ 65,871	$ 24,407	$ 90,278	$ 97,269	$ 36,100	$ 133,369
Segment gross margin (a)	18,463	8,366	26,829	16,167	6,836	23,003
Realized gain (loss) on early termination of commodity derivatives (b)				(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives (b)	3,494		3,494	(972)		(972)
Direct operating expenses	4,559	2,208	6,767	3,633	2,530	6,163
Selling, general and administrative expenses			6,997			4,871
Transaction expenses						281
Equity compensation expense			798			2,658
Depreciation and accretion expense			10,283			10,207

(Gain) loss on sale of assets, net	(122)	
Interest expense	1,582	2,545
Net income (loss)	$ 4,018	$ (7,692)

(a) Segment gross margin for our Gathering and Processing segment consists of total revenue less purchases of natural gas, NGLs and condensate. Segment gross margin for our Transmission segment consists of total revenue less purchases of natural gas. Gross margin consists of the sum of the segment gross margin for each segment. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow from operations as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Effective January 1, 2011, we changed our segment gross margin measure to exclude unrealized non cash mark-to-market adjustments related to our commodity derivatives. For the three and six months ended June 30, 2011, $2.6 million and $(1.0) million, respectively, in unrealized gains (losses) were excluded from our Gathering and Processing segment gross margin. Effective April 1, 2011 we changed our segment gross margin measure to exclude realized gain (loss) on early termination of commodity derivatives. For the three and six months ended June 30, 2011, $(3.0) million in unrealized gains (losses) were excluded from our Gathering and Processing segment gross margin.

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Asset information, including capital expenditures, by segment is not included in reports used by our management in their monitoring of performance and therefore is not disclosed.

For the purposes of our Gathering and Processing segment, for the three months ended June 30, 2012 and 2011, ConocoPhillips Corporation and Enbridge Marketing (US) L.P. represented significant customers, each representing more than 10% of our segment revenue for our Gathering and Processing segment. Our segment revenue derived from ConocoPhillips Corporation and Enbridge Marketing (US) L.P. represented $13.3 million and $5.9 million of segment revenue for the three months ended June 30, 2012 and $25.7 million and $7.2 million for the three months ended June 30, 2011 respectively.

For the six months ended June 30, 2012 and 2011, ConocoPhillips Corporation, Enbridge Marketing (US) L.P., and Dow Hydrocarbons and Resources represented significant customers, each representing more than 10% of our segment revenue in one or more of the periods presented in our Gathering and Processing segment. Our segment revenue derived from ConocoPhillips Corporation, Enbridge Marketing (US) L.P., and Dow Hydrocarbons and Resources represented $29.4 million, $11.6 million and $7.0 million of segment revenue for the six months ended June 30, 2012 and $54.5 million, $14.9 million, and $7.7 million for the six months ended June 30, 2011, respectively.

For the three months ended June 30, 2012 and 2011, ExxonMobil Corporation, Enbridge Marketing (US) L.P., and Calpine Corporation represented significant customers, each representing more than 10% of our segment revenue in our Transmission segment. Our segment revenue derived from ExxonMobil Corporation, Enbridge Marketing (US) L.P., and Calpine Corporation represented $5.3 million, $2.2 million, and $1.3 million of segment revenue for the three months ended June 30, 2012 and $10.1 million, $3.7 million, and $0.9 million for the three months ended June 30, 2011, respectively.

For the six months ended June 30, 2012 and 2011, ExxonMobil Corporation, Enbridge Marketing (US) L.P., and Calpine Corporation represented significant customers, each representing more than 10% of our segment revenue in our Transmission segment. Our segment revenue derived from ExxonMobil Corporation, Enbridge Marketing (US) L.P., and Calpine Corporation represented $11.8 million, $5.4 million, and $2.6 million of segment revenue for the six months ended June 30, 2012 and $19.7 million, $8.1 million, and $1.7 million for the six months ended June 30, 2011, respectively.

15. Subsequent Events

Acquisition

On July 9, 2012 we announced the closing of the acquisition of our 87.4% interest in the Chatom processing and fractionation plant and associated gathering infrastructure from affiliates of Quantum Resources Management, LLC, effective July 1, 2012. The acquisition consideration of approximately $51 million includes a credit associated with the cash flow Chatom generated between January 1, 2012, and the acquisition closing date. Chatom is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi, and consists of a 25 MMcf/d refrigeration processing plant, a 1,900 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 29-mile gas gathering system. As of the issuance of this report, the Partnership had not concluded its assessment of the fair values of assets to be acquired and liabilities to be assumed as provided in ASC 805, *Business Combinations.*

As a result of the above, on July 3, 2012 we entered into commodity option and energy swap arrangements with an existing counterparty that extend through the end of 2013 in an effort to minimize the effect of commodity prices and maintain our cash flow.

Amendment to Long-term Incentive Plan

On July 11, 2012, the board of directors of our general partner adopted a second amended and restated long-term incentive plan that will effectively increase available awards by 871,750 units.

Distribution

On July 26, 2012, we announced a distribution of $0.4325 per unit payable on August 14, 2012 to unitholders of record on August 7, 2012.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the unaudited consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report and the audited consolidated financial statements and notes thereto and management s discussion and analysis of financial condition and results of operations as of and for the year ended December 31, 2011 included in Annual Report on Form 10-K (Annual Report) that was filed with the Securities and Exchange Commission (the SEC) on March 19, 2012. This discussion contains forward-looking statements that reflect management s current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements or as a result of certain factors such as those set forth below under the caption Cautionary Statement Regarding Forward-Looking Statements.

Cautionary Statement About Forward-Looking Statements

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as may, could, project, believe, anticipate, expect, estimate, potential, plan, forecast and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. These risks and uncertainties, many of which are beyond our control, include, but are not limited to, the risks set forth in Item 1A. Risk Factors and elsewhere in this Quarterly Report, the Annual Report and the following:

our ability to access capital to fund growth including access to the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;

the amount of collateral required to be posted from time to time in our transactions;

our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;

the level of creditworthiness of counterparties to transactions;

changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;

the timing and extent of changes in natural gas, natural gas liquids and other commodity prices, interest rates and demand for our services;

weather and other natural phenomena;

- industry changes, including the impact of consolidations and changes in competition;

- our ability to obtain necessary licenses, permits and other approvals;

- the level and success of crude oil and natural gas drilling around our existing and recently acquired assets and our success in connecting natural gas supplies to our gathering and processing systems;

- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; and

- general economic, market and business conditions.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in Item 1A. Risk Factors and elsewhere in this Quarterly Report and our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

Overview

We are a growth-oriented Delaware limited partnership that was formed by affiliates of American Infrastructure MLP Fund, L.P. (AIM) in August 2009 to own, operate, develop and acquire a diversified portfolio of natural gas midstream energy assets. We are engaged in the business of gathering, treating, processing and transporting natural gas through our ownership and operation of nine gathering systems, three processing facilities, two interstate pipelines and five intrastate pipelines as of June 30, 2012. We also own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Our primary assets, which are strategically located in Alabama, Louisiana, Mississippi, Tennessee and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 1,400 miles of pipelines that gather and transport over 500 MMcf/d of natural gas.

