UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

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

Date of Report (Date of earliest event reported): October 23, 2014

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware	**001-33303**	**65-1295427**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(IRS Employer Identification No.)

1000 Louisiana, Suite 4300
Houston, TX 77002
(Address of principal executive office and Zip Code)

(713) 584-1000
(Registrants' telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☒ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Items.

On October 20, 2014, Targa Resources Partners LP (the "Partnership" or "TRP") filed a current report on Form 8-K (the "Original Filing") in connection with the entering into of an Agreement and Plan of Merger by, among others, the Partnership and Atlas Pipeline Partners, L.P. ("APL"). The Partnership is filing this Form 8-K to provide the audited financial statements of APL and unaudited pro forma condensed combined financial statements of the Partnership, as required by Item 9.01(a) and Item 9.01(b) of Form 8-K. This information was not included in the Original Filing. The information in Exhibit 99.1 and Exhibit 99.2 are incorporated herein by reference.

Additional Information about the Proposed Transactions

In connection with the proposed transaction, Targa Resources Corp. ("TRC") will file with the U.S. Securities and Exchange Commission (the "SEC") a registration statement on Form S-4 that will include a joint proxy statement of Atlas Energy, L.P. ("ATLS") and TRC and a prospectus of TRC (the "TRC joint proxy statement/prospectus"). In connection with the proposed transaction, TRC plans to mail the definitive TRC joint proxy statement/prospectus to its shareholders, and ATLS plans to mail the definitive TRC joint proxy statement/prospectus to its unitholders.

Also in connection with the proposed transaction, Targa Resources Partners LP will file with the SEC a registration statement on Form S-4 that will include a proxy statement of APL and a prospectus of TRP (the "TRP proxy statement/prospectus"). In connection with the proposed transaction, APL plans to mail the definitive TRP proxy statement/prospectus to its unitholders.

INVESTORS, SHAREHOLDERS AND UNITHOLDERS ARE URGED TO READ THE TRC JOINT PROXY STATEMENT/PROSPECTUS, THE TRP PROXY STATEMENT/PROSPECTUS AND OTHER RELEVANT DOCUMENTS FILED OR TO BE FILED WITH THE SEC CAREFULLY AND IN THEIR ENTIRETY WHEN THEY BECOME AVAILABLE BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT TRC, TRP, ATLS AND APL, AS WELL AS THE PROPOSED TRANSACTION AND RELATED MATTERS.

This communication does not constitute an offer to sell or the solicitation of an offer to buy any securities or a solicitation of any vote or approval.

A free copy of the TRC Joint Proxy Statement/Prospectus, the TRP Proxy Statement/Prospectus and other filings containing information about TRC, TRP, ATLS and APL may be obtained at the SEC's Internet site at www.sec.gov. In addition, the documents filed with the SEC by TRC and TRP may be obtained free of charge by directing such request to: Targa Resources, Attention: Investor Relations, 1000 Louisiana, Suite 4300, Houston, Texas 77002 or emailing jneale@targaresources.com or calling (713) 584-1133. These documents may also be obtained for free from TRC's and TRP's investor relations website at www.targaresources.com. The documents filed with the SEC by ATLS may be obtained free of charge by directing such request to: Atlas Energy, L.P., Attn: Investor Relations, 1845 Walnut Street, Philadelphia, Pennsylvania 19103 or emailing InvestorRelations@atlasenergy.com. These documents may also be obtained for free from ATLS's investor relations website at www.atlasenergy.com. The documents filed with the SEC by APL may be obtained free of charge by directing such request to: Atlas Pipeline Partners, L.P., Attn: Investor Relations, 1845 Walnut Street, Philadelphia, Pennsylvania 19103 or emailing IR@atlaspipeline.com. These documents may also be obtained for free from APL's investor relations website at www.atlaspipeline.com.

Participants in the Solicitation

TRC, TRP, ATLS and APL and their respective directors, executive officers and other persons may be deemed to be participants in the solicitation of proxies from TRC, ATLS or APL shareholders or unitholders, as applicable, in respect of the proposed transaction that will be described in the TRC joint proxy statement/prospectus and TRP proxy statement/prospectus. Information regarding TRC's directors and executive officers is contained in TRC's definitive proxy statement dated April 7, 2014, which has been filed with the SEC. Information regarding directors and executive officers of TRP's general partner is contained in TRP's Annual Report on Form 10-K for the year ended December 31, 2013, which has been filed with the SEC. Information regarding directors and executive officers of ATLS's general partner is contained in ATLS's definitive proxy statement dated March 21, 2014, which has been filed with the SEC. Information regarding directors and executive officers of APL's general partner is contained in APL's Annual Report on Form 10-K for the year ended December 31, 2013, which has been filed with the SEC.

A more complete description will be available in the registration statement and the joint proxy statement/prospectus.

Cautionary Statement Regarding Forward-Looking Information

Certain statements in this release are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, including, without limitation, statements regarding the expected benefits of the proposed transactions to TRC, TRP, APL, ATLS and their unitholders or stockholders, the anticipated completion of the proposed transactions or the timing thereof, the expected future growth, dividends, distributions of the combined companies, and plans and objectives of management for future operations. All statements, other than statements of historical facts, included in this release that address activities, events or developments that TRC and TRP expect, believe or anticipate will or may occur in the future, are forward-looking statements. These forward-looking statements rely on a number of assumptions concerning future events and are subject to a number of uncertainties, factors and risks, many of which are outside TRC's and TRP's control, which could cause results to differ materially from those expected by management of TRC and TRP. Such risks and uncertainties include, but are not limited to, weather, political, economic and market conditions, including a decline in the price and market demand for natural gas, natural gas liquids and crude oil, the timing and success of business development efforts; and other uncertainties. These and other applicable uncertainties, factors and risks are described more fully in TRC's and TRP's filings with the SEC Commission, including the Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K. TRC and TRP do not undertake an obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Item 9.01 Financial Statements and Exhibits.

(a) *Financial Statements of Business Acquired*

The unaudited consolidated balance sheets and the related consolidated statements of operations, comprehensive income, changes in equity and cash flows of APL for the three months and six months ended June 30, 2014 and 2013, and the audited consolidated balance sheets as of December 31, 2013 and 2012 and the related consolidated statements of operations, comprehensive income, changes in equity and cash flows of APL for each of the three years in the period ended December 31, 2013 and the related notes thereto, are attached hereto as Exhibit 99.1.

(b) *Pro Forma Financial Information.*

The unaudited pro forma condensed consolidated balance sheet of the Partnership as of June 30, 2014, which gives effect to the merger as if it had occurred on June 30, 2014, and the unaudited pro forma condensed consolidated statements of operations for the six months ended June 30, 2014 and for the year ended December 31, 2013 and the related notes thereto, which gives effect to the merger of the Partnership and APL as if they occurred on January 1, 2013, are attached hereto as Exhibit 99.2.

(d) Exhibits.

Exhibit Number	Description
23.1	Consent of Grant Thornton LLP, Independent Registered Public Accounting Firm for Atlas Pipeline Partners, L.P.
99.1	Unaudited consolidated balance sheets and the related consolidated statements of operations, equity and cash flows of Atlas Pipeline Partners, L.P. for the three months and six months ended June 30, 2014 and 2013, and the audited consolidated balance sheets as of December 31, 2013 and 2012 and the related consolidated statements of operations, comprehensive income, equity and cash flows of Atlas Pipeline Partners, L.P. for each of the three years in the period ended December 31, 2013 and the related notes thereto.
99.2	Unaudited pro forma condensed consolidated balance sheet of Targa Resources Partners LP as of June 30, 2014, which gives effect to the merger as if it had occurred on June 30, 2014, and the unaudited pro forma condensed consolidated statements of operations for the six months ended June 30, 2014 and for the year ended December 31, 2013 and the related notes thereto, which give effect to the merger of Targa Resources Partners LP and Atlas Pipeline Partners, L.P. as if they occurred on January 1, 2013.

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.

Targa Resources Partners LP

By: Targa Resources GP LLC,
its general partner

Date: October 23, 2014

By: /s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer

EXHIBIT INDEX

Exhibit Number	Description
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99.1	Unaudited consolidated balance sheets and the related consolidated statements of operations, equity and cash flows of Atlas Pipeline Partners. L.P. for the three months and six months ended June 30, 2014 and 2013, and the audited consolidated balance sheets as of December 31, 2013 and 2012 and the related consolidated statements of operations, comprehensive income, equity and cash flows of Atlas Pipeline Partners. L.P. for each of the three years in the period ended December 31, 2013 and the related notes thereto.
99.2	Unaudited pro forma condensed consolidated balance sheet of Targa Resources Partners LP as of June 30, 2014, which gives effect to the merger as if it had occurred on June 30, 2014, and the unaudited pro forma condensed consolidated statements of operations for the six months ended June 30, 2014 and for the year ended December 31, 2013 and the related notes thereto, which give effect to the merger of Targa Resources Partners LP and Atlas Pipeline Partners. L.P. as if they occurred on January 1, 2013.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 20, 2014, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Atlas Pipeline Partners, L.P. and subsidiaries on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Targa Resources Partners LP on Form S-8 (No.333-149200), Form S-3 (No. 333-187795), and Form S-3/A (No. 333-190231).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
October 23, 2014

Exhibit 99.1

INDEX TO FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P.

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P.
UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders
Atlas Pipeline Partners, L.P.

We have audited the accompanying consolidated balance sheets of Atlas Pipeline Partners, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership’s internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 20, 2014 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 20, 2014

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,914	$ 3,398
Funds held in escrow	—	25,000
Accounts receivable	219,297	157,526
Current portion of derivative assets	174	23,077
Prepaid expenses and other	17,393	11,074
Total current assets	241,778	220,075
Property, plant and equipment, net	2,724,192	2,200,381
Goodwill	368,572	319,285
Intangible assets, net	696,271	199,360
Equity method investment in joint ventures	248,301	86,002
Long-term portion of derivative assets	2,270	7,942
Other assets, net	46,461	32,593
Total assets	$ 4,327,845	$ 3,065,638
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 524	$ 10,835
Accounts payable – affiliates	2,912	5,500
Accounts payable	79,051	59,308
Accrued liabilities	47,449	57,752
Accrued interest payable	26,737	10,399
Current portion of derivative liabilities	11,244	—
Accrued producer liabilities	152,309	109,725
Total current liabilities	320,226	253,519
Long-term portion of derivative liabilities	320	—
Long-term debt, less current portion	1,706,786	1,169,083
Deferred income taxes, net	33,290	30,258
Other long-term liabilities	7,318	6,370
Commitments and contingencies		
Equity:		
Class D convertible preferred limited partners’ interests	450,749	—
Common limited partners’ interests	1,703,778	1,507,676
General Partner’s interest	46,118	31,501
Total partners’ capital	2,200,645	1,539,177
Non-controlling interest	59,260	67,231
Total equity	2,259,905	1,606,408
Total liabilities and equity	$ 4,327,845	$ 3,065,638

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

	Years Ended December 31, 2013	2012	2011
Revenue:			
Natural gas and liquids sales	$1,959,144	$1,137,261	$1,268,195
Transportation, processing and other fees – third parties	164,874	66,287	43,464
Transportation, processing and other fees – affiliates	303	435	335
Derivative gain (loss), net	(28,764)	31,940	(20,452)
Other income, net	11,292	10,097	11,192
Total revenues	2,106,849	1,246,020	1,302,734
Costs and expenses:			
Natural gas and liquids cost of sales	1,690,382	927,946	1,047,025
Plant operating	92,271	60,480	54,686
Transportation and compression	2,256	1,618	833
General and administrative	55,856	43,406	34,551
Compensation reimbursement – affiliates	5,000	3,800	1,806
Other costs	20,005	15,069	1,040
Depreciation and amortization	168,617	90,029	77,435
Interest	89,637	41,760	31,603
Total costs and expenses	2,124,024	1,184,108	1,248,979
Equity income (loss) in joint ventures	(4,736)	6,323	5,025
Gain (loss) on asset sales and other	(1,519)	—	256,272
Goodwill impairment loss	(43,866)	—	—
Loss on early extinguishment of debt	(26,601)	—	(19,574)
Income (loss) from continuing operations before tax	(93,897)	68,235	295,478
Income tax expense (benefit)	(2,260)	176	—
Income (loss) from continuing operations	(91,637)	68,059	295,478
Discontinued operations:			
Loss on sale of discontinued operations	—	—	(81)
Loss from discontinued operations net of tax	—	—	(81)
Net Income (loss)	(91,637)	68,059	295,397
Income attributable to non-controlling interests	(6,975)	(6,010)	(6,200)
Preferred unit imputed dividend effect	(29,485)	—	—
Preferred unit dividends in kind	(23,583)	—	—
Preferred unit dividends	—	—	(389)
Net income (loss) attributable to common limited partners and the General Partner	$ (151,680)	$ 62,049	$ 288,808

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (continued)
(in thousands, except per unit data)

	Years Ended December 31,		
	2013	2012	2011
Allocation of net income (loss) attributable to:			
Common limited partner interest:			
Continuing operations	$(165,923)	$52,391	$281,449
Discontinued operations	—	—	(79)
	(165,923)	52,391	281,370
General Partner interest:			
Continuing operations	14,243	9,658	7,440
Discontinued operations	—	—	(2)
	14,243	9,658	7,438
Net income (loss) attributable to:			
Continuing operations	(151,680)	62,049	288,889
Discontinued operations	—	—	(81)
	$(151,680)	$62,049	$288,808
Net income (loss) attributable to common limited partners per unit:			
Basic:			
Continuing operations	$ (2.23)	$ 0.95	$ 5.22
Discontinued operations	—	—	—
	$ (2.23)	$ 0.95	$ 5.22
Weighted average common limited partner units (basic)	74,364	54,326	53,525
Diluted:			
Continuing operations	$ (2.23)	$ 0.95	$ 5.22
Discontinued operations	—	—	—
	$ (2.23)	$ 0.95	$ 5.22
Weighted average common limited partner units (diluted)	74,364	55,138	53,944

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Years Ended December 31,		
	2013	2012	2011
Net income (loss)	$ (91,637)	$68,059	$295,397
Other comprehensive income:			
Adjustment for realized losses on cash flow hedges reclassified to net income (loss)	—	4,390	6,834
Total other comprehensive income	—	4,390	6,834
Comprehensive income (loss)	$ (91,637)	$72,449	$302,231
Comprehensive income attributable to non-controlling interests	$ 6,975	$ 6,010	$ 6,200
Preferred unit imputed dividend effect	29,485	—	—
Preferred unit dividends in kind	23,583	—	—
Preferred unit dividends	—	—	389
Comprehensive income (loss) attributable to common limited partners and the General Partner	(151,680)	66,439	295,642
Comprehensive income (loss)	$ (91,637)	$72,449	$302,231

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(in thousands, except unit data)

	Number of Limited Partner Units		Preferred Limited Partners	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
	Preferred	Common						
Balance at January 1, 2011	8,000	53,338,010	$ 8,000	$1,057,342	$ 20,066	$ (11,224)	$ (32,537)	$1,041,647
Redemption of preferred limited partner units	(8,000)	—	(8,000)	—	—	—	—	(8,000)
Issuance of common units under incentive plans	—	308,051	—	468	—	—	—	468
Purchase and retirement of common limited partner units	—	(28,878)	—	(984)	—	—	—	(984)
Unissued common units under incentive plans	—	—	—	3,003	—	—	—	3,003
Distributions paid	—	—	(629)	(96,036)	(3,648)	—	—	(100,313)
Distributions payable	—	—	240	—	—	—	—	240
Distributions to non-controlling interests	—	—	—	—	—	—	(2,064)	(2,064)
Other comprehensive income	—	—	—	—	—	6,834	—	6,834
Net income	—	—	389	281,370	7,438	—	6,200	295,397
Balance at December 31, 2011	—	53,617,183	$ —	$1,245,163	$ 23,856	$ (4,390)	$ (28,401)	$1,236,228
Issuance of units and General Partner capital contribution	—	10,782,462	—	321,491	6,865	—	—	328,356
Issuance of common units under incentive plans	—	180,417	—	128	—	—	—	128
Purchase and retirement of common limited partner units	—	(24,052)	—	(695)	—	—	—	(695)
Unissued common units under incentive plans	—	—	—	11,421	—	—	—	11,421
Distributions paid	—	—	—	(122,223)	(8,878)	—	—	(131,101)
Contributions from non-controlling interests	—	—	—	—	—	—	182	182
Other comprehensive income	—	—	—	—	—	4,390	—	4,390
Increase in non-controlling interest related to business combination	—	—	—	—	—	—	89,440	89,440
Net income	—	—	—	52,391	9,658	—	6,010	68,059
Balance at December 31, 2012	—	64,556,010	$ —	$1,507,676	$ 31,501	$ —	$ 67,231	$1,606,408
Issuance of units and General Partner capital contribution	13,445,383	15,740,679	397,681	526,263	19,359	—	—	943,303
Issuance of common units under incentive plans	—	288,459	—	159	—	—	—	159
Unissued common units under incentive plans	—	—	—	18,984	—	—	—	18,984
Distributions paid in kind units	378,486	—	—	—	—	—	—	—
Distributions paid	—	—	—	(183,381)	(18,985)	—	—	(202,366)
Contributions from non-controlling interests	—	—	—	—	—	—	17,021	17,021
Distributions to non-controlling interests	—	—	—	—	—	—	(1,432)	(1,432)
Decrease in non-controlling interest related to business combination	—	—	—	—	—	—	(30,535)	(30,535)
Net income (loss)	—	—	53,068	(165,923)	14,243	—	6,975	(91,637)
Balance at December 31, 2013	13,823,869	80,585,148	$ 450,749	$1,703,778	$ 46,118	$ —	$ 59,260	$2,259,905

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (91,637)	$ 68,059	$ 295,397
Less: Loss from discontinued operations net of tax	—	—	(81)
Income (loss) from continuing operations	(91,637)	68,059	295,478
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	168,617	90,029	77,435
Loss on goodwill impairment	43,866	—	—
Equity (income) loss in joint ventures	4,736	(6,323)	(5,025)
Distributions received from equity method joint ventures	7,400	7,200	4,448
Non-cash compensation expense	19,344	11,635	3,274
Amortization of deferred finance costs	6,965	4,672	4,480
Loss on early extinguishment of debt	26,601	—	19,574
Loss (gain) on asset disposition	1,519	—	(256,272)
Deferred income tax expense (benefit)	(2,260)	176	—
Change in operating assets and liabilities, net of business combinations:			
Accounts receivable, prepaid expenses and other	(73,307)	(31,417)	(16,216)
Accounts payable and accrued liabilities	61,449	37,952	5,093
Accounts payable and accounts receivable – affiliates	(2,588)	2,825	(9,605)
Derivative accounts payable and receivable	40,139	(10,170)	(19,797)
Net cash provided by operating activities	210,844	174,638	102,867
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(450,560)	(373,533)	(245,426)
Cash paid for business combinations, net of cash received	(975,887)	(633,610)	(85,000)
Proceeds from preferred rights to note receivable	—	—	8,500
Investment in joint ventures	(13,366)	—	(12,250)
Net proceeds related to asset sales	—	—	403,578
Other	(3,270)	502	(1,558)
Net cash provided by (used in) continuing investing activities	(1,443,083)	(1,006,641)	67,844
Net cash provided by (used in) discontinued investing activities	—	—	(81)
Net cash provided by (used in) investing activities	$(1,443,083)	$(1,006,641)	$ 67,763

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(in thousands)

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	$ 1,267,000	$ 1,170,500	$ 1,515,500
Repayments under credit facility	(1,408,000)	(1,019,500)	(1,443,500)
Net proceeds from issuance of long term debt	1,028,092	495,374	152,366
Repayment of long-term debt	(365,822)	—	(279,557)
Payment of premium on retirement of debt	(25,581)	—	(14,342)
Payment of deferred financing costs	(929)	(4,542)	—
Payment for acquisition-based contingent consideration	(6,000)	—	—
Principal payments on capital lease	(10,750)	(2,523)	(954)
Net proceeds from issuance of common and preferred limited partner units	923,944	321,491	468
Purchase and retirement of treasury units	—	(695)	(984)
Redemption of preferred limited partner units	—	—	(8,000)
General Partner capital contributions	19,359	6,865	—
Contributions from non-controlling interest holders	17,021	182	—
Distributions to non-controlling interest holders	(1,432)	—	(2,064)
Distributions paid to common limited partners, the General Partner and preferred limited partners	(202,366)	(131,101)	(100,313)
Other	(781)	(818)	10,754
Net cash provided by financing activities	1,233,755	835,233	(170,626)
Net change in cash and cash equivalents	1,516	3,230	4
Cash and cash equivalents, beginning of period	3,398	168	164
Cash and cash equivalents, end of period	$ 4,914	$ 3,398	$ 168

See accompanying notes to consolidated financial statements

NOTE 1 – BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the "Partnership") is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States; natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and the transportation of NGLs in the southwestern region of the United States. The Partnership's operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the "Operating Partnership"), a wholly-owned subsidiary of the Partnership. At December 31, 2013, Atlas Pipeline Partners GP, LLC (the "General Partner") owned a combined 2.0% general partner interest in the consolidated operations of the Partnership, through which it manages and effectively controls both the Partnership and the Operating Partnership. The General Partner is a wholly-owned subsidiary of Atlas Energy, L.P. ("ATLS"), a publicly-traded limited partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. At December 31, 2013, the Partnership had 80,585,148 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS; and 13,823,869 Class D convertible preferred units ("Class D Preferred Units") outstanding (see Note 5).

The Partnership has revised the presentation of its consolidated statements of comprehensive income (loss) in order to more clearly distinguish the amounts of other comprehensive income (loss) attributable to each of the common unitholders, preferred unitholders, and the non-controlling interest. This change in presentation has been applied to all periods presented. The previously reported amounts of other comprehensive income (loss) attributable to the common limited partners and the General Partner did not change for any period.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Non-Controlling Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership's wholly-owned and majority-owned subsidiaries. The General Partner's interest in the Operating Partnership is reported as part of its overall 2.0% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

The Partnership's consolidated financial statements include its 95% interest in joint ventures, which individually own a 100% interest in the WestOK natural gas gathering system and processing plants and a 72.8% undivided interest in the WestTX natural gas gathering system and processing plants. These joint ventures have a $1.9 billion note receivable from the holder of the non-controlling interest in the joint ventures, which is reflected within non-controlling interests on the Partnership's consolidated balance sheets.