Our operations are organized into two segments: (i) Gathering and Processing and (ii) Transmission. In our Gathering and Processing segment, we receive fee-based and fixed-margin compensation for gathering, transporting and treating natural gas. Where we provide processing services at the plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, we typically retain and sell a percentage of the residue natural gas and resulting natural gas liquids (NGLs) under POP arrangements. We own three processing facilities that produced an average of approximately 37.5 Mgal/d and 38.3 Mgal/d of gross NGLs and received approximately 13.2 Mgal/d and 12.8 Mgal/d from our 50% interest in Burns Point Plant for the three and six months ended June 30, 2012. In addition, in connection with our elective processing arrangements, we contract for processing capacity at the Toca plant operated by a subsidiary of Enterprise Products Partners L.P. (Enterprise), where we have the option to process natural gas that we purchase. Under these arrangements, we sold an average of approximately 20.4 Mgal/d and 21.8 Mgal/d of net equity NGL volumes for the three and six months ended June 30, 2012, respectively.

The Toca plant is a cryogenic processing plant with a design capacity of approximately 1.1 Bcf/d that is located in St. Bernard Parish in Louisiana. Under our POP processing contract with Enterprise, we can process raw natural gas through the Toca plant, whether for our customers or our own account. Our month-to-month contracts with producers on the Gloria and Lafitte systems, as well as our ability to purchase natural gas at the Lafitte/TGP interconnect, provide us with the flexibility to decide whether to process natural gas through the Toca plant and capture processing margins for our own account or deliver the natural gas into the interstate pipeline market at the inlet to the Toca plant. We make this decision based on the relative prices of natural gas and NGLs on a monthly basis. We refer to the flexibility built into these contracts as our elective processing arrangements.

We also receive fee-based and fixed-margin compensation in our Transmission segment primarily related to capacity reservation charges under our firm transportation contracts and the transportation of natural gas pursuant to our interruptible transportation and fixed-margin contracts.

Recent Developments

$200 Million Credit Facility

In connection with our IPO, we paid off the amounts outstanding under our $85 million credit facility (former credit facility) evidenced by our credit agreement with a syndicate of lenders, for which Comerica Bank acted as Administrative Agent, and entered into a $100 million Credit Facility evidenced by a credit agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Comerica Bank and Citicorp North America, Inc., as Co-Syndication Agents, BBVA Compass, as Documentation Agent, and the other financial institutions party thereto.

In connection with our IPO, we borrowed on the credit facility to (i) make an aggregate distribution of $27.9 million, on a pro rata basis to AIM Midstream Holdings, to participants in our LTIP holding common units and our general partner and (ii) pay fees and expenses of $2.3 million relating to our credit facility. The distribution made to AIM Midstream Holdings and our general partner was a reimbursement for certain capital expenditures incurred with respect to assets previously contributed to us.

On June 27, 2012, we amended our credit facility to increase the Commitments from an aggregate principal amount of $100 million to an aggregate principal amount of $200 million evidenced by a credit agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Comerica Bank and Citicorp North America, Inc., as Co-Syndication Agents, BBVA Compass, as Documentation Agent, and the other financial institutions party thereto. The credit facility also provides for a $50 million dollar accordion feature. If the accordion feature were to be fully exercised, the total commitment under the existing facility would be $250 million.

Subsequent Events

Acquisition

Effective July 9, 2012 we announced the closing of the acquisition of our 87.4% interest in the Chatom processing and fractionation plant and associated gathering infrastructure from affiliates of Quantum Resources Management, LLC, effective July 1, 2012. The acquisition consideration of approximately $51 million includes a credit associated with the cash flow Chatom generated between January 1, 2012, and the acquisition closing date. Chatom is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi, and consists of a 25 MMcf/d refrigeration processing plant, a 1,900 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 29-mile gas gathering system. As of the issuance of this report, the Partnership had not concluded its assessment of the fair values of assets to be acquired and liabilities to be assumed as provided in ASC 805, *Business Combinations.*

As a result of the above, on July 3, 2012 we entered into commodity option and energy swap arrangements with an existing counterparty that extend through the end of 2013 in an effort to minimize the effect of commodity prices and maintain our cash flow.

Amendment to Long-term Incentive Plan

On July 11, 2012, the board of directors of our general partner adopted a second amended and restated long-term incentive plan that will effectively increase available awards by 871,750 units.

Distribution

On July 26, 2012, we announced a distribution of $0.4325 per unit payable on August 14, 2012 to unitholders of record on August 7, 2012.

Our Operations

We manage our business and analyze and report our results of operations through two business segments:

Gathering and Processing. Our Gathering and Processing segment provides wellhead-to-market services to producers of natural gas and oil, which include transporting raw natural gas from various receipt points through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs and selling or delivering pipeline quality natural gas as well as NGLs to various markets and pipeline systems.

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Transmission. Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, which include local distribution companies (LDCs), utilities and industrial, commercial and power generation customers.

Gathering and Processing Segment

Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas we gather and process, the commercial terms in our current contract portfolio and natural gas, NGL and condensate prices. We gather and process gas primarily pursuant to the following arrangements:

Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed cash fee for gathering and processing and transporting natural gas.

Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas, we are able to lock in a fixed-margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.

Percent-of-Proceeds Arrangements (POP). Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas and NGLs at market prices. Where we provide processing services at the processing plants that we own or obtain processing services for our own account in connection with our elective processing arrangements, such as under our Toca contract, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas, such as for our interest in the Burns Point Plant. Our POP arrangements also often contain a fee-based component.

Interest in the Burns Point Plant. We account for our interest in the Burns Point Plant using the proportionate consolidation method. Under this method, we include in our consolidated statement of operations, our value of plant revenues taken in-kind and plant expenses reimbursed to the operator.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in volumes and, thus, a decrease in our fee-based and fixed-margin gross margin. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments. Under our typical POP arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our POP arrangements also often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure to commodity price risk through our hedging program. Please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk.

Transmission Segment

Results of operations from our Transmission segment are determined primarily by capacity reservation fees from firm transportation contracts and, to a lesser extent, the volumes of natural gas transported on the interstate and intrastate pipelines we own pursuant to interruptible transportation or fixed-margin contracts. Our transportation arrangements are further described below:

Firm Transportation Arrangements. Our obligation to provide firm transportation service means that we are obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the shipper utilizes the capacity. In most cases, the shipper also pays a variable use charge with respect to quantities actually transported by us.

Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper to the extent that we have available capacity. For this service the shipper pays no reservation charge but pays a variable use charge for quantities actually shipped.

Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same, undiscounted index price. We view fixed-margin arrangements to be economically equivalent to our interruptible transportation arrangements.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics include throughput volumes, gross margin and direct operating expenses on a segment basis, and adjusted EBITDA and distributable cash flow on a company-wide basis.

Throughput Volumes

In our Gathering and Processing segment, we must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our systems. Our ability to maintain or increase existing volumes of natural gas and obtain new supplies is impacted by (i) the level of work-overs or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to or near our gathering systems, (ii) our ability to compete for volumes from successful new wells in the areas in which we operate, (iii) our ability to obtain natural gas that has been released from other commitments and (iv) the volume of natural gas that we purchase from connected systems. We actively monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

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In our Transmission segment, the majority of our segment gross margin is generated by firm capacity reservation fees, as opposed to the actual throughput volumes, on our interstate and intrastate pipelines. Substantially all Transmission segment gross margin is generated under contracts with shippers, including producers, industrial companies, LDCs and marketers, for firm and interruptible natural gas transportation on our pipelines. We routinely monitor natural gas market activities in the areas served by our transmission systems to pursue new shipper opportunities.

Gross Margin and Segment Gross Margin

Gross margin and segment gross margin are metrics that we use to evaluate our performance. We define segment gross margin in our Gathering and Processing segment as revenue generated from gathering and processing operations less the cost of natural gas, NGLs and condensate purchased. Revenue includes revenue generated from fixed fees associated with the gathering and treating of natural gas and from the sale of natural gas, NGLs and condensate resulting from gathering and processing activities under fixed-margin and POP arrangements. The cost of natural gas, NGLs and condensate includes volumes of natural gas, NGLs and condensate remitted back to producers pursuant to POP arrangements and the cost of natural gas purchased for our own account, including pursuant to fixed-margin arrangements.

We define segment gross margin in our Transmission segment as revenue generated from firm and interruptible transportation agreements and fixed-margin arrangements, plus other related fees, less the cost of natural gas purchased in connection with fixed-margin arrangements. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

Effective April 1, 2011, we changed our gross margin and segment gross margin measure to exclude realized gains and losses associated with the early termination of commodity derivative contracts. For the three and six months ended June 30, 2012, there were no realized gains (losses) associated with the early termination of commodity derivative contracts.

Direct Operating Expenses

Our management seeks to maximize the profitability of our operations in part by minimizing direct operating expenses without sacrificing safety or the environment. Direct labor costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities, lost and unaccounted for gas and contract services comprise the most significant portion of our operating expenses. These expenses are relatively stable and largely independent of throughput volumes through our systems, but may fluctuate depending on the activities performed during a specific period.

Adjusted EBITDA

Adjusted EBITDA is a measure used by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to support our indebtedness and make cash distributions to our unit holders and general partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

We define adjusted EBITDA as net income, plus interest expense, income tax expense, depreciation expense, certain non-cash charges such as non-cash equity compensation, unrealized losses on commodity derivative contracts and selected charges that are unusual or non-recurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts, construction, operating and maintenance agreement (COMA) income, amortization of commodity put purchase costs, and selected gains that are unusual or non-recurring. The GAAP measure most directly comparable to adjusted EBITDA is net income.

We changed our calculation of adjusted EBITDA during 2011 to include the straight-line amortization of commodity put premiums over the life of the associated commodity put contracts. This is necessary as all unrealized commodity gains and losses, by definition, are excluded in calculating adjusted EBITDA and such premium costs would only be included in the calculation of adjusted EBITDA at the expiration of the put contract. We believe this treatment better reflects the allocation of commodity put premium costs over the benefit period of the commodity put contract. Commodity put premium amortization included in the calculation of adjusted EBITDA was $0.1 million and $0.2 million for the three and six months ended June 30, 2012. Further we made a change to the calculation to exclude COMA income from adjusted EBITDA. COMA income excluded from adjusted EBITDA for the three and six months ended June 30, 2012 was $1.0 million and $2.2 million.

Distributable Cash Flow

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit s yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder). Distributable cash flow will not reflect changes in working capital balances.

We define distributable cash flow as adjusted EBITDA plus interest income, less cash paid for interest expense, normalized integrity management costs and normalized maintenance capital expenditures.

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Note About Non-GAAP Financial Measures

Gross margin, adjusted EBITDA and distributable cash flows are all non-GAAP financial measures. Each has important limitations as an analytical tool because it excludes some, but not all, items that affect the most directly comparable GAAP financial measures. Management compensates for the limitations of these non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management s decision-making process.

You should not consider any of gross margin, adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Gross margin, adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry Our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

For a reconciliation of gross margin to net income, its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 14 to our unaudited consolidated financial statements included in Item 1. Financial Statements of this Quarterly Report.

The following tables reconcile the non-GAAP financial measures, adjusted EBITDA and distributable cash flow, used by management to their most directly comparable GAAP measures for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income (Loss)				
Net income	$ 2,327	$ (4,182)	$ 4,018	$ (7,692)
Add:				
Depreciation and accretion expense	5,124	5,170	10,283	10,207
Interest expense	825	1,281	1,582	2,545
Realized gain (loss) on early termination of commodity derivatives		2,998		2,998
Unrealized (gain) loss on commodity derivatives	(3,171)	(2,602)	(3,494)	972
Non-cash equity compensation expense	467	570	798	905
Special distribution to holders of LTIP phantom units		1,624		1,624
Transaction expenses		(7)		281
Deduct:				
COMA income	955	157	2,161	252
Straight-line amortization of put costs (1)	111	111	223	185
OPEB plan net periodic benefit (cost)	20		41	
Gain (loss) on sale of assets, net	117		122	
Adjusted EBITDA	$ 4,369	$ 4,584	$ 10,640	$ 11,403
Deduct:				
Cash interest expense (2)	$ 682	$ 1,089	$ 1,298	$ 2,156
Normalized maintenance capital (3)	875	750	1,750	1,500
Normalized integrity management (4)	375	375	750	750
Distributable Cash Flow	$ 2,437	$ 2,370	$ 6,842	$ 6,997

(1) Amounts noted represent the straight-line amortization of the cost of commodity put contracts over the life of the contract.
(2) Excludes amortization of debt issuance costs and mark-to-market adjustments related to interest rate derivatives.
(3) Amounts noted represent estimated annual maintenance capital expenditures of $3.5 million which is what we expect to be required to maintain our assets over the long term.
(4) Amounts noted represent average estimated integrity management costs over the seven year mandatory testing cycle.

General Trends and Outlook

We expect our business to continue to be affected by the key trends discussed under the caption Management s Discussion and Analysis of Financial Condition and Results of Operations General Trends and Outlook in the Annual Report.

We believe the diversity of our assets and our hedged commodity position to protect against downside commodity risk are key elements to long-term growth and sustainable distributable cash flow.

In our Gathering and Processing segment, favorable oil prices are supporting drilling activity in the liquids-rich Upper Smackover formation, which continues to benefit our Bazor Ridge system. We believe that favorable oil prices will also benefit us as we begin operating our newly acquired Chatom asset in the third quarter of 2012. In our Transmission segment, as a result of lower natural gas prices, we have seen increased interest from the industrial and utility markets in northern Alabama and southwestern Mississippi, which we believe will positively impact our AlaTenn and Midla systems.

Credit markets continue to experience near-record lows which we believe will continue through 2012, however, if monetary policy begins to tighten our interest rates on floating rate debt facilities and future offerings in the debt capital markets could be higher. An increase in financing costs may effect yield requirements of investors who invest in our common units.

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Our expectations are based on assumptions we made and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Results of Operations Combined Overview

Our distributable cash flow for the second quarter 2012 was $2.4 million, which was a decrease of less than $0.1 million from second quarter 2011. For the second quarter of 2012, gross margin increased $2.1 million from that of the second quarter 2011, from $12.7 million to $12.2 million.