The Partnership's consolidated financial statements also include its 60% interest in Centrahoma Processing LLC ("Centrahoma"). The remaining 40% ownership interest is held by MarkWest Oklahoma Gas Company LLC ("MarkWest"), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE).

The Partnership consolidates 100% of these joint ventures and reflects the non-controlling interest in the joint ventures on its statements of operations. The Partnership also reflects the non-controlling interest in the net assets of the joint venture as a component of equity on its consolidated balance sheets.

The WestTX joint venture has a 72.8% undivided joint interest in the WestTX system, of which the remaining 27.2% interest is owned by Pioneer Natural Resources Company (NYSE: PXD) ("Pioneer"). Due to the ownership of the WestTX system being in the form of an undivided interest, the WestTX joint venture proportionally consolidates its 72.8% ownership interest in the assets and liabilities and operating results of the WestTX system.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as "other comprehensive income (loss)" and for the Partnership only include changes in the fair value of unsettled derivative contracts, which were previously accounted for as cash flow hedges (see Note 10). These contracts are wholly-owned by the Partnership and the related gains and losses are not shared with the non-controlling interests. The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss). During the years ended December 31, 2012 and 2011, the Partnership reclassified $4.4 million and $6.8 million, respectively, from other comprehensive income to natural gas and liquids sales within the Partnership's consolidated statements of operations. As of December 31, 2013 and 2012, all amounts had been reclassified out of accumulated other comprehensive income and the Partnership had no amounts outstanding within accumulated other comprehensive income.

Equity Method Investments

The Partnership's consolidated financial statements include its previously owned 49% non-controlling interest in Laurel Mountain Midstream, LLC joint venture ("Laurel Mountain") until it was sold in February 2011; its 20% interest in West Texas LPG Pipeline Limited Partnership ("WTLPG"); and its interests in T2 LaSalle Gathering Company L.L.C. ("T2 LaSalle"), T2 Eagle Ford Gathering Company L.L.C. ("T2 Eagle Ford"), and T2 EF Cogeneration Holdings L.L.C. ("T2 Co-Gen") (the "T2 Joint Ventures"), which were acquired as part of the acquisition of 100% of the equity interests of TEAK Midstream, LLC ("TEAK") for $974.7 million in cash, including final purchase price adjustments, less cash received (the "TEAK Acquisition") (see Notes 3 and 4). The Partnership accounts for its investments in these joint ventures under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint ventures' net income (loss) as equity income on its consolidated statements of operations. Investments in excess of the underlying net assets of equity method investees identifiable to property, plant and equipment or finite lived intangible assets are amortized over the useful life of the related assets and recorded as a reduction to equity investment on the Partnership's consolidated balance sheet with an offsetting reduction to equity income on the Partnership's consolidated statements of operations. Excess investment representing equity method goodwill is not subject to amortization and is accounted for as a component of the investment. No goodwill was recorded on the acquisition of Laurel Mountain, WTLPG, or the T2 Joint Ventures. Equity method investments are subject to impairment evaluation. The Partnership noted no indicators of impairment for its equity method investments as of December 31, 2013 or 2012.

Use of Estimates

The preparation of the Partnership's consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's consolidated financial statements, as well as the reported amounts of revenue and expense during the reporting periods. The Partnership's consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depreciation and amortization, asset impairment, the fair value of derivative instruments, the probability of forecasted transactions, the allocation of purchase price to the fair value of assets acquired and other items. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month's financial results. Management of the Partnership believes the operating results presented represent actual results in all material respects (see "–Revenue Recognition" accounting policy for further description).

Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments. Checks outstanding at the end of a period that exceed available cash balances held at the bank are considered to be book overdrafts and are reclassified to accounts payable. At December 31, 2013 and 2012, the Partnership reclassified the balance related to book overdrafts of $28.8 million and $27.6 million, respectively, from cash and cash equivalents to accounts payable on the Partnership's consolidated balance sheets.

Receivables

In evaluating the realizability of its accounts receivable, the Partnership performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by the Partnership's review of its customers' credit information. The Partnership extends credit on an unsecured basis to many of its customers. At December 31, 2013 and 2012, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

NGL Linefill

The Partnership had $14.5 million and $7.8 million of NGL linefill at December 31, 2013 and 2012, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties for which the counterparty will pay at a designated later period at a price determined by the then current market price (see Note 11).

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs which generally do not extend the useful life of an asset for two or more years through the replacement of critical components are expensed as incurred. Major renewals and improvements that generally extend the useful life of an asset for two or more years through the replacement of critical components are capitalized. The Partnership capitalizes interest on borrowed funds related to capital projects for periods during which activities are in progress to bring these projects to their intended use. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset's estimated useful life. The Partnership follows the composite method of depreciation and has determined the composite groups to be the major asset classes of its gathering, processing and treating systems. Under the composite depreciation method, any gain or loss upon disposition or retirement of pipeline, gas gathering, processing and treating components, is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership's results of operations.

Leased property and equipment meeting capital lease criteria are capitalized based on the minimum payments required under the lease and are included within property, plant and equipment on the Partnership's consolidated balance sheets (see Note 6). Obligations under capital leases are accounted for as current and noncurrent liabilities and are included within debt on the Partnership's consolidated balance sheets (see Note 13). Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets.

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or circumstances indicate the carrying amount of an asset may not be recoverable. If it is determined an asset's estimated future undiscounted cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value, if such carrying amount exceeds the fair value. The fair value measurement of a long-lived asset is based on inputs that are not observable in the market and therefore represent Level 3 inputs (see "–Fair Value of Financial Instruments"). No impairment charges were recognized for the years ended December 31, 2013, 2012 and 2011.

Asset Retirement Obligation

The Partnership performs ongoing analysis of asset removal and site restoration costs that the Partnership may be required to perform under law or contract once an asset has been permanently taken out of service. The Partnership has property, plant and equipment at locations owned by the Partnership and at sites leased or under right of way agreements. The Partnership is under no contractual obligation to remove the assets at locations it owns. In evaluating its asset retirement obligation, the Partnership reviews its lease agreements, right of way agreements, easements and permits to determine which agreements, if any, require an asset removal and restoration obligation. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted-risk-free interest rates. However, the Partnership was not able to reasonably measure the fair value of the asset retirement obligation as of December 31, 2013 or 2012 because the settlement dates were indeterminable. Any cost incurred in the future to remove assets and restore sites will be expensed as incurred.

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. Impairment testing for goodwill is done at the reporting unit level. A reporting unit is an operating segment or one level below an operating segment (also known as a component). A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available, and segment management regularly reviews the operating results of that component. The Partnership evaluates goodwill for impairment annually, on December 31 for all reporting units, except SouthTX, which will be evaluated on April 30. The Partnership also evaluates goodwill for impairment whenever events or changes in circumstances indicate it is more likely than not the fair value of a reporting unit is less than its carrying amount. The Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. If a two-step process goodwill impairment test is required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

The Partnership completed a qualitative test for goodwill for its WestOK reporting unit and determined there were no substantive changes during the current year and no indication of impairment. The Partnership completed the first step of the goodwill impairment test for its SouthOK reporting unit and determined the reporting unit exceeded its carrying amount and, therefore, the second step of the two-step goodwill impairment test was unnecessary. The Partnership completed the two step goodwill impairment test for the Gas Treating reporting unit and determined the goodwill was impaired and recorded a goodwill impairment loss of $43.9 million (see Note 7). The Partnership performed a review for triggering events for the goodwill recorded on the SouthTX reporting unit and noted there were no substantive changes. A full impairment evaluation of the goodwill recorded on the SouthTX reporting unit will be performed once final purchase price adjustments have been made and the measurement period is completed. No goodwill impairments charges were recognized for the years ended December 31, 2012 and 2011 (see Note 7).

Intangible Assets

The Partnership amortizes intangible assets with finite useful lives over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives of all intangible assets on an annual basis, on December 31, to determine if adjustments are required. The estimated useful life for the Partnership's customer contract intangible assets is based upon the approximate average length of customer contracts in existence and expected renewals at the date of acquisition. The estimated useful life for the Partnership's customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition, adjusted for management's estimate of whether these individual relationships will continue in excess or less than the average length (see Note 7).

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates. The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty, measured at fair value (see "–Fair Value of Financial Instruments"). Changes in a derivative instrument's fair value are recognized currently in the consolidated statements of operations. The Partnership no longer applies hedge accounting for its derivatives. As such, changes in fair value of these derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. Prior to discontinuance of hedge accounting, the change in the fair value of these commodity derivative instruments was recognized in accumulated other comprehensive loss within equity on the Partnership's consolidated balance sheets. Amounts in accumulated other comprehensive loss were reclassified to the Partnership's consolidated statements of operations at the time the originally hedged physical transactions affected earnings. The Partnership has reclassified all earnings out of accumulated other comprehensive loss, within equity on the Partnership's consolidated balance sheets and had no amounts in accumulated other comprehensive loss as of December 31, 2013 and 2012.

Fair Value of Financial Instruments

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

Level 1– Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 – Unobservable inputs that reflect the entity's own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

The Partnership uses a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 11). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership has a financial risk management committee (the "Financial Risk Management Committee"), which sets the policies, procedures and valuation methods utilized by the Partnership to value its derivative contracts. The Financial Risk Management Committee members include, among others, the Chief Executive Officer, the Chief Financial Officer and the Vice Chairman of the managing board of the General Partner. The Financial Risk Management Committee receives daily reports and meets on a weekly basis to review the risk management portfolio and changes in the fair value in order to determine appropriate actions.

Income Taxes

The Partnership is generally not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership's taxable income. Such taxable income may vary substantially from net income (loss) reported in the accompanying consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements as of December 31, 2013 or 2012.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2013 except for: 1) an ongoing examination by the Texas Comptroller of Public Accounts related to the Partnership's Texas Franchise Tax for franchise report years 2008 through 2011 and 2) an examination by the Internal Revenue Service related to the Partnership's corporate subsidiary APL Arkoma, Inc.'s Federal Corporate Return for the period ended December 31, 2012.

APL Arkoma, Inc. is subject to federal and state income tax. The Partnership's corporate subsidiary accounts for income taxes under the asset and liability method. Deferred income taxes are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realization of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to write down the deferred tax assets to their net realizable value. The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are generally not subject to federal and state income taxes at the Partnership level. See Note 9 for discussion of the Partnership's federal and state income tax expense (benefits) of its taxable subsidiary as well as the Partnership's net deferred income tax assets (liabilities).

Share-Based Compensation

All share-based payments to employees, including grants of employee stock options, are recognized in the financial statements based on their fair values. Share-based awards, which have a cash option, are classified as liabilities on the Partnership's consolidated balance sheets. All other share-based awards are classified as equity on the Partnership's consolidated balance sheets. Compensation expense associated with share-based payments is recognized within general and administrative expenses on the Partnership's statements of operations from the date of the grant through the date of vesting, amortized on a straight-line method. Generally, no expense is recorded for awards that do not vest due to forfeiture.

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner's and the preferred unitholders' interests. The General Partner's interest in net income (loss) is calculated on a quarterly basis based upon its 2.0% general partner interest and incentive distributions to be distributed for the quarter (see Note 5), with a priority allocation of net income to the General Partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner's and limited partners' ownership interests.

The Partnership presents net income (loss) per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights' share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management of the Partnership believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Class D Preferred Units participate in distributions with the common limited partner units according to a predetermined formula (see Note 5), thus they are considered participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution. However, the contractual terms of the Class D Preferred Units do not require the holders to share in the losses of the entity, therefore the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the Class D Preferred Units on a pro-rata basis.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership's phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 16), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award's vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. Therefore, the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net income (loss) from continuing operations and net income from discontinued operations allocated to the General Partner and common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Continuing operations:			
Net income (loss)	$ (91,637)	$68,059	$295,478
Income attributable to non-controlling interests	(6,975)	(6,010)	(6,200)
Preferred unit imputed dividend effect	(29,485)	—	—
Preferred unit dividends in kind	(23,583)	—	—
Preferred unit dividends	—	—	(389)
Net income (loss) attributable to common limited partners and the General Partner	(151,680)	62,049	288,889
General Partner's cash incentive distributions	17,646	8,583	1,666
General Partner's ownership interest	(3,403)	1,075	5,774
Net income attributable to the General Partner's ownership interests	14,243	9,658	7,440
Net income (loss) attributable to common limited partners	(165,923)	52,391	281,449
Net income attributable to participating securities – phantom units(1)	—	772	2,187
Net income attributable to participating securities – Class D Preferred Units(2)	—	—	—
Net income attributable to participating securities	—	772	2,187
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$(165,923)	$51,619	$279,262
Discontinued operations:			
Net loss	$ —	$ —	$ (81)
Net loss attributable to the General Partner's ownership interests	—	—	(2)
Net loss utilized in the calculation of net income (loss) from discontinued operations attributable to common limited partners per unit	$ —	$ —	$ (79)

(1) Net income attributable to common limited partners' ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). Net loss attributable to common limited partners' ownership interest is not allocated to approximately 1,240,000 weighted average phantom units for the year ended December 31, 2013 because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

(2) Net income attributable to common limited partners' ownership interest is allocated to the Class D Preferred Units on a pro-rata basis (weighted average Class D Preferred Units outstanding as a percentage of the sum of the weighted average Class D Preferred Units and common limited partner units outstanding). For the year ended December 31, 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 9,110,000 weighted average Class D Preferred Units because the contractual terms of the Class D Preferred Units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities.

The following table sets forth the reconciliation of the Partnership's weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Weighted average number of common limited partner units – basic	74,364	54,326	53,525
Add effect of dilutive securities – phantom units(1)	—	812	419
Add effect of convertible preferred limited partner units(2)	—	—	—
Weighted average common limited partner units – diluted	74,364	55,138	53,944

(1) For the year ended December 31, 2013, approximately 1,240,000 weighted average phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.

(2) For the year ended December 31, 2013, approximately 9,110,000 weighted average Class D Preferred Units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

Environmental Matters

The Partnership is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Partnership has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures, including legislation related to greenhouse gas emissions. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. At this time, the Partnership is unable to assess the timing and/or effect of potential liabilities related to greenhouse gas emissions or other environmental issues. The Partnership maintains insurance, which may cover, in whole or in part, certain environmental expenditures. At December 31, 2013 and 2012, the Partnership had no material environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

The Partnership has two reportable segments: Gathering and Processing; and Transportation, Treating and Other ("Transportation and Treating"). These reportable segments reflect the way the Partnership manages its operations.

The Gathering and Processing segment consists of (1) the SouthOK, SouthTX, WestOK and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma, Eagle Ford and Permian Basins; (2) the natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee; and (3) through year ending December 31, 2011, the revenues and gain on sale related to the Partnership's former 49% interest in Laurel Mountain (see Note 4). Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas.

The Transportation and Treating segment consists of the Gas Treating operations located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford; and the Partnership's 20% interest in the equity income generated by WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Contract gas treating revenues are primarily derived from monthly lease fees for use of treating facilities. Pipeline revenues are primarily derived from transportation fees.

Revenue Recognition

The Partnership's revenue primarily consists of the sale of natural gas and NGLs along with the fees earned from its gathering, processing, treating and transportation operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced NGLs, if any, off delivery points on its systems. Under other agreements, the Partnership gathers natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas and NGLs is recognized upon physical delivery. In connection with the Partnership's gathering, processing and transportation operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas and for transporting NGLs. Revenue is a function of the volume of natural gas that the Partnership gathers and processes or the volume of NGLs transported and is not directly dependent on the value of the natural gas or NGLs. However, sustained low commodity prices could result in a decline in drilling activities by producers with consequently a decline in volumes, and a corresponding decrease in fee revenue. The Partnership is also paid a separate compression fee on many of its gathering systems. The fee is dependent upon the volume of gas flowing through its compressors and the quantity of compression stages utilized to gather the gas.

POP Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this contract-type, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership effectively owns a percentage of the commodity and revenues are directly correlated to its market value. POP contracts may include a fee component, which is charged to the producer.

Fixed Recoveries. Fee-based or POP contracts sometimes include fixed recovery terms, which mean the prices paid or products returned to the producer are calculated using an agreed NGL recovery factor, regardless of the volumes of NGLs actually recovered through processing.

Keep-Whole Contracts. These contracts require the Partnership, as the processor and gatherer, to gather or purchase raw natural gas at current market rates per MMBTU. The volume and energy content of gas gathered or purchased is based on the measurement at an agreed upon location (generally at the wellhead). The BTU quantity of gas redelivered or sold at the tailgate of the Partnership's processing facility may be lower than the BTU quantity purchased at the wellhead primarily due to the NGLs extracted from the natural gas when processed through a plant. The Partnership must make up or "keep the producer whole" for this loss in BTU quantity. To offset the make-up obligation, the Partnership retains the NGLs, which are extracted, and sells them for its own account. Therefore, the Partnership bears the economic risk (the "processing margin risk") that (1) the BTU quantity of residue gas available for redelivery to the producer may be less than received from the producer; and/or (2) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under some Keep-Whole agreements are lower in BTU content and thus can meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods when the processing margin risk is uneconomic.

The Partnership accrues unbilled revenue and the related purchase costs due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership's records and management estimates of the related gathering and compression fees, which are, in turn, based upon applicable product prices. The Partnership had unbilled revenues at December 31, 2013 and 2012 of $134.9 million and $100.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Accrued Producer Liabilities

Accrued producer liabilities on the Partnership's consolidated balance sheets represent accrued purchase commitments payable to producers related to gas gathered and processed through its system under its POP and Keep-Whole contracts (see "–Revenue Recognition").

Recently Adopted Accounting Standards

In February 2013, the FASB issued Accounting Standards Update ("ASU") 2013-02, "Other Comprehensive Income (Topic 220) – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," which, among other changes, requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component and the respective line items of net income to which the amounts were reclassified. The update does not change the components of comprehensive income that must be presented. These requirements are effective for interim and annual reporting periods beginning after December 15, 2012. The Partnership began including the additional required disclosures upon the adoption of this ASU on January 1, 2013 (see "–Comprehensive Income (Loss)"). The adoption had no material impact on the Partnership's financial position or results of operations.

Recently Issued Accounting Standards

In July 2013, the FASB issued ASU 2013-11, "Income Taxes (Topic 740) –Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists," which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership applied these requirements upon the adoption of the ASU on January 1, 2014. The adoption had no material impact on the Partnership's financial position or results of operations.

NOTE 3 – ACQUISITIONS

Cardinal Midstream, LLC

On December 20, 2012, the Partnership completed the acquisition of 100% of the equity interests held by Cardinal Midstream, LLC ("Cardinal") in three wholly-owned subsidiaries for $598.9 million in cash, including final purchase price adjustments, less cash received (the "Cardinal Acquisition"). The assets of these companies, which are referred to as the Arkoma assets, include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas. The acquisition includes a 60% interest in Centrahoma Processing, LLC ("Centrahoma"). The remaining 40% ownership interest in Centrahoma is held by MarkWest Oklahoma Gas Company LLC ("MarkWest"), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE). As part of the Cardinal Acquisition, the Partnership placed $25.0 million into escrow to cover potential indemnity claims. The $25.0 million was released to the sellers in June 2013.

The Partnership funded the purchase price for the Cardinal Acquisition in part from the private placement of $175.0 million of its 6.625% senior unsecured notes due October 1, 2020 ("6.625% Senior Notes") at a premium of 3.0%, for net proceeds of $176.1 million (see Note 13); and from the sale of 10,507,033 common limited partner units in a public offering at a negotiated purchase price of $31.00 per unit, generating net proceeds of approximately $319.3 million, including the General Partner's contribution of $6.7 million to maintain its 2.0% general partner interest in the Partnership (see Note 5). The Partnership funded the remaining purchase price from its senior secured revolving credit facility (see Note 13).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. The following table presents the values assigned to the assets acquired and liabilities assumed in the Cardinal Acquisition, based on their final estimated fair values as of the date of acquisition, including the 40% non-controlling interest of Centrahoma held by MarkWest (in thousands):

Cash	$ 1,184
Accounts receivable	13,783
Prepaid expenses and other	1,289
Property, plant and equipment	246,787
Intangible assets	232,740
Goodwill	214,090
Total assets acquired	709,873
Current portion of long-term debt	(341)
Accounts payable and accrued liabilities	(14,596)
Deferred tax liability, net	(35,353)
Long-term debt, less current portion	(604)
Total liabilities acquired	(50,894)
Non-controlling interest	(58,905)
Net assets acquired	**600,074**
Less cash received	(1,184)
Net cash paid for acquisition	**$598,890**

The fair value of MarkWest's 40% non-controlling interest in Centrahoma was based upon the purchase price allocated to the 60% controlling interest the Partnership acquired using an income approach. This measurement uses significant inputs that are not observable in the market and thus represents a fair value measurement categorized within Level 3 of the fair value hierarchy. The 40% non-controlling interest in Centrahoma was reduced by a 5.0% adjustment for lack of control that market participants would consider when measuring its fair value.

Subsequent to recording the final estimated fair values of the assets acquired and liabilities assumed in the Cardinal Acquisition, the Partnership determined that a portion of goodwill recorded in connection with the acquisition was impaired (see Note 7).

TEAK Midstream, LLC

On May 7, 2013, the Partnership completed the acquisition of 100% of the equity interests of TEAK Midstream, LLC ("TEAK") for $974.7 million in cash, including final purchase price adjustments, less cash received (the "TEAK Acquisition"), including $50.0 million placed into escrow to cover potential indemnity claims. The $50.0 million in escrow was released during the three months ended December 31, 2013. The assets of these companies, which are referred to as the SouthTX assets, include the following gas gathering and processing facilities in Texas:

- the Silver Oak I plant, which is a 200 MMCFD cryogenic processing facility;
- a second 200 MMCFD cryogenic processing facility, the Silver Oak II plant, expected to be in service the second quarter of 2014;
- 265 miles of primarily 20-24 inch gathering and residue lines;
- approximately 275 miles of low pressure gathering lines;
- a 75% interest in T2 LaSalle, which owns a 62 mile, 24-inch gathering line;
- a 50% interest in T2 Eagle Ford, which owns a 45 mile 16-inch gathering pipeline; a 71 mile 24-inch gathering line; and a 50 mile residue pipeline; and
- a 50% interest in T2 Co-Gen, which owns a cogeneration facility.