The following table and discussion presents certain of our historical consolidated financial data for the periods indicated. The results of operations by segment are discussed in further detail following this combined overview.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Statement of Operations Data:				
Revenue	$ 42,889	$ 66,030	$ 90,278	$ 133,369
Realized gain (loss) on early termination of commodity derivatives		(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives	3,171	2,602	3,494	(972)
Total revenue	46,060	65,634	93,772	129,399
Operating expenses				
Purchases of natural gas, NGLs and condensate	30,239	55,413	63,449	110,366
Direct operating expenses	3,527	3,105	6,767	6,163
Selling, general and administrative expenses	3,668	2,670	6,997	4,871
Transaction expenses		(7)		281
Equity compensation expense (a)	467	2,184	798	2,658
Depreciation and accretion expense	5,124	5,170	10,283	10,207
(Gain) loss on sale of assets, net	(117)		(122)	
Total operating expenses	42,908	68,535	88,172	134,546
Operating income (loss)	3,152	(2,901)	5,600	(5,147)
Interest expense	(825)	(1,281)	(1,582)	(2,545)
Net income (loss)	$ 2,327	$ (4,182)	$ 4,018	$ (7,692)
Other Financial Data:				
Gross margin (b)	$ 12,650	$ 10,617	$ 26,829	$ 23,003
Adjusted EBITDA (c)	$ 4,369	$ 4,584	$ 10,640	$ 11,403
Distributable cash flow (d)	$ 2,437	$ 2,370	$ 6,842	$ 6,997

(a) Represents cash and non-cash costs related to our LTIP. Of these amounts, $0.5 million and $0.6 million, for the three months ended June 30, 2012 and 2011, respectively, and $0.8 million and $0.9 million, for the six months ended June 30, 2012 and 2011, respectively, were non-cash expenses.

(b) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 14 to our audited consolidated financial statements included in this Quarterly Report for a discussion of how we use gross margin to evaluate our operating performance.

(c) For a definition of adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use adjusted EBITDA to evaluate our operating performance, please read How We Evaluate Our Operations .

(d) For a definition of distributable cash flow and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use distributable cash flow to evaluate our operating performance, please read How We Evaluate Our Operations .

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011

Revenue. Our total revenue in the three months ended June 30, 2012 was $46.1 million compared to $65.6 million in the three months ended June 30, 2011. The decrease of $19.5 million was primarily due lower realized natural gas prices in both our Gathering and Processing and Transmission segments, and lower realized NGL prices in our Gathering and Processing segment. In addition:

- Natural gas prices were the primary reason for the decrease in our revenues, as our realized natural gas prices were approximately 46% lower in the second quarter of 2012 than over the same period in 2011. Realized NGL prices were approximately 22% lower in the second quarter of 2012 than the second quarter of 2011.

- We entered into a series of swap and put contracts in January 2011, swap contracts in June 2011, swap contracts in March 2012, and swap contracts in May 2012. These commodity derivative transactions had a positive net effect of $3.2 million on our revenue related to unrealized gains for the three months ended June 30, 2012. For the three months ended June 30, 2011 we recognized an unrealized valuation gain of $2.6 million related to commodity derivative contracts offset by $3.0 million for loss on early termination of commodity derivatives. For a discussion of our commodity derivative positions, please read Item 3. Quantitative and Qualitative Disclosures about Market Risk. Unrealized gain (loss) on commodity derivatives are not included in Gross Margin.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the three months ended June 30, 2012 were $30.2 million compared to $55.4 million in the three months ended June 30, 2011. This decrease of $25.2 million was primarily due lower realized natural gas prices in our Gathering and Processing and Transmission segments and lower realized NGL prices in our Gathering and Processing segment. Our natural gas purchases related to our fixed margin contracts and the allocated natural gas proceeds related to our POP agreements are based on the same indexes as the corresponding natural gas sales, so we saw a similar decrease in the price which we paid to purchase natural gas as we did to sell it. We also saw decreased NGL costs associated with the allocated proceeds of NGL revenue related to our POP agreements.

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Gross Margin. Gross margin in the three months ended June 30, 2012 was $12.7 million compared to $10.6 million in the three months ended June 30, 2011. This increase of $2.1 million was primarily due to gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011, and higher revenues associated with reimbursable projects (operating and maintenance agreement income related to construction projects reimbursed by third parties) in our Transmission segment. This increase was partially offset by lower gross margin at our owned processing plants due to lower realized NGL and natural gas prices and lower throughput volumes on several assets in our Gathering and Processing segment.

Direct Operating Expenses. Direct operating expenses in the three months ended June 30, 2012 were $3.5 million compared to $3.1 million in the three months ended June 30, 2011. This increase of $0.4 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011, offset by reduction in spending related to consulting fees and supplies.

Selling, General and Administrative Expenses. SG&A expenses in the three months ended June 30, 2012 were $3.7 million compared to $2.7 million in the three months ended June 30, 2011. This increase of $1.0 million was primarily due to increased payroll costs of $0.5 million and $0.4 million in increased costs associated with operating as a publicly traded company.

Equity Compensation Expense. Compensation expense in the three months ended June 30, 2012 was $0.5 million compared to $2.2 million in the three months ended June 30, 2011. This decrease of $1.7 million was primarily due to the elimination of Distribution Equivalent Rights, or DER, payments in the second quarter of 2011 associated with our LTIP. This increase was partially offset by a decrease in DER payments due to phantom unit vesting.

Depreciation Expense. Depreciation expense in the three months ended June 30, 2012 was $5.1 million compared to $5.2 million in the three months ended June 30, 2011. This decrease of $0.1 million was due to lower accretion expense related to our Asset Retirement Obligations, offset by partial increase for depreciation associated with capital projects placed into service during the period.

Six months ended June 30, 2012 Compared to Six months ended June 30, 2011

Revenue. Our total revenue in the six months ended June 30, 2012 was $93.8 million compared to $129.4 million in the six months ended June 30, 2011. The decrease of $35.6 million was primarily due to lower realized natural gas prices and natural gas sales volumes in both our Gathering and Processing and Transmission segments. In addition:

- Revenues were also lower due to lower realized NGL prices and NGL sales volumes in our Gathering and Processing segment. Natural gas prices were the primary reason for the decrease in our revenues, as our realized natural gas prices were approximately 39% lower in the first six months of 2012 than over the same period in 2011. Natural gas sales volumes decreased due to lower throughput and new volumes gathered and transported under transportation agreements instead of fixed margin contracts. Realized NGL prices were approximately 8% lower in the first six months of 2012 than the first six months of 2011.

- We entered into a series of swap and put contracts in January 2011, swap contracts in June 2011, swap contracts in March 2012, and swap contracts in May 2012. These commodity derivative transactions had a positive net effect of $3.5 million on our revenue related to unrealized gains for the six months ended June 30, 2012. For the six months ended June 30, 2011 we recognized an unrealized valuation loss of $1.0 million related to commodity derivative contracts. and $3.0 million for loss on early termination of commodity derivative contracts, For a discussion of our commodity derivative positions, please read Item 3. Quantitative and Qualitative Disclosures about Market Risk. Unrealized gain (loss) on commodity derivatives are not included in Gross Margin.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the six months ended June 30, 2012 were $63.4 million compared to $110.4 million in the six months ended June 30, 2011. This decrease of $47.0 million was primarily due to lower realized natural gas prices and lower natural gas purchase volumes in our Gathering and Processing and Transmission segments. Purchases of natural gas, NGLs and condensate were also lower due to lower realized NGL prices and lower NGL purchase volumes in our Gathering and Processing segment. Our natural gas purchases related to our fixed margin contracts and the allocated natural gas proceeds related to our POP agreements are based on the same indexes as the corresponding natural gas sales, so we saw a similar decrease in the price, which we paid to purchase natural gas as we did to sell it. Natural gas purchase volumes decreased due to lower throughput and new volumes gathered and transported under transportation agreements instead of fixed margin contracts. NGL costs associated with the allocated proceeds of NGL revenue related to our POP agreements also decreased as a result of lower realized NGL prices.