As a result of the TEAK Acquisition, the Partnership has added additional gathering and processing capacity as well as fee-based cash flows from natural gas gathering and processing operations.

The Partnership funded the purchase price for the TEAK Acquisition in part from the private placement of $400.0 million of Class D Preferred Units for net proceeds of $397.7 million, plus the General Partner's contribution of $8.2 million to maintain its 2.0% general partner interest in the Partnership (see Note 5); and in part from the sale of 11,845,000 common limited partner units in a public offering for net proceeds of approximately $388.4 million, plus the General Partner's contribution of $8.3 million to maintain its 2.0% general partner interest in the Partnership (see Note 5). The Partnership funded the remaining purchase price from its senior secured revolving credit facility, and issued $400.0 million of 4.75% unsecured senior notes due November 15, 2021 ("4.75% Senior Notes") on May 10, 2013 for net proceeds of $391.2 million to reduce the level of borrowings under the revolving credit facility as part of the TEAK Acquisition (see Note 13).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. Due to the recent date of acquisition, the accounting for the business combination is based on preliminary data that remains subject to adjustment and could change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date and the changes could be material.

The following table presents the values assigned to the assets acquired and liabilities assumed in the TEAK Acquisition, based on their preliminary estimated fair values at the date of the acquisition (in thousands):

Cash	$ 8,074
Accounts receivable	11,055
Prepaid expenses and other	1,626
Property, plant and equipment	198,752
Intangible assets	450,000
Goodwill	188,859
Equity method investment in joint ventures	161,069
Total assets acquired	1,019,435
Accounts payable and accrued liabilities	(36,690)
Total liabilities acquired	(36,690)
Net assets acquired	**982,745**
Less cash received	(8,074)
Net cash paid for acquisition	**$ 974,671**

In conjunction with the issuance of the Partnership's common limited partner units associated with the acquisition, $14.3 million of transaction fees were included in the $388.4 million net proceeds recorded within common limited partners' interests on the Partnership's consolidated balance sheets. In conjunction with the issuance of the Partnership's Class D Preferred Units associated with the acquisition, $2.3 million of transaction fees were included in the $397.7 million proceeds recorded within preferred limited partner interests on the Partnership's consolidated balance sheets. In conjunction with the issuance of the 4.75% Senior Notes and an amendment of the revolving credit facility, $9.7 million of transaction fees were recorded as deferred finance costs within other assets, net on the Partnership's consolidated balance sheets. Other acquisition costs of $19.3 million associated with the TEAK Acquisition were expensed as incurred and recorded to other costs on the Partnership's consolidated statements of operations.

Revenues and net losses of $97.4 million and $14.6 million for the year ended December 31, 2013, respectively, from the acquisition date of May 7, 2013 have been included in the Partnership's consolidated financial statements related to the TEAK Acquisition, which were included in the Partnership's Gathering and Processing reportable segment. Net earnings of $1.1 million contributed from the TEAK Acquisition from April 1, 2013 (the effective date) to May 7, 2013 (the closing date) were included as a reduction to the purchase price.

The following table provides the unaudited pro forma revenue, net income, and net income per basic and diluted common unit for the years ended December 31, 2013 and 2012 as if the following had been included in operations commencing on January 1, 2012: (A)(1) the TEAK Acquisition; (2) the common unit equity offering for net proceeds of $388.4 million in April 2013; (3) the Class D Preferred Unit offering for net proceeds of $397.7 million in April 2013; (4) the General Partner's contribution of $16.5 million to maintain its 2.0% general partner interest in the Partnership; and (5) the issuance of $400.0 million of 4.75% Senior Notes for net proceeds of $391.2 million; and (B) (1) the Cardinal Acquisition; (2) the common unit equity offering for net proceeds of $319.3 million in December 2012, including General Partner contribution; (3) the $176.1 million net proceeds from the 6.625% Senior Notes; and (4) the borrowings under the Partnership's revolving credit facility (in thousands, except per unit data; unaudited):

	Years Ended December 31,	
	2013	2012
Total revenues	$2,142,962	$1,539,044
Continuing net loss after tax attributable to common limited partners and the General Partner (1)	(184,973)	(97,301)
Continuing net loss after tax attributable to common limited partner unit:		
Basic and diluted (1)	$ (2.56)	$ (1.38)

(1) Pro forma earnings for the year ended December 31, 2013 were adjusted to exclude $19.3 million of TEAK Acquisition related costs incurred and pro forma earnings for the year ended December 31, 2012 were adjusted to include these costs.

The Partnership has prepared these unaudited pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if the Partnership had completed the TEAK and Cardinal Acquisitions and financing transactions at the beginning of the periods shown above or the results that will be attained in the future.

NOTE 4 – EQUITY METHOD INVESTMENTS

Laurel Mountain

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain to Atlas Energy Resources, LLC ("Atlas Energy Resources"), a wholly-owned subsidiary of Atlas Energy, Inc ("AEI") (the "Laurel Mountain Sale") for $409.5 million in cash, net of expenses and adjustments based on capital contributions made to and distributions received from Laurel Mountain after January 1, 2011. Concurrently, AEI became a wholly-owned subsidiary of Chevron Corporation (the "Chevron Merger") and divested its interests in ATLS, resulting in the Laurel Mountain Sale being classified as a third party sale. The Partnership recognized on its consolidated statements of operations a net gain on the sale of assets of $256.3 million during the year ended December 31, 2011. Laurel Mountain is a joint venture, which owns and operates the Appalachia natural gas gathering system previously owned by the Partnership. Subsidiaries of The Williams Companies, Inc. (NYSE: WMB) ("Williams") hold the remaining 51% ownership interest. The Partnership utilized the proceeds from the sale to repay its indebtedness and for general company purposes.

The Partnership accounted for its ownership interest in Laurel Mountain under the equity method of accounting, with recognition of its ownership interest in the income of Laurel Mountain as equity income on its consolidated statements of operations. Since the Partnership accounted for its ownership as an equity investment, the Partnership did not reclassify the earnings or the gain on sale related to Laurel Mountain to discontinued operations upon the sale of its ownership interest.

The Partnership retained its preferred distribution rights with respect to an $8.5 million balance due on a note receivable from Williams. In December 2011, Williams made cash payment to the Partnership to settle the balance on the note receivable, plus accrued interest of $0.2 million.

West Texas LPG Pipeline Limited Partnership

On May 11, 2011, the Partnership acquired a 20% interest in WTLPG from Buckeye Partners, L.P. (NYSE: BPL) for $85.0 million. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by

Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest. At the acquisition date, the carrying value of the 20% interest in WTLPG exceeded the Partnership's share of the underlying net assets of WTLPG by approximately $49.9 million. The Partnership's analysis of this difference determined that it related to the fair value of property plant and equipment, which was in excess of book value. This excess will be depreciated over approximately 38 years. The Partnership recognizes its 20% interest in WTLPG as an investment in joint ventures on its consolidated balance sheets. The Partnership accounts for its ownership interest in WTLPG under the equity method of accounting, with recognition of its ownership interest in the income of WTLPG as equity income in joint ventures on its consolidated statements of operations. The Partnership incurred costs of $0.6 million during the year ended December 31, 2011, related to the acquisition of WTLPG, which are reported as other costs within the Partnership's consolidated statements of operations.

T2 Joint Ventures

On May 7, 2013, the Partnership acquired a 75% interest in T2 LaSalle, a 50% interest in T2 Eagle Ford and a 50% interest in T2 EF Co-Gen as part of the TEAK Acquisition (see Note 3). The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The Partnership accounts for its investments in the joint ventures under the equity method of accounting.

The Partnership evaluated whether the T2 Joint Ventures should be subject to consolidation. The T2 Joint Ventures do meet the qualifications of a Variable Interest Entity ("VIE"), but the Partnership does not meet the qualifications as the primary beneficiary. Even though the Partnership owns a 50% or greater interest in the T2 Joint Ventures, the Partnership does not have controlling financial interests in these entities. The Partnership shares equal management rights with TexStar Midstream Services, L.P. ("TexStar"), the investor owning the remaining interests; and TexStar is the operator of the T2 Joint Ventures. The Partnership determined that it should account for the T2 Joint Ventures under the equity method, since the Partnership does not have a controlling financial interest, but does have a significant influence. The Partnership's maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment; any additional capital contribution commitments and the Partnership's share of any approved operating expenses incurred by the VIEs.

The following table presents the value of the Partnership's equity method investments in joint ventures as of December 31, 2013 and December 31, 2012 (in thousands):

	December 31, 2013	December 31, 2012
WTLPG	$ 85,790	$ 86,002
T2 LaSalle	50,534	—
T2 Eagle Ford	97,437	—
T2 EF Co-Gen	14,540	—
Equity method investment in joint ventures	$ 248,301	$ 86,002

The following table presents the Partnership's equity income (loss) in joint ventures for each of the three years ended December 31, 2013 (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Laurel Mountain	$ —	$ —	$ 462
WTLPG	4,988	6,323	4,563
T2 LaSalle	(3,127)	—	—
T2 Eagle Ford	(4,408)	—	—
T2 EF Co-Gen	(2,189)	—	—
Equity income (loss) in joint ventures	$(4,736)	$6,323	$5,025

NOTE 5 – EQUITY

Common Units

In November 2012, the Partnership entered into an equity distribution program with Citigroup Global Markets, Inc. ("Citigroup"). Pursuant to this program, the Partnership offered and sold through Citigroup, as its sales agent, common units for $150.0 million. Sales were at market prices prevailing at the time of the sale. During the years ended December 31, 2013 and 2012, the Partnership issued 3,895,679 and 275,429 common units, respectively, under the equity distribution program for net proceeds of $137.8 million and $8.7 million, respectively, net of $2.8 million and $0.2 million, respectively, in commissions incurred from Citigroup, and other expenses. The Partnership also received capital contributions from the General Partner of $2.9 million and $0.2 million during the years ended December 31, 2013 and 2012, respectively, to maintain its 2.0% general partner interest in the Partnership. The net proceeds from the common unit offering were utilized for general partnership purposes. As of December 31, 2013, the Partnership had used the full capacity under the equity distribution program.

In December 2012, the Partnership sold 10,507,033 common units in a public offering at a price of $31.00 per unit, yielding net proceeds of approximately $319.3 million, including $6.7 million contributed by the General Partner to maintain its 2.0% general partner interest. The Partnership utilized the net proceeds from the common unit offering to partially finance the Cardinal Acquisition (see Note 3).

In April 2013, the Partnership sold 11,845,000 common units in a public offering at a price of $34.00 per unit, yielding net proceeds of $388.4 million after underwriting commissions and expenses. The Partnership also received a capital contribution from the General Partner of $8.3 million to maintain its 2.0% general partnership interest. The Partnership used the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition (see Note 3).

Cash Distributions

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders (subject to the rights of any other class or series of the Partnership's securities with the right to share in the Partnership's cash distributions) and to the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels, including the General Partner's 2.0% interest. The General Partner, which holds all the incentive distribution rights in the Partnership, has agreed to allocate up to $3.75 million of its incentive distribution rights per quarter back to the Partnership after the General Partner receives the initial $7.0 million per quarter of incentive distribution rights.

Common unit and General Partner distributions declared by the Partnership for quarters ending from December 31, 2010 through September 30, 2013 were as follows:

For Quarter Ended	Date Cash Distribution Paid	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
December 31, 2010	February 14, 2011	$ 0.37	$ 19,735	$ 398
March 31, 2011	May 13, 2011	0.40	21,400	439
June 30, 2011	August 12, 2011	0.47	25,184	967
September 30, 2011	November 14, 2011	0.54	28,953	1,844
December 31, 2011	February 14, 2012	0.55	29,489	2,031
March 31, 2012	May 15, 2012	0.56	30,030	2,217
June 30, 2012	August 14, 2012	0.56	30,085	2,221
September 30, 2012	November 14, 2012	0.57	30,641	2,409
December 31, 2012	February 14, 2013	0.58	37,442	3,117
March 31, 2013	May 15, 2013	0.59	45,382	3,980
June 30, 2013	August 14, 2013	0.62	48,165	5,875
September 30, 2013	November 14, 2013	0.62	49,298	6,013

On January 28, 2014, the Partnership declared a cash distribution of $0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. The $56.1 million distribution, including $6.1 million to the General Partner for its general partner interest and incentive distribution rights, was paid on February 14, 2014 to unitholders of record at the close of business on February 7, 2014.

Class C Preferred Units

On February 17, 2011, as part of the Chevron Merger (see Note 4), Chevron acquired 8,000 cumulative Class C Preferred Units of limited partner interest (the “Class C Preferred Units”), which were previously owned by AEI. On May 27, 2011, the Partnership redeemed the Class C Preferred Units for cash at the liquidation value of $1,000 per unit, or $8.0 million, plus $0.2 million of accrued dividends. The Partnership recognized $0.4 million of preferred dividends for the year ended December 31, 2011 which are presented as reductions of net income to determine the net income attributable to common limited partners and the General Partner on its consolidated statements of operations.

Class D Preferred Units

In November 2012, the Partnership entered into a unit purchase agreement for a private placement of $200.0 million of newly-created Class D convertible preferred units (“Class D Preferred Units”) to third party investors. The unit purchase agreement was intended to provide financing for a portion of the Cardinal Acquisition. The unit purchase agreement was terminated when the Partnership raised more than $150.0 million in common unit equity. The Partnership paid each investor a commitment fee equal to 2.0% of its commitment at the time of termination for a total expense of $4.0 million, which was recorded as other costs on the Partnership's consolidated statements of operations.

On May 7, 2013, the Partnership completed a private placement of $400.0 million of its Class D Preferred Units to third party investors, at a negotiated price per unit of $29.75, resulting in net proceeds of $397.7 million pursuant to the Class D preferred unit purchase agreement dated April 16, 2013 (the "Commitment Date"). The General Partner contributed $8.2 million to maintain its 2.0% general partnership interest upon the issuance of the Class D Preferred Units. The Partnership used the proceeds to fund a portion of the purchase price of the TEAK Acquisition (see Note 3). The Class D Preferred Units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The Partnership has the right to convert the Class D Preferred Units, in whole but not in part, beginning one year following their issuance, into an equal number of common units, subject to customary anti-dilution adjustments. Unless previously converted, all Class D Preferred Units will convert into common units on May 7, 2015. In the event of any liquidation, dissolution or winding up of the Partnership or the sale or other disposition of all or substantially all of the assets of the Partnership, the holders of the Class D Preferred Units are entitled to receive, out of the assets of the Partnership available for distribution to unit holders, prior and in preference to any distribution of any assets of the Partnership to the holders of any other existing or subsequently issued units, an amount equal to $29.75 per Class D Preferred Unit plus any unpaid preferred distributions.

Upon the issuance of the Class D Preferred Units, the Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class D Preferred Units. The Partnership agreed to use its commercially reasonable efforts to have the registration statement declared effective within 180 days of the date of conversion.

The fair value of the Partnership's common units on April 16, 2013 was $36.52 per unit, resulting in an embedded beneficial conversion discount ("discount") on the Class D Preferred Units of $91.0 million. The Partnership recognized the fair value of the Class D Preferred Units with the offsetting intrinsic value of the discount within Class D preferred limited partner interests on its consolidated balance sheets as of December 31, 2013. The discount will be accreted and recognized as imputed dividends over the term of the Class D Preferred Units as a reduction to net income attributable to the common limited partners and the General Partner on the Partnership's consolidated statements of operations. For the year ended December 31, 2013, the Partnership recorded $29.5 million within preferred unit imputed dividend effect on the Partnership's consolidated statements of operations to recognize the accretion of the beneficial conversion discount. The Class D Preferred Units are presented combined with a net $61.5 million unaccreted beneficial conversion discount on the Partnership's consolidated balance sheets as of December 31, 2013.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of the Partnership's General Partner. Cash distributions will be paid to the Class D Preferred Unit holders prior to any other distributions of available cash. Distributions will be determined based upon the cash distribution declared each quarter on the Partnership's common limited partner units plus a preferred yield premium. Class D Preferred Unit distributions, whether in kind units or in cash, will be accounted for as a reduction to net income attributable to the common limited partners and the General Partner. For the year ended December 31, 2013, the Partnership recorded costs related to preferred unit distributions in kind of $23.6 million on the Partnership's consolidated statements of operations. During the year ended December 31, 2013, the Partnership distributed 378,486 Class D Preferred Units to the holders of the Class D Preferred Units. The Partnership considers preferred unit distributions paid in kind to be a non-cash financing activity.

On January 28, 2014, the Partnership declared a cash distribution of $0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. Based on this declaration, the Partnership issued 274,785 Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution in kind for the quarter ended December 31, 2013 on February 14, 2014, to the preferred unitholders of record at the close of business on February 7, 2014.

NOTE 6 – PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 13) (in thousands):

	December 31, 2013	December 31, 2012	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 2,885,303	$ 2,294,024	2 – 40
Rights of way	203,136	178,234	20 – 40
Buildings	10,291	8,224	40
Furniture and equipment	13,800	10,305	3 – 7
Other	15,805	14,761	3 – 10
	3,128,335	2,505,548	
Less – accumulated depreciation	(404,143)	(305,167)	
	$ 2,724,192	$ 2,200,381	

The Partnership recorded depreciation expense on property, plant and equipment, including capital lease arrangements (see Note 13), of $99.7 million, $66.2 million and $54.3 million for the years ended December 31, 2013, 2012 and 2011, respectively, on its consolidated statements of operations.

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds was 5.8%, 6.4% and 7.0% for the years ended December 31, 2013, 2012 and 2011, respectively. The amount of interest capitalized was $7.5 million, $8.7 million and $5.1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The Partnership owns and leases certain gas treating assets that are used to remove impurities from natural gas before it is delivered into gathering systems and transmission pipelines to ensure it meets pipeline quality specifications. These assets are included within pipelines, processing and compression facilities within property, plant and equipment on the Partnership's consolidated balance sheet. Revenues from these lease arrangements are recorded within transportation, processing and other fee revenues on the Partnership's consolidated statement of operations. Future minimum rental income related to these lease arrangements is estimated to be as follows for each of the next five calendar years: 2014 - $4.0 million; 2015 - $3.0 million; 2016 - $1.0 million; 2017 - 2018 - none.

NOTE 7 – GOODWILL AND INTANGIBLE ASSETS

The Partnership recorded goodwill on its consolidated balance sheets of $368.6 million and $319.3 million at December 31, 2013 and December 31, 2012, respectively. The change in goodwill is primarily related to an addition of $188.9 million of goodwill from the TEAK Acquisition partially offset by a $96.7 million reduction in goodwill related to an adjustment of the fair value of assets acquired and liabilities assumed from the Cardinal Acquisition and a $43.9 million reduction in goodwill related to an impairment of goodwill recorded for Gas Treating reporting unit acquired as part of the Cardinal Acquisition. The goodwill related to the Cardinal Acquisition is a result of the strategic industry position and potential future synergies. The goodwill related to the TEAK Acquisition is a result of the strategic industry position (see Note 3). The Partnership expects all goodwill recorded to be deductible for tax purposes.

Subsequent to recording the final estimated fair values of the assets acquired and liabilities assumed in the Cardinal Acquisition, the Partnership determined that a portion of goodwill recorded in connection with the acquisition was impaired. The Partnership performed a qualitative assessment for goodwill impairment on the Gas Treating reporting unit. The assessment indicated the potential for goodwill recorded on Gas Treating to be impaired due to lower forecasted cash flows as compared to original forecasts. Using a combination of discounted cash flow models and market multiples for similar businesses, the Partnership measured the amount of goodwill impairment on Gas Treating to be $43.9 million. The Partnership recorded a goodwill impairment loss of $43.9 million on its consolidated statements of operations for the year ended December 31, 2013.

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions including the Cardinal and TEAK Acquisitions. As part of the TEAK Acquisition, the Partnership recognized $450.0 million of customer relationships with an estimated useful life of 13 years. As part of the Cardinal Acquisition, the Partnership recognized $232.3 million of customer relationships with estimated useful lives of 8 to 15 years, and $0.4 million of customer contracts with an estimated useful life of 2 years. The following table reflects the components of intangible assets being amortized at December 31, 2013 and 2012 (in thousands):

	December 31, 2013	December 31, 2012	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	$ 3,419	$ 119,933	2 – 10
Customer relationships	887,653	205,313	7 – 15
	891,072	325,246	
Accumulated amortization:			
Customer contracts	(779)	(746)	
Customer relationships	(194,022)	(125,140)	
	(194,801)	(125,886)	
Net carrying amount:			
Customer contracts	2,640	119,187	
Customer relationships	693,631	80,173	
Net carrying amount	$ 696,271	$ 199,360	

The weighted-average amortization period for customer contracts and customer relationships is 9.4 years and 12.1 years, respectively. The Partnership recorded amortization expense on intangible assets of $68.9 million, $23.8 million and $23.1 million for the years ended December 31, 2013, 2012 and 2011, respectively, on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2014—$78.0 million; 2015 through 2016—$72.8 million per year; 2017—$66.7 million per year; 2018—$58.3 million.

The valuation assessment for the TEAK Acquisition has not been completed as of December 31, 2013 and the estimates of fair value of goodwill and intangible assets with finite lives reflected as of December 31, 2013 are subject to change and the change may be material (see Note 3).

NOTE 8 – OTHER ASSETS

The following is a summary of other assets (in thousands):

	December 31, 2013	December 31, 2012
Deferred finance costs, net of accumulated amortization of $22,034 and $23,536 at December 31, 2013 and 2012, respectively	$ 41,094	$ 30,496
Security deposits	5,367	2,097
	$ 46,461	$ 32,593

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). The Partnership incurred $22.8 million, $14.4 million and $4.2 million of deferred finance costs during the years ended December 31, 2013, 2012 and 2011, respectively, related to various financing activities (see Note 13). During the year ended December 31, 2013, the Partnership redeemed all of its outstanding $365.8 million 8.75% unsecured senior notes due June 15, 2018 ("8.75% Senior Notes") (see Note 13) and recognized accelerated amortization of deferred financing costs. During the years ended December 31, 2013 and 2011, the Partnership recorded $5.3 million and $5.2 million, respectively, related to accelerated amortization of deferred financing costs associated with the retirement of debt, which is included in loss on early extinguishment of debt on the Partnership's consolidated statement of operations. There was no accelerated amortization of deferred financing costs during the year ended December 31, 2012. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was $7.0 million, $4.7 million and $4.5 million for the years ended December 31, 2013, 2012 and 2011, respectively, which is recorded within interest expense on the Partnership's consolidated statements of operations.

NOTE 9 – INCOME TAXES

As part of the Cardinal Acquisition (see Note 3), the Partnership acquired APL Arkoma, Inc., a taxable subsidiary. The components of the federal and state income tax benefit of the Partnership's taxable subsidiary for the years ended December 31, 2013 and 2012 are summarized as follows (in thousands):

	Years Ended December 31,	
	2013	2012
Deferred expense (benefit) :		
Federal	$ (2,024)	$ 158
State	(236)	18
Total income tax expense (benefit)	$ (2,260)	$ 176

The components of net deferred tax liabilities as of December 31, 2013 and 2012 consist of the following (in thousands):

	December 31, 2013	December 31, 2012
Deferred tax assets:		
Net operating loss tax carryforwards and alternative minimum tax credits	$ 14,900	$ 10,277
Deferred tax liabilities:		
Excess of asset carrying value over tax basis	(48,190)	(40,535)
Net deferred tax liabilities	$ (33,290)	$ (30,258)

As of December 31, 2013, the Partnership had net operating loss carry forwards for federal income tax purposes of approximately $38.5 million, which expire at various dates from 2029 to 2033. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 10 – DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price risk management activities. The Partnership uses financial swap and put option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under its swap agreements, the Partnership receives a fixed price and remits a floating price based on certain indices for the relevant contract period. The swap agreement sets a fixed price for the product being hedged. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. A costless collar is a combination of a purchased put option and a sold call option, in which the premiums net to zero. A costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

The Partnership no longer applies hedge accounting for derivatives. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. The change in fair value of commodity-based derivative instruments, which was previously recognized in accumulated other comprehensive loss within equity on the Partnership's consolidated balance sheets, was reclassified to the Partnership's consolidated statements of operations at the time the originally hedged physical transactions affected earnings. The Partnership has reclassified all earnings out of accumulated other comprehensive income (loss), within equity on the Partnership's consolidated balance sheet and there was no balance outstanding as of the years ended December 31, 2013 and 2012.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of setoff at the time of settlement of the derivatives. Due to the right of setoff, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership's consolidated balance sheets as the initial value of the options. Changes in the fair value of the options are recognized within derivative gain (loss), net as unrealized gain (loss) on the Partnership's consolidated statements of operations. Premiums are reclassified to realized gain (loss) within derivative gain (loss), net at the time the option expires or is exercised. The Partnership reflected net derivative liabilities on its consolidated balance sheet of $9.1 million at December 31, 2013, and net derivative assets of $31.0 million at December 31, 2012.

The following tables summarize the Partnership's gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets and liabilities on the Partnership's consolidated balance sheets for the periods indicated (in thousands):

Offsetting of Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
As of December 31, 2013:			
Current portion of derivative assets	$ 1,310	$ (1,136)	$ 174
Long-term portion of derivative assets	5,082	(2,812)	2,270
Current portion of derivative liabilities	1,612	(1,612)	—
Long-term portion of derivative liabilities	949	(949)	—
Total derivative assets, net	$ 8,953	$ (6,509)	$ 2,444
As of December 31, 2012:			
Current portion of derivative assets	$ 23,534	$ (457)	$ 23,077
Long-term portion of derivative assets	9,637	(1,695)	7,942
Total derivative assets, net	$ 33,171	$ (2,152)	$ 31,019

Offsetting of Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
As of December 31, 2013:			
Current portion of derivative assets	$ (1,136)	$ 1,136	$ —
Long-term portion of derivative assets	(2,812)	2,812	—
Current portion of derivative liabilities	(12,856)	1,612	(11,244)
Long-term portion of derivative liabilities	(1,269)	949	(320)
Total derivative liabilities, net	$ (18,073)	$ 6,509	$ (11,564)
As of December 31, 2012:			
Current portion of derivative liabilities	$ (457)	$ 457	$ —
Long-term portion of derivative liabilities	(1,695)	1,695	—
Total derivative liabilities, net	$ (2,152)	$ 2,152	$ —

The following table summarizes the Partnership's commodity derivatives as of December 31, 2013, (fair value and volumes in thousands):

Production Period	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Fixed price swaps				
2014	Natural gas	12,900	$ 3.98	$ (2,588)
2015	Natural gas	16,960	4.23	1,368
2016	Natural gas	6,150	4.30	950
2014	NGLs	82,404	1.18	(9,791)
2015	NGLs	41,454	1.08	(2,083)
2016	NGLs	6,300	1.03	(92)
2014	Crude oil	312	92.37	(1,245)
2015	Crude oil	60	85.13	(186)
Total fixed price swaps				(13,667)
Purchased Put Options				
2014	Natural gas	600	4.13	168
2014	NGLs	4,410	1.00	100
2015	NGLs	1,890	0.90	110
2014	Crude oil	449	94.69	2,019
2015	Crude oil	270	89.18	2,150
Total options				4,547
Total derivatives				$ (9,120)

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.
(2) See Note 11 for discussion on fair value methodology.

The following tables summarize the gross effect of all derivative instruments on the Partnership's consolidated statements of operations for the periods indicated (in thousands):

	For the Years ended December 31, 2013	2012	2011
Derivatives previously designated as cash flow hedges			
Loss reclassified from accumulated other comprehensive loss into natural gas and liquids sales	$ —	$ (4,390)	$ (6,834)
Derivatives not designated as hedges			
Gain (loss) recognized in derivative gain (loss), net:			
Commodity contract—realized(1)	$ (324)	$10,993	$(13,123)
Commodity contract—unrealized(2)	(28,440)	20,947	(7,329)
Derivative gain (loss), net	$(28,764)	$31,940	$(20,452)

(1) Realized gain (loss) represents the gain or loss incurred when the derivative contract expires and/or is cash settled.

(2) Unrealized gain (loss) represents the mark-to-market gain or loss recognized on open derivative contracts, which have not yet settled.

NOTE 11 — FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into Levels 1, 2 and 3 (see Note 2 "Fair Value of Financial Instruments").

Derivative Instruments

At December 31, 2013, the valuations for all the Partnership's derivative contracts are defined as Level 2 assets and liabilities within the same class of nature and risk, with the exception of the Partnership's NGL fixed price swaps and NGL options, which are defined as Level 3 assets and liabilities within the same class of nature and risk.

The Partnership's Level 2 commodity derivatives include natural gas and crude oil swaps and options, which are calculated based upon observable market data related to the change in price of the underlying commodity. These swaps and options are calculated by utilizing the New York Mercantile Exchange ("NYMEX") quoted prices for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Valuations for the Partnership's NGL options are based on forward price curves developed by financial institutions, and therefore are defined as Level 3. The NGL options are over-the-counter instruments that are not actively traded in an open market, thus the Partnership utilizes the valuations provided by the financial institutions that provide the NGL options for trade. The Partnership tests these valuations for reasonableness through the use of an internal valuation model.

Valuations for the Partnership's NGL fixed price swaps are based on forward price curves provided by a third party, which the Partnership considers to be Level 3 inputs. The prices are adjusted based upon the relationship between the prices for the product/locations quoted by the third party and the underlying product/locations utilized for the swap contracts, as determined by a regression model of the historical settlement prices for the different product/locations. The regression model is recalculated on a quarterly basis. This adjustment is an unobservable Level 3 input. The NGL fixed price swaps are over-the-counter instruments which are not actively traded in an open market. However, the prices for the underlying products and locations do have a direct correlation to the prices for the products and locations provided by the third party, which are based upon trading activity for the products and locations quoted. A change in the relationship between these prices would have a direct impact upon the unobservable adjustment utilized to calculate the fair value of the NGL fixed price swaps.

The following table represents the Partnership's derivative assets and liabilities recorded at fair value as of December 31, 2013 and 2012 (in thousands):

	Level 1	Level 2	Level 3	Total
December 31, 2013				
Assets				
Commodity swaps	$ —	$ 2,994	$ 1,412	$ 4,406
Commodity options	—	4,337	210	4,547
Total assets	—	7,331	1,622	8,953
Liabilities				
Commodity swaps	—	(4,695)	(13,378)	(18,073)
Total liabilities	—	(4,695)	(13,378)	(18,073)
Total derivatives	$ —	$ 2,636	$(11,756)	$ (9,120)
December 31, 2012				
Assets				
Commodity swaps	$ —	$ 2,007	$ 17,573	$ 19,580
Commodity options	—	7,322	6,269	13,591
Total assets	—	9,329	23,842	33,171
Liabilities				
Commodity swaps	—	(1,393)	(759)	(2,152)
Total liabilities	—	(1,393)	(759)	(2,152)
Total derivatives	$ —	$ 7,936	$ 23,083	$ 31,019

The Partnership's Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership's Level 3 derivative instruments for the years ended December 31, 2013 and 2012 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance – January 1, 2012	49,644	$ (1,733)	92,610	$ 18,279	$ 16,546
New contracts(1)	84,294	—	—	—	—
Cash settlements from unrealized gain (loss)(2)(3)	(46,872)	(7,863)	(54,054)	(142)	(8,005)
Net change in unrealized gain (loss)(2)	—	26,410	—	923	27,333
Deferred option premium recognition(3)	—	—	—	(12,791)	(12,791)
Balance – December 31, 2012	87,066	$ 16,814	38,556	$ 6,269	$ 23,083
New contracts(1)	104,328	—	7,560	816	816
Cash settlements from unrealized gain (loss)(2)(3)	(61,236)	(11,496)	(39,816)	8,545	(2,951)
Net change in unrealized gain (loss)(2)	—	(17,284)	—	(2,367)	(19,651)
Deferred option premium recognition(3)	—	—	—	(13,053)	(13,053)
Balance – December 31, 2013	130,158	$(11,966)	6,300	$ 210	$(11,756)

(1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.
(2) Included within derivative gain (loss), net on the Partnership's consolidated statements of operations.
(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

The following table provides a summary of the unobservable inputs used in the fair value measurement of the Partnership's NGL fixed price swaps at December 31, 2013 and 2012 (in thousands):

	Gallons	Third Party Quotes(1)	Adjustments(2)	Total Amount
As of December 31, 2013				
Propane swaps	100,296	$ (10,260)	$ —	$(10,260)
Isobutane swaps	6,300	(2,342)	955	(1,387)
Normal butane swaps	7,560	40	322	362
Natural gasoline swaps	16,002	132	(813)	(681)
Total NGL swaps – December 31, 2013	130,158	$ (12,430)	$ 464	$(11,966)
As of December 31, 2012				
Propane swaps	69,678	$ 16,302	$ (552)	$ 15,750
Isobutane swaps	1,134	(219)	187	(32)
Normal butane swaps	6,174	(909)	242	(667)
Natural gasoline swaps	10,080	3,247	(1,484)	1,763
Total NGL swaps – December 31, 2012	87,066	$ 18,421	$ (1,607)	$ 16,814

(1) Based upon the difference between the quoted market price provided by the third party and the fixed price of the swap.
(2) Product and location basis differentials calculated through the use of a regression model, which compares the difference between the settlement prices for the products and locations quoted by the third party and the settlement prices for the actual products and locations underlying the derivatives, using a three year historical period.

The following table provides a summary of the regression coefficient utilized in the calculation of the unobservable inputs for the Level 3 fair value measurements for the NGL fixed price swaps for the periods indicated (in thousands):

	Level 3 NGL Swap Fair Value Adjustments	Adjustment based upon Regression Coefficient		
		Lower 95%	Upper 95%	Average
As of December 31, 2013:				
Isobutane	955	1.1184	1.1284	1.1234
Normal butane	322	1.0341	1.0386	1.0364
Natural gasoline	(813)	0.9727	0.9751	0.9739
Total Level 3 adjustments – December 31, 2013	$ 464			
As of December 31, 2012:				
Propane	$ (552)	0.9019	0.9122	0.9071
Isobutane	187	1.1285	1.1376	1.1331
Normal butane	242	1.0370	1.0416	1.0393
Natural gasoline	(1,484)	0.8988	0.9169	0.9078
Total Level 3 adjustments – December 31, 2012	$ (1,607)			

NGL Linefill

The Partnership had $14.5 million and $7.8 million of NGL linefill at December 31, 2013 and 2012, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties, for which the counterparty will pay at a designated later period at a price determined by the then market price. The Partnership's NGL linefill held by one counterparty will be settled at various periods in the future and is defined as a Level 3 asset, which is valued using the same forward price curve utilized to value the Partnership's NGL fixed price swaps. The product/location adjustment based upon the multiple regression analysis, which was included in the value of the linefill, was a reduction of $0.4 million and $0.4 million as of December 31, 2013 and 2012, respectively. The Partnership's NGL linefill held by other counterparties is adjusted on a monthly basis according to the volumes delivered to the counterparties each period and is valued on a first in first out ("FIFO") basis.

The following table provides a summary of changes in fair value of the Partnership's NGL linefill for the years ended December 31, 2013 and 2012 (in thousands):

	Linefill Valued at Market		Linefill Valued on FIFO		Total NGL Linefill	
	Gallons	Amount	Gallons	Amount	Gallons	Amount
Balance – December 31, 2011	10,408	$11,529	—	$ —	10,408	$ 11,529
Cash Settlements(1)	(2,520)	(2,698)	—	—	(2,520)	(2,698)
Net change in NGL linefill valuation(1)	—	(2,111)	—	—	—	(2,111)
Acquired NGL linefill(2)	1,260	1,063	—	—	1,260	1,063
Balance – December 31, 2012	9,148	$ 7,783	—	$ —	9,148	$ 7,783
Deliveries into NGL linefill	—	—	80,758	60,565	80,758	60,565
NGL linefill sales	(3,360)	(2,795)	(71,433)	(52,155)	(74,793)	(54,950)
Net change in NGL linefill valuation(1)	—	(249)	—	—	—	(249)
Acquired NGL linefill(2)	—	—	2,213	1,368	2,213	1,368
Balance – December 31, 2013	5,788	$ 4,739	11,538	$ 9,778	17,326	$ 14,517

(1) Included within natural gas and liquid sales on the Partnership's consolidated statements of operations.
(2) NGL linefill acquired as part of the Cardinal and TEAK Acquisitions (see Note 3).

Contingent Consideration

In February 2012, the Partnership acquired a gas gathering system and related assets for an initial net purchase price of $19.0 million. The Partnership agreed to pay up to an additional $12.0 million, payable in two equal amounts, if certain volumes are achieved on the acquired gathering system within a specified time period ("Trigger Payments"). Sufficient volumes were achieved in December 2012 and the Partnership paid the first Trigger Payment of $6.0 million in January 2013. As of December 31, 2013, the fair value of the remaining Trigger Payment resulted in a $6.0 million long term liability, which was recorded within other long term liabilities on the Partnership's consolidated balance sheets. The range of the undiscounted amount the Partnership could pay related to the remaining Trigger Payment is between $0.0 and $6.0 million.

Other Financial Instruments

The estimated fair value of the Partnership's other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership's current assets and liabilities on its consolidated balance sheets, other than the derivatives, NGL linefill and contingent consideration discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1 values. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value and thus is categorized as a Level 1 value. The estimated fair value of the Partnership's Senior Notes (see Note 13) is based upon the market approach and calculated using the yield of the Senior Notes as provided by financial institutions and thus is categorized as a Level 3 value. The estimated fair values of the Partnership's total debt at December 31, 2013 and 2012, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were $1,663.6 million and $1,216.4 million, respectively, compared with the carrying amounts of $1,707.3 million and $1,179.9 million, respectively.

Acquisitions

On December 20, 2012, the Partnership completed the Cardinal Acquisition (see Note 3). On May 7, 2013, the Partnership completed the TEAK Acquisition (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. These inputs require significant judgments and estimates at the time of the valuation. The estimates of fair value of the TEAK assets as of the acquisition date, which are reflected in the Partnership's consolidated balance sheet as of December 31, 2013, are subject to change as the final valuation has not yet been completed, and such changes may be material (see Note 3).

NOTE 12 — ACCRUED LIABILITIES

The following is a summary of accrued liabilities (in thousands):

	December 31, 2013	December 31, 2012
Accrued capital expenditures	$ 17,898	$ 8,336
Acquisition-related liabilities	8,933	—
Cardinal Acquisition payable (offset by funds in escrow)	—	25,000
Acquisition-based short-term contingent consideration	—	6,000
Accrued ad valorem and production taxes	3,551	3,950
Other	17,067	14,466
	$ 47,449	$ 57,752

NOTE 13 — DEBT

Total debt consists of the following (in thousands):

	December 31, 2013	December 31, 2012
Revolving credit facility	$ 152,000	$ 293,000
8.750% Senior notes – due 2018	—	370,184
6.625% Senior notes – due 2020	504,556	505,231
5.875% Senior notes – due 2023	650,000	—
4.750% Senior notes – due 2021	400,000	—
Capital lease obligations	754	11,503
Total debt	1,707,310	1,179,918
Less current maturities	(524)	(10,835)
Total long term debt	$ 1,706,786	$ 1,169,083

The aggregate amount of the Partnership's debt maturities is as follows (in thousands):

Years Ended December 31:	
2014	$ 524
2015	225
2016	5
2017	152,000
2018	—
Thereafter	1,550,000
Total principal maturities	1,702,754
Unamortized premium	4,556
Total debt	$1,707,310

Cash payments for interest related to debt, net of capitalized interest, were $66.3 million, $28.3 million and $27.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Revolving Credit Facility

At December 31, 2013, the Partnership had a $600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. Borrowings under the revolving credit facility bear interest, at the Partnership's option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% and (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at December 31, 2013, was 4.0%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $0.1 million was outstanding at December 31, 2013. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At December 31, 2013, the Partnership had $447.9 million of remaining committed capacity under its revolving credit facility.

Borrowings under the revolving credit facility are secured by (i) a lien on and security interest in all the Partnership's property and that of its subsidiaries, except for the assets owned by Atlas Pipeline Mid-Continent WestOk, LLC ("WestOK LLC") and Atlas Pipeline Mid-Continent WestTex, LLC ("WestTX LLC"), entities in which the Partnership has 95% interests, and Centrahoma, in which the Partnership has a 60% interest; and their respective subsidiaries; and (ii) by the guaranty of each of the Partnership's consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including requirements that the Partnership maintain certain financial thresholds and restrictions on the Partnership's ability to (1) incur additional indebtedness, (2) make certain acquisitions, loans or investments, (3) make distribution payments to its unitholders if an event of default exists, or (4) enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is unable to borrow under its revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute "working capital borrowings" pursuant to its partnership agreement.

The events that constitute an event of default for the revolving credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership's General Partner.

On April 19, 2013, the Partnership entered into an amendment to the credit agreement which, among other changes:

- allowed the TEAK Acquisition to be a Permitted Investment, as defined in the credit agreement;
- did not require the joint venture interests acquired in the TEAK Acquisition to be guarantors;
- permitted the payment of cash distributions, if any, on the Class D Preferred Units so long as the Partnership has a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to $50 million; and
- modified the definition of Consolidated Funded Debt Ratio, Interest Coverage Ratio and Consolidated EBITDA to allow for an Acquisition Period whereby the terms for calculating each of these ratios have been adjusted.

As of December 31, 2013, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At December 31, 2013, the Partnership had $500.0 million principal outstanding of 6.625% Senior Notes, $650.0 million principal outstanding of 5.875% unsecured senior notes due August 1, 2023 (“5.875% Senior Notes”), and $400.0 million of 4.75% Senior Notes (with the 6.625% Senior Notes and 5.875% Senior Notes, the “Senior Notes”).

The Senior Notes are subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership’s secured debt, including the Partnership’s obligations under its revolving credit facility.

Indentures governing the Senior Notes contain covenants, including limitations of the Partnership’s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all its assets. The Partnership is in compliance with these covenants as of December 31, 2013.

6.625% Senior Notes

The 6.625% Senior Notes are presented combined with a net $4.6 million unamortized premium as of December 31, 2013. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable at any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

On September 28, 2012, the Partnership issued $325.0 million of the 6.625% Senior Notes in a private placement transaction, at par. The Partnership received net proceeds of $318.9 million after underwriting commissions and other transaction costs and utilized the proceeds to reduce the outstanding balance on its revolving credit facility.

On December 20, 2012, the Partnership issued $175.0 million of the 6.625% Senior Notes in a private placement transaction. The 6.625% Senior Notes were issued at a premium of 103.0% of the principal amount for a yield of 6.0%. The Partnership received net proceeds of $176.1 million after underwriting commissions and other transaction costs and utilized the proceeds to partially finance the Cardinal Acquisition (see Note 3). Of the $176.1 million net proceeds, $176.5 million was received during the year ended December 31, 2012, while additional expenses of $0.4 million were incurred during the year ended December 31, 2013.

The Partnership commenced an exchange offering for the 6.625% Senior Notes on September 18, 2013 and the exchange offer was completed on October 16, 2013. Pursuant to the terms of the registration rights agreement related to the 6.625% Senior Notes, because the exchange offer was not consummated within the aforementioned timeframe, the Partnership incurred a 0.25% interest penalty of $52 thousand for the period from September 23, 2013 through consummation of the exchange offer on October 16, 2013.

8.125% Senior Notes

On April 8, 2011, the Partnership redeemed all the 8.125% senior unsecured notes due on December 15, 2015 (“8.125% Senior Notes”). The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. The Partnership paid $293.7 million to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest. For the year ended December 31, 2011, the Partnership recorded a loss of $19.4 million within loss on early extinguishment of debt on the Partnership’s consolidated statements of operations, related to the redemption of the 8.125% Senior Notes. The loss includes the $11.2 million premium paid; a $3.1 million write off of unamortized discount; and a $5.1 million write off of deferred financing costs.