Gross Margin. Gross margin in the six months ended June 30, 2012 was $26.8 million compared to $23.0 million in the six months ended June 30, 2011. This increase of $3.8 million was primarily due to gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011, and higher revenues associated with reimbursable projects in our Transmission and Gathering and Processing segments. This increase was partially offset by lower gross margin at our owned processing plants due to lower realized NGL and natural gas prices and lower throughput volumes on several assets in our Gathering and Processing segment.

Direct Operating Expenses. Direct operating expenses in the six months ended June 30, 2012 were $6.8 million compared to $6.2 million in the six months ended June 30, 2011. This increase of $0.6 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011, offset by reduction in spending related to consulting fees and supplies.

Selling, General and Administrative Expenses. SG&A expenses in the six months ended June 30, 2012 were $7.0 million compared to $5.2 million in the six months ended June 30, 2011. This increase of $1.8 million was primarily due to increased payroll costs of $0.8 million and $0.7 million in increased costs associated with operating as a publicly traded company.

Equity Compensation Expense. Compensation expense in the six months ended June 30, 2012 was $0.8 million compared to $2.7 million in the six months ended June 30, 2011. This decrease of $1.9 million was primarily due to the elimination of DER payments in the second quarter of 2011 associated with our LTIP. This increase was partially offset by a decrease in DER payments due to phantom unit vesting.

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Depreciation Expense. Depreciation expense in the six months ended June 30, 2012 was $10.3 million compared to $10.2 million in the six months ended June 30, 2011. This increase of $0.1 million was due to depreciation associated with capital projects placed into service during the period, in addition to depreciation associated with our acquisition of our interest in the Burns Point processing plant, which was effective November 1, 2011, partially offset by decrease in accretion expense related to our Asset Retirement Obligations.

Results of Operations Segment Results

The table below contains key segment performance indicators related to our segment results of operations.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands except operational data)			
Segment Financial and Operating Data:				
Gathering and Processing segment				
Financial data:				
Revenue	$ 31,620	$ 49,111	$ 65,871	$ 97,269
Realized gain (loss) on early termination of commodity derivatives		(2,998)		(2,998)
Unrealized gain (loss) on commodity derivatives	3,171	2,602	3,494	(972)
Total revenue	34,791	48,715	69,365	93,299
Purchases of natural gas, NGLs and condensate	$ 22,575	$ 41,185	$ 47,408	$ 81,102
Direct operating expenses	$ 2,402	$ 1,684	$ 4,559	$ 3,633
Other financial data:				
Segment gross margin	$ 9,045	$ 7,926	$ 18,463	$ 16,167
Operating data:				
Average throughput (MMcf/d)	344.0	231.3	355.6	237.0
Average plant inlet volume (MMcf/d) (a) (b)	143.1	14.4	145.9	14.8
Average gross NGL production (Mgal/d) (a) (c)	50.7	47.9	51.1	51.5
Average realized prices:				
Natural gas ($/MMcf)	$ 2.42	$ 4.50	$ 2.58	$ 4.22
NGLs ($/gal)	$ 1.11	$ 1.42	$ 1.23	$ 1.34
Condensate ($/gal)	$ 2.51	$ 2.53	$ 2.54	$ 2.38
Transmission segment				
Financial data:				
Total revenue	$ 11,269	$ 16,919	$ 24,407	$ 36,100
Purchases of natural gas, NGLs and condensate	$ 7,664	$ 14,228	$ 16,041	$ 29,264
Direct operating expenses	$ 1,125	$ 1,421	$ 2,208	$ 2,530
Other financial data:				
Segment gross margin	$ 3,605	$ 2,691	$ 8,366	$ 6,836
Operating data:				
Average throughput (MMcf/d)	407.8	314.1	400.6	379.7
Average firm transportation - capacity reservation (MMcf/d)	661.1	661.3	711.2	711.7
Average interruptible transportation - throughput (MMcf/d)	77.4	73.0	67.0	74.7

(a) Excludes volumes and gross production under our elective processing arrangements.
(b) Includes gross plant inlet volume associated our interest in the Burns Point processing plant.
(c) Includes net NGL production associated with our interest in the Burns Point processing plant.

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011

Gathering and Processing Segment

Revenue. Segment total revenue in the three months ended June 30, 2012 was $34.8 million compared to $48.7 million in the three months ended June 30, 2011. This decrease of $13.9 million was, in part, due to due to lower realized natural gas prices and lower natural gas sales volumes, primarily on our Gloria system, due to increased fee based transportation volumes and lower overall throughput volume, in addition to:

Revenues also decreased as a result of lower NGL sales volumes associated with our elective processing arrangement on the Gloria system associated with lower throughput volumes, higher fee-based contract volumes, and increased deliveries to on-system markets as well as lower NGL production at our Bazor Ridge processing plant as work was done on the plant s gas-to-gas exchanger. Revenues were also lower as a result of lower realized NGL sales prices.

Total natural gas throughput volumes on our Gathering and Processing segment were 344.0 MMcf/d in the three months ended June 30, 2012 compared to 231.3 MMcf/d in the three months ended June 30, 2011. Natural gas inlet volumes at our owned processing plants were 143.1MMcf/d in the three months ended June 30, 2012 compared to 14.4 MMcf/d in the three months ended June 30, 2011. The natural gas throughput and inlet volume increases are primarily related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011. Gross NGL production volumes from our owned processing plants were 50.7 Mgal/d in the three months ended June 30, 2012 compared to 47.9 Mgal/d in the three months ended June 30, 2011.

NGL production volumes were slightly higher from prior year due to incremental NGL production related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011, offset in part, by lower NGL production at our Bazor Ridge gathering and processing facility. The average realized price of natural gas in the three months ended June 30, 2012 was $2.42/Mcf, compared to $4.50/Mcf in the three months ended June 30, 2011. The average realized price of NGLs in the three months ended June 30, 2012 was $1.11/gal, compared to $1.42/gal in the three months ended June 30, 2011. The average realized price of condensate in the three months ended June 30, 2012 was $2.51/gal, compared to $2.53/gal in the three months ended June 30, 2011.

We entered into a series of swap and put contracts in January 2011, swap contracts in June 2011, swap contracts in March 2012, and swap contracts in May 2012. These commodity derivative transactions had a positive net effect of $3.2 million on our revenue related to unrealized gains for the three months ended June 30, 2012. For the three months ended June 30, 2011 we recognized an unrealized valuation gain of $2.6 million related to commodity derivative contracts, offset by $3.0 million for loss on early termination of commodity derivatives. For a discussion of our commodity derivative positions, please read Item 3. Quantitative and Qualitative Disclosures about Market Risk. Unrealized gain (loss) on commodity derivatives are not included in Segment Gross Margin.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the three months ended June 30, 2012 were $22.6 million compared to $41.2 million in the three months ended June 30, 2011. This decrease of $18.6 million was primarily due to lower natural gas sales prices, which decreased natural gas costs associated with our fixed margin and POP agreements, and lower natural gas purchase volumes due to lower throughput and less volume gathered under fixed margin contracts. NGL purchase costs associated with our POP agreements at Bazor Ridge were also lower due to lower realized NGL prices and lower NGL volumes, due to repair of the plant s gas-to-gas exchanger.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2012 was $9.0 million compared to $7.9 million for the three months ended June 30, 2011. This increase of $1.1 million was primarily due to gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011. This increase was partially offset by lower gross margin at our owned processing plants, primarily Bazor Ridge, as a result of lower natural gas and NGL prices, which directly impact margins associated with our POP processing agreements, and lower throughput volumes on several of our systems, primarily our Quivira and Offshore Texas systems. Volumes on Quivira were lower as a result routine compressor maintenance at the Burns Point processing plant.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2012 were $2.4 million compared to $1.7 million for the three months ended June 30, 2011. This increase of $0.7 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011, offset by reduction in spending related to consulting fees and supplies.