8.75% Senior Notes

On April 7, 2011, the Partnership redeemed $7.2 million of the 8.75% unsecured senior notes due June 15, 2018 (“8.75% Senior Notes”), which were tendered upon its offer to purchase the 8.75% Senior Notes, at par. The Laurel Mountain Sale (see Note 4) constituted an “Asset Sale” pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, the Partnership offered to purchase any and all of the 8.75% Senior Notes. For the year ended December 31, 2011, the Partnership recorded a loss of $0.2 million within loss on early extinguishment of debt on the Partnership’s consolidated statements of operations, related to the write off of deferred financing costs for the 8.75% Senior Notes.

On November 21, 2011, the Partnership issued $150.0 million of the 8.75% Senior Notes in a private placement transaction. The 8.75% Senior Notes were issued at a premium of 103.5% of the principal amount for a yield of 7.82%. The Partnership received net proceeds of $152.4 million after underwriting commissions and other transaction costs and utilized the proceeds to reduce the outstanding balance on its revolving credit facility.

On January 28, 2013, the Partnership commenced a cash tender offer for any and all of its outstanding $365.8 million 8.75% Senior Notes, excluding unamortized premium, and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default contained in the indenture governing the 8.75% Senior Notes (“8.75% Senior Notes Indenture”). Approximately $268.4 million aggregate principal amount of the 8.75% Senior Notes were validly tendered as of the expiration date of the consent solicitation. In February 2013, the Partnership accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and paid $291.4 million to redeem the $268.4 million principal plus $11.2 million make-whole premium, $3.7 million accrued interest and $8.0 million consent payment. The Partnership entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture.

On March 12, 2013, the Partnership paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes plus a $6.3 million make-whole premium and $2.0 million in accrued interest. The Partnership funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes. During the year ended December 31, 2013, the Partnership recorded a loss of $26.6 million within loss on early extinguishment of debt on the Partnership's consolidated statements of operations, related to the redemption of the 8.75% Senior Notes. The loss includes $17.5 million premiums paid; $8.0 million consent payment; $5.3 million write off of deferred financing costs, offset by $4.2 million recognition of unamortized premium.

5.875% Senior Notes

On February 11, 2013, the Partnership issued $650.0 million of the 5.875% Senior Notes in a private placement transaction. The 5.875% Senior Notes were issued at par. The Partnership received net proceeds of $637.3 million after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the revolving credit agreement. Interest on the 5.875% Senior Notes is payable semi-annually in arrears on February 1 and August 1. The 5.875% Senior Notes are redeemable any time after February 1, 2018, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Partnership commenced an exchange offer for the 5.875% Senior Notes on December 10, 2013 and the exchange offer was completed on January 9, 2014.

4.75% Senior Notes

On May 10, 2013, the Partnership issued $400.0 million of the 4.75% Senior Notes in a private placement transaction. The 4.75% Senior Notes were issued at par. The Partnership received net proceeds of $391.2 million after underwriting commissions and other transactions costs and utilized the proceeds to repay a portion of the outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition (see Note 3). Interest on the 4.75% Senior Notes is payable semi-annually in arrears on May 15 and November 15. The 4.75% Senior Notes are due on November 15, 2021 and are redeemable any time after March 15, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Partnership commenced an exchange offer for the 4.75% Senior Notes on December 10, 2013 and the exchange offer was completed on January 9, 2014.

Capital Leases

During the year ended December 31, 2013, the Partnership accelerated payment on certain leases and purchased the leased property by paying approximately $7.5 million in accordance with the lease agreements. These leases were to mature in August 2013.

During the year ended December 31, 2012, the Partnership recorded $1.9 million related to new capital lease agreements within property, plant and equipment and recorded an offsetting liability within long-term debt on the Partnership's consolidated balance sheets. This amount was based upon the minimum payments required under the leases and the Partnership's incremental borrowing rate. As part of the Cardinal Acquisition (see Note 3), the Partnership acquired an additional $0.9 million of capital leases during the year ended December 31, 2012.

The following is a summary of the leased property under capital leases as of December 31, 2013 and 2012, which are included within property, plant and equipment (see Note 6) (in thousands):

	December 31, 2013	December 31, 2012
Pipelines, processing and compression facilities	$ 2,281	$ 15,457
Less – accumulated depreciation	(330)	(1,066)
	$ 1,951	$ 14,391

Depreciation expense for leased properties was $340 thousand, $723 thousand and $152 thousand for the years ended December 31, 2013, 2012 and 2011, respectively, which is included within depreciation and amortization expense on the Partnership's consolidated statements of operations (see Note 6).

As of December 31, 2013, future minimum lease payments related to the capital leases are as follows (in thousands):

	Capital Lease Minimum Payments
2014	$ 524
2015	225
2016	5
2017	—
2018	—
Thereafter	—
Total minimum lease payments	754
Less amounts representing interest	(26)
Present value of minimum lease payments	728
Less current portion of capital lease obligations	(503)
Long-term capital lease obligations	$ 225

NOTE 14 — COMMITMENTS AND CONTINGENCIES

The Partnership has noncancelable operating leases for equipment and office space that expire at various dates. Certain operating leases provide the Partnership with the option to renew for additional periods. Where operating leases contain escalation clauses, rent abatements, and/or concessions, the Partnership applies them in the determination of straight-line rent expense over the lease term. Leasehold improvements are amortized over the shorter of the lease term or asset life, which may include renewal periods where the renewal is reasonably assured, and is included in the determination of straight-line rent expense. Total rental expense for the years ended December 31, 2013, 2012 and 2011 was $11.3 million, $5.5 million and $5.5 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2013 is as follows (in thousands):

Years Ended December 31:	
2014	$ 4,629
2015	4,042
2016	3,638
2017	842
2018	745
Thereafter	965
	$14,861

The Partnership has certain long-term unconditional purchase obligations and commitments, consisting primarily of transportation contracts. These agreements provide for transportation services to be used in the ordinary course of the Partnership's operations. Transportation fees paid related to these contracts, including minimum shipment payments, were $34.8 million, $10.5 million and $10.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. The future fixed and determinable portion of the obligations as of December 31, 2013 was as follows: 2014—$9.5 million; 2015 to 2017—$3.5 million per year; and 2018—$2.7 million.

The Partnership had committed approximately $102.5 million for the purchase of property, plant and equipment at December 31, 2013.

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on its financial condition or results of operations.

NOTE 15 — CONCENTRATIONS OF CREDIT RISK

The Partnership sells natural gas, NGLs and condensate under contract to various purchasers in the normal course of business, within the Gathering and Processing segment (see Note 18). For the year ended December 31, 2013, the Partnership had three customers that individually accounted for approximately 29%, 17% and 14%, respectively, of the Partnership's consolidated total third party revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2012, the Partnership had two customers that individually accounted for approximately 48% and 15%, respectively, of the Partnership's consolidated total third party revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2011, the Partnership had two customers that individually accounted for approximately 60% and 16%, respectively, of the Partnership's consolidated total third party revenues, excluding the impact of all financial derivative activity. Additionally, the Partnership had three customers that individually accounted for approximately 23%, 20%, and 10%, respectively, of the Partnership's consolidated accounts receivable at December 31, 2013, and two customers that individually accounted for approximately 45% and 14%, respectively, of the Partnership's consolidated accounts receivable at December 31, 2012.

The Partnership has certain producers that supply a majority of the natural gas to its gathering systems and processing facilities. A reduction in the volume of natural gas that any one of these producers supply to the Partnership could adversely affect its operating results unless comparable volume could be obtained from other producers in the surrounding region.

The Partnership places its temporary cash investments in high quality short-term money market instruments and deposits with high quality financial institutions. At December 31, 2013, the Partnership and its subsidiaries had $5.7 million in deposits at banks, of which $5.3 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

NOTE 16 — BENEFIT PLANS

Share-based payments to employees, which are not cash settled, including grants of unit options and phantom units, are recognized within equity in the financial statements based on their fair values on the date of the grant. Share-based payments to non-employees that have a cash settlement option are recognized within liabilities in the financial statements based upon their current fair market value.

A phantom unit entitles a grantee to receive a common limited partner unit upon vesting of the phantom unit. In tandem with phantom unit grants, participants may be granted a distribution equivalent right ("DER"), which is the right to receive cash per phantom unit in an amount equal to and at the same time as the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. The compensation committee appointed by the General Partner's managing board (the "Compensation Committee") determines the vesting period for phantom units.

A unit option entitles a grantee to purchase a common limited partner unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option is equal to the fair market value of the common unit on the date of grant of the option. The Compensation Committee determines how the exercise price may be paid by the grantee as well as the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant.

Long-Term Incentive Plans

The Partnership has a 2004 Long-Term Incentive Plan ("2004 LTIP") and a 2010 Long-Term Incentive Plan ("2010 LTIP" and collectively with the 2004 LTIP, the "LTIPs") in which officers, employees, non-employee managing board members of the General Partner, employees of the General Partner's affiliates and consultants are eligible to participate. The LTIPs are administered by the Compensation Committee. Under the LTIPs, the Compensation Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At December 31, 2013, the Partnership had 1,446,553 phantom units outstanding under the Partnership's LTIPs, with 840,870 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options that have vested and have been exercised.

Partnership Phantom Units

Through December 31, 2013, phantom units granted to employees under the LTIPs generally had vesting periods of four years. In conjunction with the approval of the 2010 LTIP, the holders of 300,000 equity indexed bonus units ("Bonus Units"), under the Partnership's subsidiary's plan discussed below, agreed to exchange their Bonus Units for an equivalent number of phantom units. These phantom units vested over a three year period. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards to non-employee members of the board automatically vest upon a change of control, as defined in the LTIPs. At December 31, 2013, there were 464,452 units outstanding under the LTIPs that will vest within the following twelve months.

The Partnership is authorized to purchase common units from employees to cover employee-related taxes when certain phantom units have vested. During the years ended December 31, 2012 and 2011, the Partnership purchased and retired 24,052 common units and 28,878 common units, respectively, to cover employee-related taxes, for a cost of $0.7 million and $1.0 million, respectively. The purchased and retired units were recorded as a reduction of equity on the Partnership's consolidated balance sheet. There were no phantom units purchased and retired during the year ended December 31, 2013.

On February 17, 2011, the employment agreement with the Chief Executive Officer ("CEO") of the General Partner was terminated in connection with the Chevron Merger (see Note 4) and 75,250 outstanding phantom units, which represents all outstanding phantom units held by the CEO, automatically vested and were issued.

All phantom units outstanding under the LTIPs at December 31, 2013 include DERs granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were $3.1 million, $2.0 million and $0.8 million during the years ended December 31, 2013, 2012 and 2011, respectively. These amounts were recorded as reductions of equity on the Partnership's consolidated balance sheets.

The following table sets forth the Partnership's LTIPs phantom unit activity for the periods indicated:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	1,053,242	$ 33.21	394,489	$ 21.63	490,886	$ 11.75
Granted	744,997	38.96	907,637	34.94	178,318	33.47
Forfeited	(61,550)	36.11	(67,675)	29.83	(41,250)	13.49
Matured and issued(2)(3)	(290,136)	31.88	(181,209)	17.88	(233,465)	11.34
Outstanding, end of period(4)(5)	1,446,553	$ 36.32	1,053,242	$ 33.21	394,489	$ 21.63
Non-cash compensation expense recognized (in thousands)(6)		$ 19,344		$11,635		$ 3,271

(1) Fair value based upon weighted average grant date price.
(2) The intrinsic values for phantom unit awards exercised during the years ended December 31, 2013, 2012 and 2011 were $10.7 million, $5.5 million and $7.4 million, respectively.
(3) There were 1,677 phantom units; 792 phantom units; and 414 phantom units, which were settled for $58 thousand, $26 thousand and $14 thousand cash during the years ended December 31, 2013, 2012 and 2011, respectively.
(4) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2013 and 2012 was $50.7 million and $33.3 million, respectively.
(5) There were 22,539 and 17,926 outstanding phantom unit awards at December 31, 2013 and 2012, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.
(6) Non-cash compensation expense includes incremental compensation expense of $472 thousand, related to the accelerated vesting of phantom units held by the CEO of the General Partner during the year ended December 31, 2011.

At December 31, 2013, the Partnership had approximately $30.8 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.1 years.

Partnership Unit Options

At December 31, 2013, there were no unit options outstanding. On February 17, 2011, the employment agreement with the CEO of the General Partner was terminated in connection with the Chevron Merger (see Note 4) and 50,000 outstanding unit options held by the CEO automatically vested. As of December 31, 2013, all unit options had been exercised.

The following table sets forth the LTIP unit option activity for the periods indicated:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	—	$ —	—	$ —	75,000	$ 6.24
Granted	—	—	—	—	—	—
Exercised(1)	—	—	—	—	(75,000)	6.24
Outstanding, end of period	—	—	—	—	—	—
Weighted average fair value of unit options per unit granted during the period	—	$ —	—	$ —	—	$ —
Non-cash compensation expense recognized (in thousands)(2)		$ —		$ —		$ 3

(1) The intrinsic value for option unit awards exercised during the year ended December 31, 2011 was $1.7 million. Approximately $0.5 million was received from exercise of unit option awards during the year ended December 31, 2011.

(2) Non-cash compensation expense includes incremental compensation expense of $2 thousand, related to the accelerated vesting of options held by the CEO of the General Partner, during the year ended December 31, 2011.

Employee Incentive Compensation Plan and Agreement

Atlas Pipeline Mid-Continent LLC, a wholly-owned subsidiary of the Partnership, has an incentive plan (the “APLMC Plan”), which allowed for equity-indexed cash incentive awards to employees of the Partnership (the “Participants”). The APLMC Plan was administered by a committee appointed by the CEO of the General Partner. Under the APLMC Plan, cash bonus units (“Bonus Unit”) were awarded to Participants at the discretion of the committee. A Bonus Unit entitled the employee to receive the cash equivalent of the then fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vested ratably over a three year period from the date of grant and automatically vested upon a change of control, death, or termination without cause, each as defined in the governing document. During the years ended December 31, 2012 and 2011, 25,500 and 24,750 Bonus Units, respectively, vested and cash payments were made for $0.7 million and $0.9 million, respectively. All outstanding bonus units became fully vested at the end of December 31, 2012. The Partnership recognized income of $79 thousand during the year ended December 31, 2012 and expense of $862 thousand during the year ended December 31, 2011, which was recorded within general and administrative expense on its consolidated statements of operations. No expense was recognized during the year ended December 31, 2013. At December 31, 2013 and 2012, Atlas Pipeline Mid-Continent LLC had no outstanding Bonus Units under the APLMC Plan and does not anticipate any further grants thereunder.

NOTE 17 – RELATED PARTY TRANSACTIONS

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of ATLS. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to its employees who perform services for the Partnership based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by ATLS based on the number of its employees who devote their time to activities on the Partnership's behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $5.0 million, $3.8 million and $1.8 million for the years ended December 31, 2013, 2012 and 2011, respectively, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the years ended December 31, 2013, 2012 and 2011. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

The Partnership compresses and gathers gas for Atlas Resource Partners, L.P. (NYSE: ARP) ("ARP") on its gathering systems located in Tennessee. ARP's general partner is wholly-owned by ATLS, and two members of the General Partner's managing board are members of ARP's board of directors. The Partnership entered into an agreement to provide these services, which extends for the life of ARP's leases, in February 2008. The Partnership charged ARP approximately $0.3 million, $0.4 million and $0.3 million in compression and gathering fees for the years ended December 31, 2013, 2012 and 2011, respectively.

The Partnership agreed to provide design, procurement and construction management services for ARP with respect to a pipeline located in Lycoming County, Pennsylvania (the "Lycoming Pipeline"). The Partnership has been reimbursed approximately $1.8 million by ARP for these services during the year ended December 31, 2013.

On February 17, 2011, the Partnership completed the Laurel Mountain Sale to Atlas Energy Resources for $409.5 million, including closing adjustments and net of expenses (See Note 4).

In connection with the TEAK Acquisition, the Partnership sold approximately 3.4 million of its Class D Preferred Units for approximately $100.0 million (See Note 5) to Omega Capital and its affiliates, which beneficially owned more than 5% of the Partnership's outstanding limited partnership units as of December 31, 2013. The sale of the Class D Preferred Units was made to Omega Capital and its affiliates upon substantially the same terms as unrelated third parties that also purchased Class D Preferred Units in connection with the TEAK Acquisition and was approved in advance by the Partnership's Conflicts Committee.

NOTE 18 – SEGMENT INFORMATION

The Partnership has two reportable segments: Gathering and Processing; and Transportation, Treating and Other ("Transportation and Treating"). These reportable segments reflect the way the Partnership manages its operations.

The Gathering and Processing segment consists of (1) the SouthOK, SouthTX, WestOK and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma and Permian Basins and the Eagle Ford Shale play in south Texas; and (2) the natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas.

The Transportation and Treating segment consists of (1) the Gas Treating operations, which own contract gas treating facilities located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford; (2) the Partnership's 20% interest in the equity income generated by WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation; and (3) through the year ended December 31, 2011, the revenues and gain on sale related to the Partnership's former 49% interest in Laurel Mountain (see Note 4). Gas Treating revenues are primarily derived from monthly lease fees for use of the treating facilities. Pipeline revenues are primarily derived from transportation fees.

In connection with the TEAK Acquisition (see Note 3), the Partnership reviewed the acquired assets to determine the proper alignment of these assets within the existing reportable segments. The gas gathering and processing facilities acquired, along with their related assets, are included in the Gathering and Processing segment since the operating activities of the acquired assets are similar to the operating activities of other assets within that segment.

The following summarizes the Partnership's reportable segment data for the periods indicated (in thousands):

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Year Ended December 31, 2013:				
Revenue:				
Revenues – third party(1)	$2,129,414	$ 5,659	$ (28,527)	$2,106,546
Revenues – affiliates	303	—	—	303
Total revenues	2,129,717	5,659	(28,527)	2,106,849
Costs and Expenses:				
Operating costs and expenses	1,783,551	1,358	—	1,784,909
General and administrative(1)	—	—	60,856	60,856
Other costs(2)	—	—	20,005	20,005
Depreciation and amortization	164,628	3,015	974	168,617
Interest expense(1)	—	—	89,637	89,637
Total costs and expenses	1,948,179	4,373	171,472	2,124,024
Equity income (loss) in joint ventures	(9,724)	4,988	—	(4,736)
Goodwill impairment loss	—	(43,866)	—	(43,866)
Loss on asset disposition	(1,519)	—	—	(1,519)
Loss on early extinguishment of debt	—	—	(26,601)	(26,601)
Income (loss) from continuing operations before tax	170,295	(37,592)	(226,600)	(93,897)
Income tax benefit	(2,260)	—	—	(2,260)
Net income (loss)	$ 172,555	$ (37,592)	$(226,600)	$ (91,637)

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

(2) For the year ended December 31, 2013, acquisition costs related to the TEAK Acquisition are carried at the corporate level.

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Year Ended December 31, 2012:				
Revenue:				
Revenues – third party(1)	$1,217,820	$ 182	$ 27,583	$1,245,585
Revenues – affiliates	435	—	—	435
Total revenues	1,218,255	182	27,583	1,246,020
Costs and Expenses:				
Operating costs and expenses	989,864	180	—	990,044
General and administrative(1)	—	—	47,206	47,206
Other costs(2)	(303)	—	15,372	15,069
Depreciation and amortization	90,029	—	—	90,029
Interest expense(1)	—	—	41,760	41,760
Total costs and expenses	1,079,590	180	104,338	1,184,108
Equity income in joint ventures	—	6,323	—	6,323
Income (loss) from continuing operations before tax	138,665	6,325	(76,755)	68,235
Income tax expense	176	—	—	176
Net income (loss)	$ 138,489	$ 6,325	$ (76,755)	$ 68,059

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

(2) For the year ended December 31, 2012, acquisition costs related to the Cardinal Acquisition are carried at the corporate level.

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Year Ended December 31, 2011:				
Revenue:				
Revenues – third party(1)	$1,329,686	$ —	$ (27,287)	$1,302,399
Revenues – affiliates	335	—	—	335
Total revenues	1,330,021	—	(27,287)	1,302,734
Costs and Expenses:				
Operating costs and expenses	1,102,330	214	—	1,102,544
General and administrative(1)	—	—	36,357	36,357
Other costs	330	710	—	1,040
Depreciation and amortization	77,435	—	—	77,435
Interest expense(1)	—	—	31,603	31,603
Total costs and expenses	1,180,095	924	67,960	1,248,979
Equity income in joint ventures	462	4,563	—	5,025
Gain on asset disposition	256,272	—	—	256,272
Loss on early extinguishment of debt	—	—	(19,574)	(19,574)
Income (loss) from continuing operations	406,660	3,639	(114,821)	295,478
Loss from discontinued operations	—	—	(81)	(81)
Net income (loss)	$ 406,660	$ 3,639	$(114,902)	$ 295,397

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

	Years Ended December 31,		
Capital Expenditures:	2013	2012	2011
Gathering and processing	$446,820	$373,533	$245,426
Transportation and treating	99	—	—
Corporate and other	3,641	—	—
	$450,560	$373,533	$245,426

Balance Sheet	December 31, 2013	December 31, 2012
Equity method investment in joint ventures:		
Gathering and processing	$ 162,511	$ —
Transportation and treating	85,790	86,002
	$ 248,301	$ 86,002
Goodwill:		
Gathering and processing	$ 368,572	$ 292,448
Transportation and treating	—	26,837
	$ 368,572	$ 319,285
Total assets:		
Gathering and processing	$ 4,146,314	$ 2,831,639
Transportation and treating	132,152	141,356
Corporate and other	49,379	92,643
	$ 4,327,845	$ 3,065,638

The following table summarizes the Partnership's natural gas and liquids sales by product or service for the periods indicated (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Natural gas and liquids sales:			
Natural gas	$ 708,817	$ 396,867	$ 400,991
NGLs	1,132,481	657,271	795,122
Condensate	118,095	85,234	72,037
Other	(249)	(2,111)	45
Total	$1,959,144	$1,137,261	$1,268,195

NOTE 19 – SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership's Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership's consolidated financial statements include the financial statements of WestOK LLC, WestTX LLC and Centrahoma as well as the Partnership's equity interests in WTLPG and the T2 Joint Ventures. Under the terms of the Senior Notes and the revolving credit facility, WestOK LLC, WestTX LLC, Centrahoma, WTLPG, and the T2 Joint Ventures are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership's stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership's consolidated accounts as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011. For the purpose of the following financial information, the Partnership's investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented in accordance with the equity method of accounting (in thousands):

Balance Sheets December 31, 2013	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$ —	$ 168	$ 4,746	$ —	$ 4,914
Accounts receivable – affiliates	765,236	—	—	(765,236)	—
Other current assets	215	52,910	185,975	(2,236)	236,864
Total current assets	765,451	53,078	190,721	(767,472)	241,778
Property, plant and equipment, net	—	723,302	2,000,890	—	2,724,192
Intangible assets, net	—	603,533	92,738	—	696,271
Goodwill	—	323,678	44,894	—	368,572
Equity method investment in joint ventures	—	—	248,301	—	248,301
Long term portion of derivative assets	—	2,270	—	—	2,270
Long term notes receivable	—	—	1,852,928	(1,852,928)	—
Equity investments	3,186,938	1,487,358	—	(4,674,296)	—
Other assets, net	41,094	1,787	3,580	—	46,461
Total assets	3,993,483	3,195,006	$4,434,052	(7,294,696)	$4,327,845
Liabilities and Equity					
Accounts payable – affiliates	$ —	$ 423,078	$ 345,070	$ (765,236)	$ 2,912
Other current liabilities	26,819	75,031	215,464	—	317,314
Total current liabilities	26,819	498,109	560,534	(765,236)	320,226
Long-term portion of derivative liabilities	—	320	—	—	320
Long-term debt, less current portion	1,706,556	230	—	—	1,706,786
Deferred income taxes, net	—	33,290	—	—	33,290
Other long-term liability	203	1,115	6,000	—	7,318
Equity	2,259,905	2,661,942	3,867,518	(6,529,460)	2,259,905
Total liabilities and equity	$3,993,483	$3,195,006	$4,434,052	$(7,294,696)	$4,327,845

December 31, 2012	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$ —	$ 157	$ 3,241	$ —	$ 3,398
Accounts receivable – affiliates	921,702	—	—	(921,702)	—
Other current assets	172	68,144	149,507	(1,146)	216,677
Total current assets	921,874	68,301	152,748	(922,848)	220,075
Property, plant and equipment, net	—	491,790	1,708,591	—	2,200,381
Intangible assets, net	—	101,446	97,914	—	199,360
Goodwill	—	278,423	40,862	—	319,285
Equity method investment in joint venture	—	86,002	—	—	86,002
Long term portion of derivative assets	—	7,942	—	—	7,942
Long term notes receivable	—	—	1,852,928	(1,852,928)	—
Equity investments	1,832,652	1,880,155	—	(3,712,807)	—
Other assets, net	30,496	1,772	325	—	32,593
Total assets	$2,785,022	$2,915,831	$3,853,368	$(6,488,583)	$3,065,638
Liabilities and Equity					
Accounts payable – affiliates	$ —	$ 145,436	$ 781,766	$ (921,702)	$ 5,500
Other current liabilities	10,046	61,333	176,640	—	248,019
Total current liabilities	10,046	206,769	958,406	(921,702)	253,519
Long-term debt, less current portion	1,168,415	604	64	—	1,169,083
Deferred income taxes, net	—	30,258	—	—	30,258
Other long-term liability	153	217	6,000	—	6,370
Equity	1,606,408	2,677,983	2,888,898	(5,566,881)	1,606,408
Total liabilities and equity	$2,785,022	$2,915,831	$3,853,368	$(6,488,583)	$3,065,638

Statements of Operations and Comprehensive Income	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2013					
Total revenues	$ —	$ 504,392	$ 1,684,625	$ (82,168)	$ 2,106,849
Total costs and expenses	(86,965)	(610,208)	(1,507,806)	80,955	(2,124,024)
Equity income (loss)	14,954	160,371	(4,736)	(175,325)	(4,736)
Goodwill impairment loss	—	(43,866)	—	—	(43,866)
Loss on early extinguishment of debt	(26,601)	—	—	—	(26,601)
Loss on asset disposition	—	(1,519)	—	—	(1,519)
Income (loss), before tax	(98,612)	9,170	172,083	(176,538)	(93,897)
Income tax benefit	—	(2,260)	—	—	(2,260)
Net income (loss)	(98,612)	11,430	172,083	(176,538)	(91,637)
Income attributable to non-controlling interest	—	—	(6,975)	—	(6,975)
Preferred unit imputed dividend effect	(29,485)	—	—	—	(29,485)
Preferred unit dividends in kind	(23,583)	—	—	—	(23,583)
Net income (loss) attributable to common limited partners and the General Partner	$(151,680)	$ 11,430	$ 165,108	$ (176,538)	$ (151,680)
Year Ended December 31, 2012					
Total revenues	$ —	$ 240,679	$ 1,005,341	$ —	$ 1,246,020
Total costs and expenses	(39,462)	(272,284)	(872,362)	—	(1,184,108)
Equity income (loss)	101,511	139,339	—	(234,527)	6,323
Income (loss), before tax	62,049	107,734	132,979	(234,527)	68,235
Income tax expense	—	176	—	—	176
Net income (loss)	62,049	107,558	132,979	(234,527)	68,059
Income attributable to non-controlling interest	—	—	(6,010)	—	(6,010)
Net income (loss) attributable to common limited partners and the General Partner	62,049	107,558	126,969	(234,527)	62,049
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	4,390	4,390	—	(4,390)	4,390
Comprehensive income (loss)	$ 66,439	$ 111,948	$ 126,969	$ (238,917)	$ 66,439

Statements of Operations and Comprehensive Income	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2011					
Total revenues	$ —	$ 238,047	$1,064,687	$ —	$ 1,302,734
Total costs and expenses	(28,682)	(292,818)	(927,479)	—	(1,248,979)
Equity income (loss)	341,355	139,480	—	(475,810)	5,025
Loss on early extinguishment of debt	(19,574)	—	—	—	(19,574)
Gain on asset sales and other	—	256,272	—	—	256,272
Income (loss) from continuing operations	293,099	340,981	137,208	(475,810)	295,478
Loss from discontinued operations	—	(81)	—	—	(81)
Net income (loss)	293,099	340,900	137,208	(475,810)	295,397
Income attributable to non-controlling interest	—	—	(6,200)	—	(6,200)
Preferred unit dividends	(389)	—	—	—	(389)
Net income (loss) attributable to common limited partners and the General Partner	292,710	340,900	131,008	(475,810)	288,808
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	6,834	6,834	—	(6,834)	6,834
Comprehensive income (loss)	$299,544	$ 347,734	$ 131,008	$ (482,644)	$ 295,642

Statements of Cash Flows	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2013					
Net cash provided by (used in):					
Operating activities	$ (493,139)	$ 136,862	$ 281,141	$ 285,980	$ 210,844
Investing activities	(757,365)	(806,159)	(577,527)	697,968	(1,443,083)
Financing activities	1,250,504	669,308	297,891	(938,948)	1,233,755
Net change in cash and cash equivalents	—	11	1,505	—	1,516
Cash and cash equivalents, beginning of period	—	157	3,241	—	3,398
Cash and cash equivalents, end of period	$ —	$ 168	$ 4,746	$ —	$ 4,914

Statements of Cash Flows	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Year Ended December 31, 2012					
Net cash provided by (used in):					
Operating activities	$(432,255)	$ 133,153	$ 186,494	$ 287,246	$ 174,638
Investing activities	(405,501)	(431,835)	(419,427)	250,122	(1,006,641)
Financing activities	837,756	298,671	236,174	(537,368)	835,233
Net change in cash and cash equivalents	—	(11)	3,241	—	3,230
Cash and cash equivalents, beginning of period	—	168	—	—	168
Cash and cash equivalents, end of period	$ —	$ 157	$ 3,241	$ —	$ 3,398
Year Ended December 31, 2011					
Net cash provided by (used in):					
Operating activities	$(119,307)	$ 49,887	$ 217,057	$ (44,770)	$ 102,867
Continuing investing activities	300,985	295,697	(207,552)	(321,286)	67,844
Discontinued investing activities	—	(81)		—	(81)
Total investing activities	300,985	295,616	(207,552)	(321,286)	67,763
Financing activities	(181,678)	(345,499)	(9,505)	366,056	(170,626)
Net change in cash and cash equivalents	—	4	—	—	4
Cash and cash equivalents, beginning of period	—	164	—	—	164
Cash and cash equivalents, end of period	$ —	$ 168	$ —	$ —	$ 168

NOTE 20 – QUARTERLY FINANCIAL DATA (Unaudited)

	Fourth Quarter(1)	Third Quarter(2)	Second Quarter(3)	First Quarter(4)
	(in thousands, except per unit data)			
Year ended December 31, 2013:				
Revenue	$ 580,128	$ 557,870	$ 560,939	$ 407,912
Costs and expenses	(581,918)	(582,369)	(548,866)	(410,871)
Equity income (loss) in joint ventures	(4,422)	(1,882)	(472)	2,040
Goodwill impairment loss	(43,866)	—	—	—
Loss on asset disposition	—	—	(1,519)	—
Loss on early extinguishment of debt	—	—	(19)	(26,582)
Income tax benefit	1,406	817	28	9
Net income (loss)	(48,672)	(25,564)	10,091	(27,492)
Income attributable to non-controlling interests	(2,282)	(1,514)	(1,810)	(1,369)
Preferred unit imputed dividend effect	(11,378)	(11,378)	(6,729)	—
Preferred unit dividends in kind	(9,170)	(9,072)	(5,341)	—
Net loss attributable to common limited partners and the General Partner	(71,502)	(47,528)	(3,789)	(28,861)
Net loss attributable to common limited partners per unit – basic and diluted(5)(6)	$ (0.94)	$ (0.66)	$ (0.11)	$ (0.48)

(1) Net income includes a $15.4 million non-cash derivative loss.
(2) Net income includes a $23.6 million non-cash derivative loss.
(3) Net income includes a $24.3 million non-cash derivative gain.
(4) Net income includes a $13.7 million non-cash derivative loss.
(5) For the fourth, third, second, and first quarters of the year ended December 31, 2013, approximately 1,476,000, 1,455,000, 967,000, and 1,055,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.
(6) For the fourth, third, and second quarters of the year ended December 31, 2013, approximately 13,709,000, 13,518,000, and 9,013,000 weighted average Class D Preferred Units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit as the impact of the conversion would have been anti-dilutive.

	Fourth Quarter(1)	Third Quarter(2)	Second Quarter(3)	First Quarter(4)
	(in thousands, except per unit data)			
Year ended December 31, 2012:				
Revenue	$ 352,052	$ 277,568	$ 324,114	$ 292,286
Costs and expenses	(360,871)	(285,346)	(251,180)	(286,711)
Equity income in joint venture	2,088	1,422	1,917	896
Income tax expense	(176)	—	—	—
Net income (loss)	(6,907)	(6,356)	74,851	6,471
Income attributable to non-controlling interests	(1,902)	(1,511)	(1,061)	(1,536)
Net income (loss) attributable to common limited partners and the General Partner	(8,809)	(7,867)	73,790	4,935
Net income (loss) attributable to common limited partners per unit – basic and diluted(5)	$ (0.22)	$ (0.17)	$ 1.30	$ 0.06

(1) Net income includes an $8.3 million non-cash derivative loss.
(2) Net income includes a $22.5 million non-cash derivative loss.
(3) Net income includes a $64.7 million non-cash derivative gain.
(4) Net income includes a $10.7 million non-cash derivative loss.
(5) For the fourth and third quarter of the year ended December 31, 2012, approximately 1,022,000 and 964,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.

NOTE 21 – SUBSEQUENT EVENTS

On January 28, 2014, the Partnership declared a cash distribution of $0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. The $56.1 million distribution, including $6.1 million to the General Partner for its general partner interest and incentive distribution rights, was paid on February 14, 2014 to unitholders of record at the close of business on February 7, 2014 (see Note 5). Based on this declaration, the Partnership also issued 274,785 Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution in kind for the quarter ended December 31, 2013.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)
(Unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,074	$ 4,914
Accounts receivable	254,953	219,297
Current portion of derivative assets	—	174
Prepaid expenses and other	26,549	17,393
Total current assets	285,576	241,778
Property, plant and equipment, net	2,984,168	2,724,192
Goodwill	365,763	368,572
Intangible assets, net	634,086	696,271
Equity method investment in joint ventures	179,054	248,301
Long-term portion of derivative assets	451	2,270
Other assets, net	43,931	46,461
Total assets	$4,493,029	$4,327,845
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 320	$ 524
Accounts payable – affiliates	4,302	2,912
Accounts payable	124,074	79,051
Accrued liabilities	52,810	47,449
Accrued interest payable	26,746	26,737
Current portion of derivative liabilities	11,454	11,244
Accrued producer liabilities	179,843	152,309
Total current liabilities	399,549	320,226
Long-term portion of derivative liabilities	216	320
Long-term debt, less current portion	1,654,319	1,706,786
Deferred income taxes, net	32,394	33,290
Other long-term liabilities	7,011	7,318
Commitments and contingencies		
Equity:		
Class D convertible preferred limited partners' interests	493,630	450,749
Class E preferred limited partners' interests	121,852	—
Common limited partners' interests	1,666,438	1,703,778
General Partner's interest	45,840	46,118
Total partners' capital	2,327,760	2,200,645
Non-controlling interest	71,780	59,260
Total equity	2,399,540	2,259,905
Total liabilities and equity	$4,493,029	$4,327,845

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)
(Unaudited)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenue:				
Natural gas and liquids sales	$667,549	$491,230	$1,330,679	$875,078
Transportation, processing and other fees – third parties	49,952	40,229	93,334	72,883
Transportation, processing and other fees – affiliates	91	77	146	148
Derivative gain (loss), net	(6,367)	27,107	(15,038)	15,024
Other income, net	2,731	2,296	4,839	5,718
Total revenues	713,956	560,939	1,413,960	968,851
Costs and expenses:				
Natural gas and liquids cost of sales	580,885	424,216	1,156,353	749,756
Operating expenses	26,983	24,770	52,111	46,629
General and administrative	17,166	11,296	33,856	23,844
Compensation reimbursement – affiliates	1,250	1,250	2,500	2,500
Other (revenues) costs	(20)	18,370	17	18,900
Depreciation and amortization	49,220	46,383	98,459	76,841
Interest	23,059	22,581	46,722	41,267
Total costs and expenses	698,543	548,866	1,390,018	959,737
Equity income (loss) in joint ventures	(3,875)	(472)	(5,753)	1,568
Gain (loss) on asset dispositions	48,465	(1,519)	48,465	(1,519)
Loss on early extinguishment of debt	—	(19)	—	(26,601)
Income (loss) before tax	60,003	10,063	66,654	(17,438)
Income tax benefit	(498)	(28)	(896)	(37)
Net income (loss)	60,501	10,091	67,550	(17,401)
Income attributable to non-controlling interests	(3,965)	(1,810)	(6,427)	(3,179)
Preferred unit imputed dividend effect	(11,378)	(6,729)	(22,756)	(6,729)
Preferred unit dividends in kind	(10,406)	(5,341)	(20,125)	(5,341)
Preferred unit dividends	(2,609)	—	(3,015)	—
Net income (loss) attributable to common limited partners and the General Partner	$ 32,143	$ (3,789)	$ 15,227	$ (32,650)
Allocation of net income (loss) attributable to:				
Common limited partner interest	$ 25,740	$ (8,408)	$ 4,296	$ (39,614)
General Partner interest	6,403	4,619	10,931	6,964
	$ 32,143	$ (3,789)	$ 15,227	$ (32,650)
Net income (loss) attributable to common limited partners per unit:				
Basic	$ 0.27	$ (0.11)	$ 0.04	$ (0.57)
Weighted average common limited partner units (basic)	80,979	74,340	80,788	69,520
Diluted	$ 0.27	$ (0.11)	$ 0.04	$ (0.57)
Weighted average common limited partner units (diluted)	96,890	74,340	96,498	69,520

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(in thousands, except unit data)
(Unaudited)

	Class D Preferred Limited Partner Units	Class E Preferred Limited Partner Units	Common Limited Partner Units	Class D Preferred Limited Partners	Class E Preferred Limited Partners	Common Limited Partners	General Partner	Non-controlling Interest	Total
Balance at December 31, 2013	13,823,869	—	80,585,148	$450,749	$ —	$1,703,778	$ 46,118	$ 59,260	$2,259,905
Issuance of units and General Partner capital contribution	—	5,060,000	1,462,187	—	122,258	47,421	985	—	170,664
Issuance of common units under incentive plans	—	—	115,632	—	—	91	—	—	91
Unissued common units under incentive plans	—	—	—	—	—	12,731	—	—	12,731
Distributions paid in kind units	580,768	—	—	—	—	—	—	—	—
Distributions paid	—	—	—	—	—	(101,879)	(12,194)	—	(114,073)
Distributions payable	—	—	—	—	(3,421)	—	—	—	(3,421)
Contributions from non-controlling interests	—	—	—	—	—	—	—	7,880	7,880
Distributions to non-controlling interests	—	—	—	—	—	—	—	(1,787)	(1,787)
Net income	—	—	—	42,881	3,015	4,296	10,931	6,427	67,550
Balance at June 30, 2014	14,404,637	5,060,000	82,162,967	$493,630	$121,852	$1,666,438	$ 45,840	$ 71,780	$2,399,540

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 67,550	$ (17,401)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	98,459	76,841
Equity (income) loss in joint ventures	5,753	(1,568)
Distributions received from equity method joint ventures	4,200	3,600
Non-cash compensation expense	12,882	7,820
Amortization of deferred finance costs	3,730	3,283
Loss on early extinguishment of debt	—	26,601
Loss (gain) on asset dispositions	(48,465)	1,519
Income tax benefit	(896)	(37)
Change in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	(44,604)	(57,274)
Accounts payable and accrued liabilities	37,811	38,982
Accounts payable and accounts receivable – affiliates	1,390	(1,933)
Derivative accounts payable and receivable	2,099	(8,712)
Net cash provided by operating activities	139,909	71,721
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(280,579)	(215,709)
Cash paid for business combinations, net of cash received	—	(1,000,785)
Net proceeds from asset disposition	132,666	—
Capital contributions to joint ventures	(1,649)	—
Other	(850)	250
Net cash used in investing activities	$(150,412)	$(1,216,244)

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS CONTINUED
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
	2014	2013
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	$ 503,500	$ 865,000
Repayments under credit facility	(555,500)	(1,078,000)
Net proceeds from issuance of long term debt	—	1,028,449
Repayment of long-term debt	—	(365,822)
Payment of premium on retirement of debt	—	(25,581)
Payment of deferred financing costs	(350)	(893)
Payment for acquisition-based contingent consideration	—	(6,000)
Principal payments on capital lease	(333)	(10,578)
Net proceeds from issuance of common and preferred limited partner units	169,679	825,235
General Partner capital contributions	985	17,280
Contributions from non-controlling interest holders	7,880	5,176
Distributions to non-controlling interest holders	(1,787)	(500)
Distributions paid to common limited partners and the General Partner	(114,073)	(91,115)
Other	(338)	(445)
Net cash provided by financing activities	9,663	1,162,206
Net change in cash and cash equivalents	(840)	17,683
Cash and cash equivalents, beginning of period	4,914	3,398
Cash and cash equivalents, end of period	$ 4,074	$ 21,081

See accompanying notes to consolidated financial statements

NOTE 1 – BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the “Partnership”) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States and natural gas gathering services in the Appalachian Basin in the northeastern region of the United States. The Partnership’s operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the “Operating Partnership”), a majority-owned subsidiary of the Partnership. At June 30, 2014, Atlas Pipeline Partners GP, LLC (the “General Partner”) owned a combined 2.0% general partner interest in the consolidated operations of the Partnership, through which it manages and effectively controls both the Partnership and the Operating Partnership. The General Partner is a wholly-owned subsidiary of Atlas Energy, L.P. (“ATLS”), a publicly-traded limited partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations of the Partnership consists of limited partner interests. At June 30, 2014, the Partnership had 82,162,967 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS; 14,404,637 Class D convertible preferred units (“Class D Preferred Units”) outstanding (see Note 5); and 5,060,000 8.25% Class E cumulative redeemable perpetual preferred units (“Class E Preferred Units”) outstanding (see Note 5).

The accompanying consolidated financial statements, which are unaudited, except the balance sheet dated December 31, 2013, which is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States for interim reporting. The accompanying consolidated financial statements and notes thereto do not include all disclosures normally made in financial statements contained in Form 10-K. In management’s opinion, all adjustments necessary for a fair presentation of the Partnership’s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2013. Certain amounts in the prior year’s consolidated financial statements have been reclassified to conform to the current year presentation. The results of operations for the six month period ended June 30, 2014 may not necessarily be indicative of the results of operations for the full year ending December 31, 2014.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership’s significant accounting policies is included in its audited consolidated financial statements and notes thereto in its Annual Report on Form 10-K for the year ended December 31, 2013.

Principles of Consolidation and Non-Controlling Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership, a variable interest entity of which the Partnership is the primary beneficiary, and the Operating Partnership’s wholly-owned and majority-owned subsidiaries. The General Partner’s interest in the Operating Partnership is reported as part of its overall 2.0% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as “other comprehensive income (loss).” The Partnership does not have any type of transaction, which would be included within other comprehensive income (loss), thus comprehensive income (loss) is equal to net income (loss).

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner’s and the preferred unitholders’ interests. The General Partner’s interest in net income (loss) is calculated on a quarterly basis based upon its 2.0% general partner interest and incentive distributions to be distributed for the quarter (see Note 5), with a priority allocation of net income to the General Partner’s incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner’s and limited partners’ ownership interests.

The Partnership presents net income (loss) per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights’ share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management of the Partnership believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership’s phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 15), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award’s vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. Therefore, the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the phantom units on a pro-rata basis.