Transmission Segment

Revenue. Segment total revenue for the three months ended June 30, 2012 was $11.3 million compared to $16.9 million for the three months ended June 30, 2011. This decrease of $5.6 million in revenue was primarily due to lower realized natural gas prices which negatively impacted revenues associated with our fixed margin agreements on MLGT and Midla. Total natural gas throughput on our Transmission systems for the three months ended June 30, 2012 was 407.8 MMcf/d compared to 314.1 MMcf/d in the three months ended June 30, 2011. The increase in throughput is primarily a result of higher demand on our Bamagas system and new production on a section of our Midla system. Segment revenues associated with Bamagas and Midla systems are predominately contracted as Firm Transportation in nature and therefore incremental throughput generally does not result in incremental segment revenues.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the three months ended June 30, 2012 were $7.7 million compared to $14.2 million for the three months ended June 30, 2011. This decrease of $6.5 million was primarily due to lower realized natural gas prices which resulted in lower natural gas purchase costs associated with our fixed margin agreements on MLGT and Midla.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2012 was $3.6 million compared to $2.7 million for the three months ended June 30, 2011. This increase of $0.9 million was primarily due to higher revenues from reimbursable projects and increased interruptible transport volumes on our intrastate pipelines.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2012 were $1.1 million compared to $1.4 million for the three months ended June 30, 2011, with a net decrease of $0.3 million. There were no significant changes in any individual expense type.

Six months Ended June 30, 2012 Compared to Six months Ended June 30, 2011

Gathering and Processing Segment

Revenue. Segment total revenue in the six months ended June 30, 2012 was $69.4 million compared to $93.3 million in the six months ended June 30, 2011. This decrease of $23.9 million was, in part, due to lower realized natural gas prices and lower natural gas sales volumes, primarily on our Gloria system, due to increased fee based transportation volumes and lower overall throughput volume. In addition:

Revenues also decreased as a result of lower NGL sales volumes associated with our elective processing arrangement on the Gloria system associated with lower throughput volumes, higher fee-based contract volumes, and increased deliveries to on-system markets as well as lower NGL production at our Bazor Ridge processing plant as work was done on the plant s gas-to-gas exchanger. Revenues were also lower as a result of lower realized NGL sales prices.

Total natural gas throughput volumes on our Gathering and Processing segment were 355.6 MMcf/d in the six months ended June 30, 2012 compared to 237.0 MMcf/d in the six months ended June 30, 2011. Natural gas inlet volumes at our owned processing plants were 145.9 MMcf/d in the six months ended June 30, 2012 compared to 14.8 MMcf/d in the six months ended June 30, 2011. The natural gas throughput and inlet volume increases are primarily related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011. Gross NGL production volumes from our owned processing plants were 51.1 Mgal/d in the six months ended June 30, 2012 compared to 51.5 Mgal/d in the six months ended June 30, 2011. NGL production volumes were slightly lower from prior year due to lower NGL production at our Bazor Ridge gathering and processing facility, offset in part, by an increase related to our 50% undivided interest in the Burns Point Plant, effective November 1, 2011. The average realized price of natural gas in the six months ended June 30, 2012 was $2.58/Mcf, compared to $4.22 /Mcf in the six months ended June 30, 2011. The average realized price of NGLs in the six months ended June 30, 2012 was $1.23/gal, compared to $1.34/gal in the six months ended June 30, 2011. The average realized price of condensate in the six months ended June 30, 2012 was $2.54/gal, compared to $2.38/gal in the six months ended June 30, 2011.

We entered into a series of swap and put contracts in January 2011, swap contracts in June 2011, swap contracts in March 2012, and swap contracts in May 2012. These commodity derivative transactions had a positive net effect of $3.5 million on our revenue related to unrealized gains for the six months ended June 30, 2012. For the six months ended June 30, 2011 we recognized an unrealized valuation loss of $1.0 million related to commodity derivative contracts and $3.0 million for loss on early termination of commodity derivatives. For a discussion of our commodity derivative positions, please read Item 3. Quantitative and Qualitative Disclosures about Market Risk. Unrealized gain (loss) on commodity derivatives are not included in Segment Gross Margin.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate in the six months ended June 30, 2012 were $47.4 million compared to $81.1 million in the six months ended June 30, 2011. This decrease of $33.7 million was primarily due to lower natural gas sales prices, which decreased natural gas costs associated with our fixed margin and POP agreements, and lower natural gas purchase volumes due to lower throughput and less volume gathered under fixed margin contracts. NGL purchase costs associated with our POP agreements at the Bazor Ridge system were also lower due to lower realized NGL prices and lower NGL volumes, due to maintenance of its gas-to-gas exchanger.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2012 was $18.5 million compared to $16.2 million for the six months ended June 30, 2011. This increase of $2.3 million was primarily due to the gross margin from our 50% non-operated interest in the Burns Point processing plant, which we acquired in the fourth quarter of 2011 and higher revenues associated with reimbursable projects. This increase was partially offset by lower gross margin at our owned processing plants, primarily Bazor Ridge, as a result of lower natural gas and NGL prices which directly impact margins associated with our POP processing agreements, lower elective processing volumes on our Gloria system, and lower throughput volumes on several of our systems, primarily our Quivira and Offshore Texas systems. Elective processing volumes on our Gloria system were lower as a result of higher sales volumes to on-system customers, up stream of the TOCA processing plant, and increased volumes gathered under fee based transportation agreements, under which we earn a lower margin. Volumes on Quivira were lower as a result routine compressor maintenance at the Burns Point processing plant.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2012 were $4.6 million compared to $3.6 million for the six months ended June 30, 2011. This increase of $1.0 million was primarily due to the operating costs associated with our 50% interest ownership of Burns Point effective November 1, 2011, offset by reduction in spending related to consulting fees and supplies.