Class D Preferred Units participate in distributions with the common limited partner units according to a predetermined formula (see Note 5), thus they are considered participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution.

However, the contractual terms of the Class D Preferred Units do not require the holders to share in the losses of the entity, therefore the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the Class D Preferred Units on a pro-rata basis.

Class E Preferred Units do not participate in distributions with the common limited partner units according to a predetermined formula, but rather receive distributions based upon a set percentage rate (see Note 5), thus they are not considered participating securities. However, income available to common limited partners is reduced by the distributions accumulated for the period on the Class E Preferred Units, whether declared or not since the distributions on Class E Preferred Units are cumulative.

The following is a reconciliation of net income (loss) allocated to the General Partner and common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$ 60,501	$10,091	$ 67,550	$(17,401)
Income attributable to non-controlling interests	(3,965)	(1,810)	(6,427)	(3,179)
Preferred unit imputed dividend effect	(11,378)	(6,729)	(22,756)	(6,729)
Preferred unit dividends in kind	(10,406)	(5,341)	(20,125)	(5,341)
Preferred unit dividends	(2,609)	—	(3,015)	—
Net income (loss) attributable to common limited partners and the General Partner	32,143	(3,789)	15,227	(32,650)
General Partner’s cash incentive distributions	5,875	4,790	10,843	7,776
General Partner’s ownership interest	528	(171)	88	(812)
Net income attributable to the General Partner’s ownership interests	6,403	4,619	10,931	6,964
Net income (loss) attributable to common limited partners	25,740	(8,408)	4,296	(39,614)
Net income attributable to participating securities – phantom units(1)	440	—	71	—
Net income attributable to participating securities – Class D Preferred Units(2)	3,826	—	635	—
Net income attributable to participating securities	4,266	—	706	—
Net income (loss) utilized in the calculation of net loss attributable to common limited partners per unit	$ 21,474	$ (8,408)	$ 3,590	$(39,614)

(1) Net loss attributable to common limited partners’ ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three and six months ended June 30, 2013, net loss attributable to common limited partners’ ownership interest is not allocated to approximately 967,000 and 1,011,000 weighted average phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

(2) Net loss attributable to common limited partners’ ownership interest is allocated to the Class D Preferred Units on a pro-rata basis (weighted average Class D Preferred Units outstanding, plus a contractual yield premium of 1%, as a percentage of the sum of the weighted average Class D Preferred Units and common limited partner units outstanding). For the three and six months ended June 30, 2013, net loss attributable to common limited partners’ ownership interest is not allocated to approximately 9,013,000 and 4,531,000 weighted average Class D Preferred Units, respectively, because the contractual terms of the Class D Preferred Units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities and the effects of outstanding convertible securities. The phantom units and Class D Preferred Units are participating securities included in the calculation of diluted net income (loss) attributable to common units, due to their participation rights and due to their dilution if converted. The Class E Preferred Units are not participating securities and are not convertible and thus are not included in the units outstanding for calculation of diluted net income (loss) attributable to common limited partners per unit.

The following table sets forth the reconciliation of the Partnership's weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Weighted average number of common limited partner units – basic	80,979	74,340	80,788	69,520
Add effect of dilutive securities – phantom units(1)	1,654	—	1,599	—
Add effect of convertible preferred limited partner units(2)	14,257	—	14,111	—
Weighted average common limited partner units – diluted	96,890	74,340	96,498	69,520

(1) For the three and six months ended June 30, 2013, approximately 967,000 and 1,011,000 weighted average phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.

(2) For the three and six months ended June 30, 2013, approximately 9,013,000 and 4,531,000 weighted average Class D Preferred Units, respectively, were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

Revenue Recognition

The Partnership accrues unbilled revenue and the related purchase costs due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership's records and management estimates of the related gathering and compression fees and applicable product prices. The Partnership had unbilled revenues at June 30, 2014 and December 31, 2013 of $179.5 million and $134.9 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments. Checks outstanding at the end of a period that exceed available cash balances held at the bank are considered to be book overdrafts and are reclassified to accounts payable. At June 30, 2014 and December 31, 2013, the Partnership reclassified the balances related to book overdrafts of $23.0 million and $28.8 million, respectively, from cash and cash equivalents to accounts payable on the Partnership's consolidated balance sheets.

Recently Adopted Accounting Standards

In July 2013, the FASB issued Accounting Standard Update ("ASU") 2013-11, "Income Taxes (Topic 740) – Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists," which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership applied these requirements upon the adoption of the ASU on January 1, 2014. The adoption had no material impact on the Partnership's financial position or results of operations.

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)." ASU 2014-09 will supersede the revenue recognition requirements in Topic 605 "Revenue Recognition", and most industry-specific guidance. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

The amendments in ASU 2014-09 are effective for interim and annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. An entity should apply the amendments in this ASU using one of the following methods: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect of initially applying the standard recognized at the date of initial application.

The Partnership will apply these requirements upon the adoption of ASU 2014-09 on January 1, 2017. The Partnership is currently in the process of evaluating which method to use for application of ASU 2014-09 and is still determining the impacts of ASU 2014-09 on its financial position, results of operations and disclosures.

NOTE 3 – ACQUISITIONS

On May 7, 2013, the Partnership completed the acquisition of 100% of the equity interests of TEAK Midstream, LLC ("TEAK") for $974.7 million in cash, including final purchase price adjustments, less cash received (the "TEAK Acquisition"). The assets of these companies include gas gathering and processing facilities in Texas. The acquisition included a 75% interest in T2 LaSalle Gathering Company L.L.C. ("T2 LaSalle"); a 50% interest in T2 Eagle Ford Gathering Company L.L.C. ("T2 Eagle Ford"); and a 50% interest in T2 EF Cogeneration Holdings L.L.C. ("T2 Co-Gen" and together with T2 Eagle Ford and T2 LaSalle, the "T2 Joint Ventures").

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their acquisition date fair values. The following table presents the values assigned to the assets acquired and liabilities assumed in the TEAK Acquisition, based on their final estimated fair values at the date of the acquisition (in thousands):

Cash	$ 8,074
Accounts receivable	11,055
Prepaid expenses and other	1,626
Property, plant and equipment	197,683
Intangible assets	430,000
Goodwill	186,050
Equity method investment in joint ventures	184,327
Total assets acquired	1,018,815
Accounts payable and accrued liabilities	(34,995)
Other long term liabilities	(1,075)
Total liabilities acquired	(36,070)
Net assets acquired	**982,745**
Less cash received	(8,074)
Net cash paid for acquisition	**$ 974,671**

NOTE 4 – EQUITY METHOD INVESTMENTS

West Texas LPG Pipeline Limited Partnership

On May 14, 2014, the Partnership completed the sale of two indirect subsidiaries, which held an aggregate 20% interest in West Texas LPG Pipeline Limited Partnership (“WTLPG”), to a subsidiary of Martin Midstream Partners L.P. (NYSE: MMLP). The Partnership received $132.7 million in proceeds, net of selling costs, which were used to pay down the Partnership’s revolving credit facility (see Note 13). As a result of the sale, the Partnership recorded a $48.5 million gain on asset dispositions on its consolidated statements of operations for the three and six months ended June 30, 2014.

WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (NYSE: CVX), which owns the remaining 80% interest. The Partnership accounted for its subsidiaries’ ownership interest in WTLPG under the equity method of accounting, with recognition of income of WTLPG as equity income in joint ventures on its consolidated statements of operations.

T2 Joint Ventures

On May 7, 2013, the Partnership acquired a 75% interest in T2 LaSalle, a 50% interest in T2 Eagle Ford and a 50% interest in T2 EF Co-Gen as part of the TEAK Acquisition (see Note 3). The T2 Joint Ventures are operated by TexStar Midstream Services, L.P. (“TexStar”), the investor owning the remaining interests. The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The Partnership accounts for its investments in the joint ventures under the equity method of accounting.

The Partnership evaluated whether the T2 Joint Ventures should be subject to consolidation. The T2 Joint Ventures do meet the qualifications of a Variable Interest Entity (“VIE”), but the Partnership does not meet the qualifications as the primary beneficiary. Even though the Partnership owns a 50% or greater interest in the T2 Joint Ventures, the Partnership does not have controlling financial interests in these entities. Since the Partnership shares equal management rights with TexStar, and TexStar is the operator of the T2 Joint Ventures, the Partnership determined that it is not the primary beneficiary of the VIEs and should not consolidate the T2 Joint Ventures. The Partnership accounts for its investment in the T2 Joint Ventures under the equity method, since the Partnership does not have a controlling financial interest, but does have a significant influence. The Partnership's maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment, any additional capital contribution commitments and the Partnership's share of any approved operating expenses incurred by the VIEs.

The following table presents the value of the Partnership's equity method investments in joint ventures as of June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013
WTLPG	$ —	$ 85,790
T2 LaSalle	57,578	50,534
T2 Eagle Ford	107,314	97,437
T2 EF Co-Gen	14,162	14,540
Equity method investment in joint ventures	$179,054	$ 248,301

The following table presents the Partnership's equity income (loss) in joint ventures for the three and six months ended June 30, 2014 and 2013 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
WTLPG	$ 884	$ 1,687	$ 2,611	$ 3,727
T2 LaSalle	(1,364)	(898)	(2,477)	(898)
T2 Eagle Ford	(2,693)	(1,078)	(4,738)	(1,078)
T2 EF Co-Gen	(702)	(183)	(1,149)	(183)
Equity income (loss) in joint ventures	$(3,875)	$ (472)	$(5,753)	$ 1,568

NOTE 5 – EQUITY

Common Units

On May 12, 2014, the Partnership entered into an Equity Distribution Agreement (the "2014 EDA") with Citigroup Global Markets Inc. ("Citigroup"), Wells Fargo Securities, LLC and MLV & Co. LLC (together, the "Sales Agents"). Pursuant to the 2014 EDA, the Partnership may offer and sell from time to time through its Sales Agents, common units having an aggregate value up to $250.0 million. Sales are at market prices prevailing at the time of the sale.

In November 2012, the Partnership entered into an Equity Distribution Agreement (the "2012 EDA", and together with the 2014 EDA, the "EDAs") with Citigroup. Pursuant to this program, the Partnership offered and sold through Citigroup, as its sales agent, common units for $150.0 million. The Partnership used the full capacity under the 2012 EDA during the year ended 2013.

During the three months ended June 30, 2014 and 2013, the Partnership issued 1,462,187 and 642,495 common units, respectively, under the EDAs for net proceeds of $47.4 million and $24.5 million, respectively, net of $0.5 million and $0.5 million, respectively, in commissions paid to the Sales Agents. During the six months ended June 30, 2014 and 2013, the Partnership issued 1,462,187 and 1,090,280 common units, respectively, under the EDAs for net proceeds of $47.4 million and $38.9 million, respectively, net of $0.5 million and $0.8 million, respectively, in commissions paid to the Sales Agents. The Partnership also received capital contributions from the General Partner of $1.0 million and $0.5 million, respectively, during the three months ended June 30, 2014 and 2013, and $1.0 million and $0.8 million, respectively, during the six months ended June 30, 2014 and 2013, to maintain its 2.0% general partner interest in the Partnership. The net proceeds from the common unit offerings were utilized for general partnership purposes.

Cash Distributions

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders (subject to the rights of any other class or series of the Partnership's securities with the right to share in the Partnership's cash distributions) and to the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels, including the General Partner's 2.0% interest. The General Partner, which holds all the incentive distribution rights in the Partnership, has agreed to allocate up to $3.75 million of its incentive distribution rights per quarter back to the Partnership after the General Partner receives the initial $7.0 million per quarter of incentive distribution rights.

Common unit and General Partner distributions declared by the Partnership for quarters ending from March 31, 2013 through March 31, 2014 were as follows:

For Quarter Ended	Date Cash Distribution Paid	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
March 31, 2013	May 15, 2013	$ 0.59	$ 45,382	$ 3,980
June 30, 2013	August 14, 2013	0.62	48,165	5,875
September 30, 2013	November 14, 2013	0.62	49,298	6,013
December 31, 2013	February 14, 2014	0.62	49,969	6,095
March 31, 2014	May 15, 2014	0.62	49,998	6,099

On July 23, 2014, the Partnership declared a cash distribution of $0.63 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2014. The $58.8 million distribution, including $7.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2014 to unitholders of record at the close of business on August 7, 2014.

Class D Preferred Units

The Partnership's Class D Preferred Units are presented combined with a net $38.8 million unaccreted beneficial conversion discount on the Partnership's consolidated balance sheets as of June 30, 2014. The Partnership recorded $11.4 million and $6.7 million for the three months ended June 30, 2014 and 2013, respectively, and $22.8 million and $6.7 million for the six months ended June 30, 2014 and 2013, respectively, within preferred unit imputed dividend effect on the Partnership's consolidated statements of operations to recognize the accretion of the beneficial conversion discount.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance in May 2013, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of the General Partner. The Partnership recorded Class D Preferred Unit distributions in kind of $10.4 million and $5.3 million for the three months ended June 30, 2014 and 2013, respectively, and $20.1 million and $5.3 million for the six months ended June 30, 2014 and 2013, respectively, as preferred unit dividends in kind on the Partnership's consolidated statements of operations. During the three and six months ended June 30, 2014, the Partnership distributed 305,983 and 580,768, respectively, Class D Preferred Units to the holders of the Class D Preferred Units. The Partnership did not distribute any Class D Preferred Units during the three and six months ended June 30, 2013. The Partnership considers preferred unit distributions paid in kind to be a non-cash financing activity.

On July 23, 2014, the Partnership declared a cash distribution of $0.63 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2014. Based on this declaration, on August 14, 2014, the Partnership will issue approximately 305,000 Class D Preferred Units as a preferred unit distribution in kind for the quarter ended June 30, 2014 to the preferred unitholders of record at the close of business on August 7, 2014.

Class E Preferred Units

On March 17, 2014, the Partnership issued 5,060,000 of its Class E Preferred Units to the public at an offering price of $25.00 per Class E Preferred Unit. The Partnership received $122.3 million in net proceeds. The proceeds were used to pay down the Partnership's revolving credit facility.

The Partnership will make cumulative cash distributions on the Class E Preferred Units from the date of original issue. The cash distributions will be payable quarterly in arrears on January 15, April 15, July 15, and October 15 of each year, when, and if, declared by the board of directors. The initial distribution on the Class E Preferred Units was paid on July 15, 2014 in an amount equal to $0.67604 per unit, or approximately $3.4 million, representing the distribution for the period March 17, 2014 to July 14, 2014. Going forward, the Partnership will pay cumulative distributions in cash on the Class E Preferred Units on a quarterly basis at a rate of $0.515625 per unit, or 8.25% per year. For the three and six months ended June 30, 2014, the Partnership allocated net income of $2.6 million and $3.0 million, respectively, to the Class E Preferred Units for the dividends earned during the period, which was recorded as preferred unit dividends on its consolidated statements of operations.

At any time on or after March 17, 2019, or in the event of a liquidation or certain changes of control, the Partnership may redeem the Class E Preferred Units, in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions on the date of redemption, whether or not declared. If the Partnership does not exercise this redemption right upon a change of control, then the holders of the Class E Preferred Units will have the option to convert their Class E Preferred Units into a number of the Partnership's common units, as set forth in the Certificate of Designation relating to the Class E Preferred Units.

NOTE 6 – PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 13) (in thousands):

	June 30, 2014	December 31, 2013	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$3,202,816	$ 2,885,303	2 – 40
Rights of way	201,860	203,136	20 – 40
Buildings	10,447	10,291	40
Furniture and equipment	13,811	13,800	3 – 7
Other	15,165	15,805	3 – 10
	3,444,099	3,128,335	
Less – accumulated depreciation	(459,931)	(404,143)	
	$2,984,168	$ 2,724,192	

The Partnership recorded depreciation expense on property, plant and equipment, including capital lease arrangements (see Note 13), of $28.5 million and $24.2 million for the three months ended June 30, 2014 and 2013, respectively, and $56.3 million and $46.5 million for the six months ended June 30, 2014 and 2013, respectively, on its consolidated statements of operations.

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds was 5.6% and 5.8% for the three months ended June 30, 2014 and 2013, respectively, and 5.6% and 6.0% for the six months ended June 30, 2014 and 2013, respectively. The amount of interest capitalized was $3.2 million and $1.3 million for the three months ended June 30, 2014 and 2013, respectively, and $6.1 million and $3.8 million for the six months ended June 30, 2014 and 2013, respectively.

NOTE 7 – GOODWILL AND INTANGIBLE ASSETS

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. Impairment testing for goodwill is done at the reporting unit level. A reporting unit is an operating segment or one level below an operating segment (also known as a component). The Partnership evaluates goodwill for impairment annually, on December 31, for all reporting units, except SouthTX, which is evaluated on April 30. The Partnership tested the SouthTX reporting unit goodwill for impairment as of April 30, 2014. The results indicated the fair value of the SouthTX reporting unit was higher than its carrying value, and thus, goodwill recorded on the SouthTX reporting unit was not impaired as of April 30, 2014. The following table reflects the carrying amounts of goodwill by reporting unit at June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013
Carrying amount of goodwill by reporting unit:		
Barnett system	$ 951	$ 951
SouthOK system	170,381	170,381
SouthTX system	186,050	188,859
WestOK system	8,381	8,381
	$365,763	$ 368,572

The change in goodwill is related to a $2.8 million decrease in goodwill related to an adjustment of the fair value of assets acquired and liabilities assumed from the TEAK Acquisition (See Note 3). The Partnership expects all goodwill recorded to be deductible for tax purposes.

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	$ 3,419	$ 3,419	2 – 10
Customer relationships	867,653	887,653	7 – 15
	871,072	891,072	
Accumulated amortization:			
Customer contracts	(1,030)	(779)	
Customer relationships	(235,956)	(194,022)	
	(236,986)	(194,801)	
Net carrying amount:			
Customer contracts	2,389	2,640	
Customer relationships	631,697	693,631	
Net carrying amount	$ 634,086	$ 696,271	

The weighted-average amortization period for customer contracts and customer relationships, as of June 30, 2014, is 9.7 years and 11.5 years, respectively. The Partnership recorded amortization expense on intangible assets of $20.7 million and $22.2 million for the three months ended June 30, 2014 and 2013, respectively, and $42.2 million and $30.3 million for the six months ended June 30, 2014 and 2013, respectively, on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: remainder of 2014 – $37.8 million; 2015 through 2016 – $74.0 million per year; 2017 – $68.0 million per year; 2018 – $59.5 million.

NOTE 8 – OTHER ASSETS

The following is a summary of other assets (in thousands):

	June 30, 2014	December 31, 2013
Deferred finance costs, net of accumulated amortization of $25,764 and $22,034 at June 30, 2014 and December 31 2013, respectively	$37,714	$ 41,094
Security deposits	6,217	5,367
	$43,931	$ 46,461

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). The Partnership incurred $0.1 million and $9.4 million of deferred finance costs during the three months ended June 30, 2014 and 2013, respectively, and $0.3 million and $22.4 million deferred finance costs during the six months ended June 30, 2014 and 2013, respectively, related to various financing activities (see Note 13).

During the six months ended June 30, 2013, the Partnership redeemed all of its outstanding $365.8 million 8.75% unsecured senior notes due June 15, 2018 ("8.75% Senior Notes") (see Note 13) and recognized $5.3 million of accelerated amortization of deferred financing costs, included in loss on early extinguishment of debt on the Partnership's consolidated statement of operations. There was no accelerated amortization of deferred financing costs during the six months ended June 30, 2014. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was $1.9 million and $1.7 million for the three months ended June 30, 2014 and 2013, respectively, and $3.7 million and $3.3 million for the six months ended June 30, 2014 and 2013, respectively, which is recorded within interest expense on the Partnership's consolidated statements of operations.

NOTE 9 – INCOME TAXES

The Partnership owns APL Arkoma, Inc., a taxable subsidiary. The components of the federal and state income tax benefit of the Partnership's taxable subsidiary for the three and six months ended June 30, 2014 and 2013 are summarized as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Income tax benefit:				
Federal	$ (446)	$ (25)	$ (803)	$ (33)
State	(52)	(3)	(93)	(4)
Total income tax benefit	$ (498)	$ (28)	$ (896)	$ (37)

The components of net deferred tax liabilities as of June 30, 2014 and December 31, 2013 consist of the following (in thousands):

	June 30, 2014	December 31, 2013
Deferred tax assets:		
Net operating loss tax carryforwards and alternative minimum tax credits	$ 16,198	$ 14,900
Deferred tax liabilities:		
Excess of asset carrying value over tax basis	(48,592)	(48,190)
Net deferred tax liabilities	$(32,394)	$ (33,290)

As of June 30, 2014, the Partnership had net operating loss carry forwards for federal income tax purposes of approximately $41.9 million, which expire at various dates from 2029 to 2034. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 10 – DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price risk management activities. The Partnership uses financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. Due to the right of setoff, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty.