Transmission Segment

Revenue. Segment total revenue for the six months ended June 30, 2012 was $24.4 million compared to $36.1 million for the six months ended June 30, 2011. This decrease of $11.7 million in revenue was primarily due to lower realized natural gas prices which negatively impacted revenues associated with our fixed margin agreements on MLGT and Midla, and the conversion of a fixed margin contract to a transportation agreement on our MLGT system . This decrease was partially offset by higher revenues from reimbursable projects. Total natural gas throughput on our Transmission systems for the six months ended June 30, 2012 was 400.6 MMcf/d compared to 379.7 MMcf/d in the six months ended June 30, 2011. The increase in throughput is primarily a result of higher demand on our Bamagas system.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the six months ended June 30, 2012 were $16.0 million compared to $29.3 million for the six months ended June 30, 2011. This decrease of $13.3 million was primarily due to lower realized natural gas prices which resulted in lower natural gas purchase costs associated with our fixed-margin agreements on MLGT and Midla, and the conversion of a fixed margin contract to a transportation agreement on our MLGT system.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2012 was $8.4 million compared to $6.8 million for the six months ended June 30, 2011. This increase of $1.6 million was primarily due to higher revenues from reimbursable projects.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2012 were $2.2 million compared to $2.5 million for the six months ended June 30, 2011, with a net decrease of $0.3 million. There were no significant changes in any individual expense type.

Liquidity and Capital Resources

Our business is capital intensive and requires significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities.

The principal indicators of our liquidity at June 30, 2012 were our cash on hand and availability under our credit facility as discussed below. As of June 30, 2012, our available liquidity was $16.9 million, comprised of cash on hand less $0.5 million and $16.4 million available under our credit facility. As of July 31, 2012, our available liquidity was $12.8 million.

In the near term, we expect our sources of liquidity to include cash generated from operations, borrowings under our credit facility and issuances of debt and equity securities. We believe that the cash generated from these sources will be sufficient to allow us to distribute the minimum quarterly distribution on all of our outstanding common and subordinated units, including the corresponding distribution on our general partner interest and meet our requirements for working capital and capital expenditures over the next 12 months.

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Working Capital

Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors.

Our working capital was $12.3 million at June 30, 2012.

Cash Flows

The following table reflects cash flows for the applicable periods:

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 10,971	$ 5,770
Investing activities	(7,762)	(2,382)
Financing activities	(3,042)	(3,389)

Six months Ended June 30, 2012 Compared to Six months Ended June 30, 2011

Operating Activities. Net cash provided by operating activities was $11.0 million for the six months ended June 30, 2012 compared to $5.8 million for the six months ended June 30, 2011. The change in cash provided by (used in) operating activities was primarily a result of the acquisition of Burns Point effective November 1, 2011. In addition, $4.5 million relates to the change in mark-to-market value of our derivatives.

Investing Activities. Net cash used in investing activities was $7.8 million for the six months ended June 30, 2012 compared to $2.4 million for the six months ended June 30, 2011. The change in cash used in investing activities was primarily a result of $5.5 million used to fund escrow for the acquisition of the Chatom Assets which closed in the third quarter of 2012 and $0.9 million related to 2012 capital projects for compressor overhauls at Bazor Ridge and Gloria, interconnections at Gloria, and replacement of gas exchanger at Bazor Ridge.

Financing Activities. Net cash used in financing activities was $3.0 million for the six months ended June 30, 2012 compared to $3.4 million for the six months ended June 30, 2011. The change in cash used in financing activities was primarily a result of a $1.7 million decrease related to debt borrowing and repayment activity in 2012 and $0.4 million decrease related to change in payments on other loans, which was paid in full during the third quarter of 2011. The decreases were offset by an increase of $0.9 million related to deferred debt issuance costs for bank and legal fees in connection with our IPO effective August 1, 2011 and $0.6 million in distributions made to our unit holders.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities. We categorize our capital expenditures as either:

maintenance capital expenditures, which are cash expenditures (including expenditures for the addition, improvement, replacement, construction, or development of existing or new capital assets) made to maintain our long-term operating income or operating capacity; or

expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the year ended December 31, 2011, our capital expenditures exclusive of our purchase of the 50% undivided interest in the Burns Point Plant totaled $6.4 million including expansion capital expenditures of $0.5 million, maintenance capital expenditures of $2.1 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $3.8 million.

For the three and six months ended June 30, 2012, our capital expenditures totaled $1.4 million and $2.4 million, including reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $0.1 million and $0.6 million, maintenance capital expenditures of $1.1 million and $1.6 million and expansion capital project expenditures of $0.1 million and $0.2 million, respectively. We anticipate that we will continue to make significant expansion capital expenditures in the future. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives. We expect that our future expansion capital expenditures will be funded primarily by borrowings under our credit facility and the issuance of debt and equity securities.

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Integrity Management

When we acquired certain operating assets, we inherited an ongoing integrity management program required under regulations of the U.S. Department of Transportation, or DOT. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle. Our current program will be completed in 2012. In connection with the acquisition of our assets from the seller we initiated a comprehensive review of the program and concluded that there were sixteen high consequence areas, or HCAs, in addition to those identified by our Predecessor (Enbridge Midcoast Energy, L.P.) that required further testing pursuant to DOT regulations. We expect to incur $0.1 million in integrity management expenses in 2012 associated with these HCAs to complete the current integrity management program.

In 2013 we will begin a new integrity management program during which we expect to incur an average of $1.5 million in integrity management expenses per year over the course of the seven-year cycle.

Because DOT regulations require integrity management activities for each HCA to be performed within seven years from when they were last performed, we expect to incur the following expenses in conjunction with the commencement of our next seven-year integrity management program cycle in 2013:

Integrity Management Expense

(in thousands)

Total	2013	2014	2015	2016	2017	2018	2019
$ 10,609	$ 2,000	$ 5,015	$ 839	$ 675	$	$	$ 2,080

Impact of Bazor Ridge Emissions Matter

In July 2011, in the course of preparing our annual filing for 2010 with the Mississippi Department of Environmental Quality (MDEQ) as required by our Title V Air Permit, we determined that we underreported to the MDEQ the SO_2 (sulfur dioxide) emissions from the Bazor Ridge plant for 2009 and 2010. In addition, we determined that certain SO_2 emissions during 2009 and 2010 exceeded the reportable quantity threshold under the federal Emergency Planning and Community Right-to-Know Act, or EPCRA, requiring notification of various governmental authorities. We did not make any such EPCRA notifications.

In July 2011, we self-reported these issues to the MDEQ and EPA Region IV. In January 2012, we met with EPA Region IV representatives, and have agreed to a settlement with respect to the EPCRA reporting issue. A Consent Agreement and Final Order was executed which included a civil penalty of $23,010. After discussion with the MDEQ, in February 2012 we submitted an application to amend our Title V Air Permit to account for these SO_2 emissions. The MDEQ is currently processing this permit application. In December 2011, EPA Region IV performed an inspection of the plant, and they followed up with an Information Request in May 2012. American Midstream is currently responding to this Information Request.

Although these current negotiations with the MDEQ and EPA are proceeding towards completion, either agency could initiate further enforcement proceedings with respect to these matters, which could result in additional monetary sanctions and our Bazor Ridge plant could become subject to significant restrictions or limitations on its operations. If the Bazor Ridge plant were subject to any curtailment or other operational restrictions as a result of any such enforcement proceeding, or were required to incur additional capital expenditures for additional emission controls through any permitting process, the costs to us could be material. In addition, if emission levels for our Bazor Ridge plant were not properly reported by the prior owner for periods before our acquisition, it is possible, though not probable at this time, that one or both of the MDEQ and the EPA may institute enforcement actions against us and/or the prior owner, in which case we may have an obligation under our purchase agreement with the prior owner to indemnify them for any resulting losses (as defined in the purchase agreement). We cannot estimate the likelihood or financial impact from any further enforcement proceedings at this time, and therefore we have not recorded a loss contingency as the criteria under ASC 450, Contingencies, has not been met.

Distributions

We intend to pay a quarterly distribution though we do not have a legal obligation to make distributions except as provided in our partnership agreement.

On August 14, 2012, we will pay a distribution for the second quarter 2012 of $0.4325 per unit, or $4.0 million.

Contractual Obligations

The table below summarizes our obligations and other commitments as of June 30, 2012.

	Payments Due by Period (in thousands)						
	Total	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**
Operating leases and service contract	2,372	$ 206	$ 415	$ 421	$ 398	$ 154	$ 778
Asset retirement obligation	8,105					8,105	
Total	$ 10,477	$ 206	$ 415	$ 421	$ 398	$ 8,259	$ 778

Critical Accounting Policies

There were no changes to our significant accounting policies from those disclosed in the Annual Report.

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11 *Disclosures about Offsetting Assets and Liabilities*. The ASU requires additional disclosures about the impact of offsetting, or netting, on a company s financial position, and is effective for annual periods beginning on or after January 1, 2013 and interim periods within those annual periods, and retrospectively for all comparative periods presented. Under GAAP, derivative assets and liabilities can be offset under certain conditions. The ASU requires disclosures showing both gross information and net information about instruments eligible for offset in the balance sheet. The Company is currently evaluating the provisions of ASU 2011-11.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The following should be read in conjunction with Quantitative and Qualitative Disclosures about Market Risk included in the Annual Report. There have been no material changes to that information. Also, see Note 5 to the unaudited consolidated financial statements for additional discussion related to derivative instruments and hedging activities.

We continually and proactively monitor our commodity exposure and compare this exposure to our stated hedging strategy. In June 2011, the Board of Directors of our general partner determined that we would gain operational and strategic flexibility from cancelling our then-existing swap contracts and entering into a new swap contract with an existing counterparty that extends through the end of 2012. We did not modify the put contracts we entered into through our January 2011 hedge transactions.

During the six months ended June 30, 2012 and 2011, we entered into various NGL swap, option, and collar arrangements.

As of June 30, 2012, we have hedged approximately 76% of our expected exposure to NGL prices in 2012.

The table below sets forth certain information regarding our NGL fixed-priced swaps as of June 30, 2012:

		Notional Volumes	Weighted Average Price ($/gal)		Fair Market Value June 30,
Commodity	**Period**	**(gal/d)**	**We Receive**	**We Pay**	**2012**
Ethane	July 2011 - Dec 2012	7,300	$ 0.57	OPIS avg	321,613
Ethane	Jan 2013 - Dec 2013	2,974	$ 0.35	OPIS avg	(6,205)
Propane	July 2011 - Dec 2012	7,050	$ 1.40	OPIS avg	709,531
Iso-Butane	July 2011 - Dec 2012	2,510	$ 1.81	OPIS avg	965,873
Iso-Butane	Jan 2013 - Dec 2013	2,257	$ 1.52	OPIS avg	189,960
Normal Butane	July 2011 - Dec 2012	3,000	$ 1.74	OPIS avg	84,923
Normal Butane	Jan 2013 - Dec 2013	2,606	$ 1.42	OPIS avg	245,706
Natural Gasoline	July 2011 - Dec 2012	5,500	$ 2.31	OPIS avg	84,947
Natural Gasoline	Jan 2013 - Dec 2013	3,928	$ 1.90	OPIS avg	531,966
Propane	Jan 2013 - Dec 2013	5,921	$ 1.34	OPIS avg	112,241
Total		43,046			$ 3,240,555

The table below sets forth certain information regarding our NGL option and collar arrangements as of June 30, 2012:

Commodity	**Period**	**Notional Volumes (gal/d)**	**Floor Strike Price ($/gal)**	**Fair Market Value June 30, 2012**
NGL basket (1)	Feb 2011 to July 2012	9,800	$ 1.29	$ 89,087
Fixed Price Collar - Ethane	Jan 2013 to Dec 2013	2,974	$ .28 to .41	(14,323)
		12,774		$ 74,764

(1) includes ethane, propane, iso-butane, normal butane, and natural gasoline. The relative weightings of the price of each component of the basket are calculated via an arithmetic formula.

Interest Rate Risk

During the six months ended June 30, 2012, we had exposure to changes in interest rates on our indebtedness associated with our credit facility. Our interest rate cap contracts that limited our interest rate exposure to 4% expired on December 2, 2011. We currently do not anticipate entering into any interest rate hedging contracts at this time, but changing market conditions may require interest rate hedging contracts to mitigate our exposure to interest rate risk.

The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will continue to tighten further, resulting in higher interest rates. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $0.3 million for the six months ended June 30, 2012.

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Item 4. Controls and Procedures

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partner s President and Chief Executive Officer (our principal executive officer) and our general partner s Senior Vice President & Chief Financial Officer (our principal financial officer), as appropriate, to allow for timely decisions regarding required disclosure. An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act of 1934 (the Exchange Act)) was performed as of June 30, 2012. This evaluation was performed by our management, with the participation of our general partner s President and Chief Executive Officer and Senior Vice President & Chief Financial Officer. Based on this evaluation, our general partner s President and Chief Executive Officer and Senior Vice President & Chief Financial Officer concluded that these disclosure controls and procedures are effective to ensure that we are able to collect, process and disclose the information we are required to disclose in the reports we file with the SEC within the required time periods.

Changes in internal control

No changes in our internal control over financial reporting occurred during the quarter ended June 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our general partner s President and Chief Executive Officer and Senior Vice President & Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this Quarterly Report on Form 10-Q as Exhibits 31.1 and 31.2. The certifications of our President and Chief Executive Officer and Senior Vice President & Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this Quarterly Report on Form 10-Q as Exhibits 32.1 and 32.2.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please read under the captions Regulation of Operations Interstate Transportation Pipeline Regulation and Environmental Matters in our Annual Report for more information.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report, careful consideration should be given to the risk factors discussed under the caption Risk Factors in the Annual Report. There have been no material changes to the risk factors previously disclosed in the Annual Report.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.2	Second Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 4, 2011).
3.3	Certificate of Formation of American Midstream GP, LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.5 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.5	First Amendment to Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 4, 2011).
10.1	Employment Agreement, dated April 2, by and between American Midstream GP, LLC and Daniel C. Campbell (incorporated by reference to Exhibit 10.1 to the Current Report in Form 8-K (Commission File No. 001-35257) filed on April 16, 2012).
10.2	Second Amendment, dated June 27, 2012, to Credit Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on July 2, 2012).
31.1*	Certification of Brian F. Bierbach, President and Chief Executive Officer of American Midstream GP, LLC, the general partner of American Midstream Partners, LP, for the June 30, 2012 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Daniel C. Campbell, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the general partner of American Midstream Partners, LP, for the June 30, 2012 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

** Submitted electronically herewith. Pursuant to Rule 406T of Regulation S-T, the interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement of prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not files for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended and otherwise are not subject to liability under those sections.

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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.

Date: August 13, 2012

AMERICAN MIDSTREAM PARTNERS, LP

By: American Midstream GP, LLC

By: /s/ Brian F. Bierbach
Name: Brian F. Bierbach
Title: President and Chief Executive Officer
(principal executive officer)

By: /s/ Daniel C. Campbell
Name: Daniel C. Campbell
Title: Senior Vice President & Chief Financial Officer
(principal financial officer)

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