The following tables summarize the Partnership's gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets and liabilities on the Partnership's consolidated balance sheets for the periods indicated (in thousands):

Offsetting of Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
As of June 30, 2014:			
Long-term portion of derivative assets	$ 1,365	$ (914)	$ 451
Current portion of derivative liabilities	2,478	(2,478)	—
Long-term portion of derivative liabilities	1,651	(1,651)	—
Total derivative assets, net	$ 5,494	$ (5,043)	$ 451
As of December 31, 2013:			
Current portion of derivative assets	$ 1,310	$ (1,136)	$ 174
Long-term portion of derivative assets	5,082	(2,812)	2,270
Current portion of derivative liabilities	1,612	(1,612)	—
Long-term portion of derivative liabilities	949	(949)	—
Total derivative assets, net	$ 8,953	$ (6,509)	$ 2,444

Offsetting of Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
As of June 30, 2014:			
Long-term portion of derivative assets	$ (914)	$ 914	$ —
Current portion of derivative liabilities	(13,932)	2,478	(11,454)
Long-term portion of derivative liabilities	(1,867)	1,651	(216)
Total derivative liabilities, net	$ (16,713)	$ 5,043	$ (11,670)
As of December 31, 2013:			
Current portion of derivative assets	$ (1,136)	$ 1,136	$ —
Long-term portion of derivative assets	(2,812)	2,812	—
Current portion of derivative liabilities	(12,856)	1,612	(11,244)
Long-term portion of derivative liabilities	(1,269)	949	(320)
Total derivative liabilities, net	$ (18,073)	$ 6,509	$ (11,564)

The following table summarizes the Partnership's commodity derivatives as of June 30, 2014, (fair value and volumes in thousands):

Production Period	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Sold fixed price swaps				
2014	Natural gas	10,400	$ 4.11	$ (3,611)
2015	Natural gas	19,510	4.27	495
2016	Natural gas	8,100	4.28	48
2017	Natural gas	1,200	4.47	(72)
2014	NGLs	38,052	1.24	(3,132)
2015	NGLs	68,166	1.21	(2,472)
2016	NGLs	9,450	1.03	(84)
2014	Crude oil	159	92.09	(1,828)
2015	Crude oil	210	90.26	(1,597)
2016	Crude oil	30	90.00	(73)
Total fixed price swaps				(12,326)
Purchased put options				
2014	Natural gas	200	4.15	11
2014	NGLs	5,040	0.96	51
2015	NGLs	3,150	0.94	88
2014	Crude oil	207	90.85	120
2015	Crude oil	270	89.18	866
Sold call options				
2014	NGLs	2,520	1.32	(5)
2015	NGLs	1,260	1.28	(24)
Total options				1,107
Total derivatives				$ (11,219)

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.
(2) See Note 11 for discussion on fair value methodology.

The following table summarizes the gross effect of all derivative instruments on the Partnership's consolidated statements of operations for the periods indicated (in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Derivatives not designated as hedges				
Gain (loss) recognized in derivative gain (loss), net:				
Commodity contract – realized(1)	$ (6,619)	$ 2,844	$ (16,454)	$ 4,480
Commodity contract – unrealized(2)	252	24,263	1,416	10,544
Derivative gain (loss), net	$ (6,367)	$ 27,107	$ (15,038)	$ 15,024

(1) Realized gain (loss) represents the gain or loss incurred when the derivative contract expires and/or is cash settled.

(2) Unrealized gain represents the mark-to-market gain recognized on open derivative contracts, which have not yet settled.

NOTE 11 – FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

Level 1– Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 – Unobservable inputs that reflect the entity's own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Derivative Instruments

At June 30, 2014, the valuations for all the Partnership's derivative contracts are defined as Level 2 assets and liabilities within the same class of nature and risk, with the exception of the Partnership's NGL fixed price swaps and NGL options, which are defined as Level 3 assets and liabilities within the same class of nature and risk.

The Partnership's Level 2 commodity derivatives include natural gas and crude oil swaps and options, which are calculated based upon observable market data related to the change in price of the underlying commodity. These swaps and options are calculated by utilizing the New York Mercantile Exchange ("NYMEX") quoted prices for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Valuations for the Partnership's NGL options are based on forward price curves developed by financial institutions, and therefore are defined as Level 3. The NGL options are over-the-counter instruments that are not actively traded in an open market, thus the Partnership utilizes the valuations provided by the financial institutions that provide the NGL options for trade. The Partnership tests these valuations for reasonableness through the use of an internal valuation model.

Valuations for the Partnership's NGL fixed price swaps are based on forward price curves provided by a third party, which the Partnership considers to be Level 3 inputs. The prices are adjusted based upon the relationship between the prices for the product/locations quoted by the third party and the underlying product/locations utilized for the swap contracts, as determined by a regression model of the historical settlement prices for the different product/locations. The regression model is recalculated on a quarterly basis. This adjustment is an unobservable Level 3 input. The NGL fixed price swaps are over-the-counter instruments which are not actively traded in an open market. However, the prices for the underlying products and locations do have a direct correlation to the prices for the products and locations provided by the third party, which are based upon trading activity for the products and locations quoted. A change in the relationship between these prices would have a direct impact upon the unobservable adjustment utilized to calculate the fair value of the NGL fixed price swaps.

The following table represents the Partnership's derivative assets and liabilities recorded at fair value as of June 30, 2014 and December 31, 2013 (in thousands):

	Level 1	Level 2	Level 3	Total
June 30, 2014				
Assets				
Commodity swaps	$ —	$ 2,595	$ 1,763	$ 4,358
Commodity options	—	997	139	1,136
Total assets	—	3,592	1,902	5,494
Liabilities				
Commodity swaps	—	(9,233)	(7,451)	(16,684)
Commodity options	—	—	(29)	(29)
Total liabilities	—	(9,233)	(7,480)	(16,713)
Total derivatives	$ —	$(5,641)	$ (5,578)	$(11,219)
December 31, 2013				
Assets				
Commodity swaps	$ —	$ 2,994	$ 1,412	$ 4,406
Commodity options	—	4,337	210	4,547
Total assets	—	7,331	1,622	8,953
Liabilities				
Commodity swaps	—	(4,695)	(13,378)	(18,073)
Total liabilities	—	(4,695)	(13,378)	(18,073)
Total derivatives	$ —	$ 2,636	$(11,756)	$ (9,120)

The Partnership's Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership's Level 3 derivative instruments for the six months ended June 30, 2014 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		NGL Call Options		Total
	Gallons	Amount	Gallons	Amount	Gallons	Amount	Amount
Balance – December 31, 2013	130,158	$(11,966)	6,300	$ 210	—	$ —	$(11,756)
New contracts(1)	31,626	—	5,040	200	5,040	(200)	—
Cash settlements from unrealized gain (loss)(2)(3)	(46,116)	8,447	(3,150)	225	(1,260)	(20)	8,652
Net change in unrealized gain (loss)(2)	—	(2,169)	—	(271)	—	171	(2,269)
Deferred option premium recognition(3)	—	—	—	(225)	—	20	(205)
Balance – June 30, 2014	115,668	$ (5,688)	8,190	$ 139	3,780	$ (29)	$ (5,578)

(1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.
(2) Included within derivative gain (loss), net on the Partnership's consolidated statements of operations.
(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

The following table provides a summary of the unobservable inputs used in the fair value measurement of the Partnership's NGL fixed price swaps at June 30, 2014 and December 31, 2013 (in thousands):

	Gallons	Third Party Quotes(1)	Adjustments(2)	Total Amount
As of June 30, 2014				
Propane swaps	89,460	$ (5,008)	$ —	$ (5,008)
Isobutane swaps	2,520	(767)	313	(454)
Normal butane swaps	2,520	342	85	427
Natural gasoline swaps	21,168	539	(1,192)	(653)
Total NGL swaps – June 30, 2014	115,668	$ (4,894)	$ (794)	$ (5,688)
As of December 31, 2013				
Propane swaps	100,296	$ (10,260)	$ —	$ (10,260)
Isobutane swaps	6,300	(2,342)	955	(1,387)
Normal butane swaps	7,560	40	322	362
Natural gasoline swaps	16,002	132	(813)	(681)
Total NGL swaps – December 31, 2013	130,158	$ (12,430)	$ 464	$ (11,966)

(1) Based upon the difference between the quoted market price provided by the third party and the fixed price of the swap.
(2) Product and location basis differentials calculated through the use of a regression model, which compares the difference between the settlement prices for the products and locations quoted by the third party and the settlement prices for the actual products and locations underlying the derivatives, using a three year historical period.

The following table provides a summary of the regression coefficient utilized in the calculation of the unobservable inputs for the Level 3 fair value measurements for the NGL fixed price swaps for the periods indicated (in thousands):

	Level 3 NGL Swap Fair Value Adjustments	Adjustment based upon Regression Coefficient		
		Lower 95%	Upper 95%	Average
As of June 30, 2014:				
Isobutane	$ 313	1.1090	1.1194	1.1142
Normal butane	85	1.0292	1.0329	1.0311
Natural gasoline	(1,192)	0.9695	0.9726	0.9711
Total Level 3 adjustments – June 30, 2014	$ (794)			
As of December 31, 2013:				
Isobutane	$ 955	1.1184	1.1284	1.1234
Normal butane	322	1.0341	1.0386	1.0364
Natural gasoline	(813)	0.9727	0.9751	0.9739
Total Level 3 adjustments – December 31, 2013	$ 464			

NGL Linefill

The Partnership had $23.4 million and $14.5 million of NGL linefill at June 30, 2014 and December 31, 2013, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties, for which the counterparty will pay at a designated later period at a price determined by the then market price. The Partnership’s NGL linefill held by some counterparties will be settled at various periods in the future and is defined as a Level 3 asset, which is valued using the same forward price curve utilized to value the Partnership’s NGL fixed price swaps. The product/location adjustment based upon the multiple regression analysis, which was included in the value of the linefill, was a reduction of $0.4 million and $0.4 million as of June 30, 2014 and December 31, 2013, respectively. The Partnership’s NGL linefill held by other counterparties is adjusted on a monthly basis according to the volumes delivered to the counterparties each period and is valued on a first in first out (“FIFO”) basis.

The following table provides a summary of changes in fair value of the Partnership's NGL linefill for the six months ended June 30, 2014 (in thousands):

	Linefill Valued at Market		Linefill Valued on FIFO		Total NGL Linefill	
	Gallons	Amount	Gallons	Amount	Gallons	Amount
Balance – December 31, 2013	5,788	$ 4,738	11,538	$ 9,778	17,326	$ 14,516
Deliveries into NGL linefill	1,050	1,013	42,604	31,549	43,654	32,562
NGL linefill sales	—	—	(34,557)	(23,725)	(34,557)	(23,725)
Net change in NGL linefill valuation(1)	—	94	—	—	—	94
Balance – June 30, 2014	6,838	$ 5,845	19,585	$ 17,602	26,423	$ 23,447

(1) Included within natural gas and liquids sales on the Partnership's consolidated statements of operations.

Contingent Consideration

In February 2012, the Partnership acquired a gas gathering system and related assets for an initial net purchase price of $19.0 million. The Partnership agreed to pay up to an additional $12.0 million in contingent payments, payable in two equal amounts, if certain volumes are achieved on the acquired gathering system within a specified time period. Sufficient volumes were achieved in December 2012 and the Partnership paid the first contingent payment of $6.0 million in January 2013. As of June 30, 2014, the fair value of the remaining contingent payment resulted in a $6.0 million long term liability, which was recorded within other long term liabilities on the Partnership's consolidated balance sheets. The range of the undiscounted amount the Partnership could pay related to the remaining contingent payment is between $0.0 and $6.0 million.

Other Financial Instruments

The estimated fair value of the Partnership's other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership's current assets and liabilities on its consolidated balance sheets, other than the derivatives, NGL linefill and contingent consideration discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1 values. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value and thus is categorized as a Level 1 value. The estimated fair value of the Partnership's Senior Notes (see Note 13) is based upon the market approach and calculated using the yield of the Senior Notes as provided by financial institutions and thus is categorized as a Level 3 value. The estimated fair values of the Partnership's total debt at June 30, 2014 and December 31, 2013, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were $1,685.3 million and $1,663.6 million, respectively, compared with the carrying amounts of $1,654.6 million and $1,707.3 million, respectively.

Acquisitions

On May 7, 2013, the Partnership completed the TEAK Acquisition (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. These inputs require significant judgments and estimates at the time of the valuation.

NOTE 12 – ACCRUED LIABILITIES

The following is a summary of accrued liabilities (in thousands):

	June 30, 2014	December 31, 2013
Accrued capital expenditures	$12,217	$ 17,898
Acquisition-related liabilities	6,712	8,933
Accrued ad valorem and production taxes	13,619	3,551
Other	20,262	17,067
	$52,810	$ 47,449

NOTE 13 – DEBT

Total debt consists of the following (in thousands):

	June 30, 2014	December 31, 2013
Revolving credit facility	$ 100,000	$ 152,000
6.625% Senior notes – due 2020	504,219	504,556
5.875% Senior notes – due 2023	650,000	650,000
4.750% Senior notes – due 2021	400,000	400,000
Capital lease obligations	420	754
Total debt	1,654,639	1,707,310
Less current maturities	(320)	(524)
Total long term debt	$1,654,319	$1,706,786

Cash payments for interest related to debt, net of capitalized interest, were $8.2 million and $0.4 million for the three months ended June 30, 2014 and 2013, respectively, and $43.0 million and $22.5 million for the six months ended June 30, 2014 and 2013.

Revolving Credit Facility

At June 30, 2014, the Partnership had a $600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. The weighted average interest rate for borrowings on the revolving credit facility, at June 30, 2014, was 3.2%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $3.1 million was outstanding at June 30, 2014. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At June 30, 2014, the Partnership had $496.9 million of remaining committed capacity under its revolving credit facility.

The events that constitute an event of default for the revolving credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the General Partner.

On March 11, 2014, the Partnership entered into an amendment to the credit agreement governing the revolving credit facility which, among other changes:

- adjusted the duration of, and maximum ratios allowed during, the Acquisition Period, as defined in the credit agreement, for the Consolidated Funded Debt Ratio, as defined in the credit agreement; and
- permitted the payment of cash distributions, if any, on the Class E Preferred Units so long as the Partnership has a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to $50 million.

As of June 30, 2014, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At June 30, 2014, the Partnership had $500.0 million principal outstanding of 6.625% unsecured senior notes due October 1, 2020 ("6.625% Senior Notes"), $650.0 million principal outstanding of 5.875% unsecured senior notes due August 1, 2023 ("5.875% Senior Notes"), and $400.0 million of 4.75% unsecured senior notes due November 15, 2021 ("4.75% Senior Notes" and with the 6.625% Senior Notes and 5.875% Senior Notes, the "Senior Notes"). The 6.625% Senior Notes are presented combined with a net $4.2 million unamortized premium as of June 30, 2014.

Indentures governing the Senior Notes contain covenants, including limitations of the Partnership's ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all its assets. The Partnership is in compliance with these covenants as of June 30, 2014.

4.75% Senior Notes

On May 10, 2013, the Partnership issued $400.0 million of the 4.75% Senior Notes in a private placement transaction. The 4.75% Senior Notes were issued at par. The Partnership received net proceeds of $391.2 million after underwriting commissions and other transactions costs and utilized the proceeds to repay a portion of the outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition (see Note 3).

5.875% Senior Notes

On February 11, 2013, the Partnership issued $650.0 million of the 5.875% Senior Notes in a private placement transaction. The 5.875% Senior Notes were issued at par. The Partnership received net proceeds of $637.3 million after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the credit facility.

8.75% Senior Notes

On January 28, 2013, the Partnership commenced a cash tender offer for any and all of its outstanding 8.75% Senior Notes and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default contained in the indenture governing the 8.75% Senior

Notes ("8.75% Senior Notes Indenture"). Approximately $268.4 million aggregate principal amount of the 8.75% Senior Notes were validly tendered as of the expiration date of the consent solicitation. In February 2013, the Partnership accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and paid $291.4 million to redeem the $268.4 million principal plus $11.2 million make-whole premium, $3.7 million accrued interest and $8.0 million consent payment. The Partnership entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture.

On March 12, 2013, the Partnership paid $105.6 million to redeem the remaining $97.3 million 8.75% Senior Notes not purchased in connection with the tender offer, plus a $6.3 million make-whole premium and $2.0 million in accrued interest. The Partnership funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

Capital Leases

The following is a summary of the leased property under capital leases as of June 30, 2014 and December 31, 2013, which are included within property, plant and equipment (see Note 6) (in thousands):

	June 30, 2014	December 31, 2013
Pipelines, processing and compression facilities	$1,142	$ 2,281
Less – accumulated depreciation	(175)	(330)
	$ 967	$ 1,951

During the six months ended June 30, 2014, the Partnership took ownership of $1.1 million of facilities in connection with the conclusion of a capital lease. Depreciation expense for leased properties was $32 thousand and $39 thousand for the three months ended June 30, 2014 and 2013, respectively, and $64 thousand and $250 thousand for the six months ended June 30, 2014 and 2013, respectively, which is included within depreciation and amortization expense on the Partnership's consolidated statements of operations (see Note 6).

NOTE 14 – COMMITMENTS AND CONTINGENCIES

The Partnership has certain long-term unconditional purchase obligations and commitments, consisting primarily of transportation contracts. These agreements provide for transportation services to be used in the ordinary course of the Partnership's operations. Transportation fees paid related to these contracts, including minimum shipment payments, were $7.9 million and $3.1 million for the three months ended June 30, 2014 and 2013, respectively, and $15.2 million and $6.1 million for the six months ended June 30, 2014 and 2013, respectively. The future fixed and determinable portion of the obligations as of June 30, 2014 was as follows: remainder of 2014 – $3.0 million; 2015 – $3.4 million; 2016 to 2017 – $3.5 million per year; and 2018 – $2.7 million.

The Partnership had committed approximately $182.4 million for the purchase of property, plant and equipment at June 30, 2014.

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on its financial condition or results of operations.

NOTE 15 – BENEFIT PLANS

Long-Term Incentive Plans

The Partnership has a 2004 Long-Term Incentive Plan ("2004 LTIP") and a 2010 Long-Term Incentive Plan ("2010 LTIP" and collectively with the 2004 LTIP, the "LTIPs") in which officers, employees, non-employee managing board members of the General Partner, employees of the General Partner's affiliates and consultants are eligible to participate. The LTIPs are administered by the compensation committee appointed by the General Partner's managing board (the "Compensation Committee"). Under the LTIPs, the Compensation Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At June 30, 2014, the Partnership had 2,046,819 phantom units outstanding under the Partnership's LTIPs, with 121,946 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options that have vested and have been exercised.

Partnership Phantom Units

Phantom units granted to employees under the LTIPs generally have vesting periods of four years. However, in February 2014, the Partnership granted 227,000 phantom units with a vesting period of three years. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards to non-employee members of the board automatically vest upon a change of control, as defined in the LTIPs. At June 30, 2014, there were 621,295 phantom units outstanding under the LTIPs that will vest within twelve months.

All phantom units outstanding under the LTIPs at June 30, 2014 include distribution equivalent rights ("DERs"), which are rights to receive cash per phantom unit in an amount equal to and at the same time as the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. The DERs were granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were $1.0 million and $0.6 million during the three months ended June 30, 2014 and 2013, respectively, and $1.9 million and $1.2 million during the six months ended June 30, 2014 and 2013, respectively. These amounts were recorded as reductions of equity on the Partnership's consolidated balance sheets.

The following table sets forth the Partnership's LTIPs phantom unit activity for the periods indicated:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	1,664,642	$35.59	1,057,083	$33.22	1,446,553	$ 36.32	1,053,242	$33.21
Granted	487,873	33.92	36,971	38.10	722,574	32.98	43,775	37.32
Forfeited	(1,450)	36.34	(2,100)	32.95	(3,650)	38.25	(2,100)	32.95
Matured and issued(2)(3)	(104,246)	30.49	(182,942)	32.65	(118,658)	30.92	(185,905)	32.59
Outstanding, end of period(4)	2,046,819	$35.45	909,012	$33.54	2,046,819	$ 35.45	909,012	$33.54
Matured and not issued(5)	112,423	$32.19	39,347	$24.91	112,423	$ 32.19	39,347	$24.91
Non-cash compensation expense recognized (in thousands)		$6,443		$3,436		$12,882		$7,820

(1) Fair value based upon weighted average grant date price.
(2) The intrinsic values for phantom unit awards exercised during the three months ended June 30, 2014 and 2013 were $3.3 million and $6.6 million, respectively, and $3.8 million and $6.7 million during the six months ended June 30, 2014 and 2013, respectively.
(3) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2014 and December 31, 2013 was $70.4 million and $50.7 million, respectively.
(4) There were 26,042 and 22,539 outstanding phantom unit awards at June 30, 2014 and December 31, 2013, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.
(5) The aggregate intrinsic value for phantom unit awards vested but not issued at June 30, 2014 and 2013 was $3.6 million and $1.5 million, respectively.

At June 30, 2014, the Partnership had approximately $41.6 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.1 years.

NOTE 16 – RELATED PARTY TRANSACTIONS

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of ATLS. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to its employees who perform services for the Partnership based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by ATLS based on the number of its employees who devote their time to activities on the Partnership's behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $1.3 million in each of the three month periods ended June 30, 2014 and 2013, and $2.5 million in each of the six month periods ended June 30, 2014 and 2013, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the six months ended June 30, 2014 and 2013. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

The Partnership compresses and gathers gas for Atlas Resource Partners, L.P. (NYSE: ARP) (“ARP”) on its gathering systems located in Tennessee. ARP’s general partner is wholly-owned by ATLS, and two members of the General Partner’s managing board are members of ARP’s board of directors. The Partnership entered into an agreement to provide these services, which extends for the life of ARP’s leases, in February 2008. The Partnership charged ARP approximately $0.1 million and $0.1 million in compression and gathering fees for the three months ended June 30, 2014 and 2013, respectively, and $0.1 million and $0.1 million in compression and gathering fees for the six months ended June 30, 2014 and 2013, respectively.

NOTE 17 – SEGMENT INFORMATION

As a result of the sale of the Partnership’s subsidiaries owning an interest in WTLPG on May 14, 2014 (see Note 4), the Partnership assessed its reportable segments and realigned its reportable segments into two new segments: Oklahoma Gathering and Processing (“Oklahoma”) and Texas Gathering and Processing (“Texas”). These reportable segments reflect the way the Partnership will manage its operations going forward. The Partnership has adjusted its segment presentation from the amounts previously presented to reflect the realignment of the segments.

The Oklahoma segment consists of the SouthOK and WestOK operations, which are comprised of natural gas gathering, processing and treating assets servicing drilling activity in the Anadarko and Arkoma Basins and which were formerly included within the previous Gathering and Processing segment. Oklahoma revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas within the state of Oklahoma.

The Texas segment consists of (1) the SouthTX and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Permian Basin and the Eagle Ford Shale play in south Texas; and (2) the natural gas gathering assets located in the Barnett Shale play in Texas. These assets were formerly included within the previous Gathering and Processing segment. Texas revenues are primarily derived from the sale of residue gas and NGLs and the gathering and processing of natural gas within the state of Texas.

The previous Transportation and Treating segment, which consisted of (1) the gas treating operations, which own contract gas treating facilities located in various shale plays; and (2) the former subsidiaries’ interest in WTLPG, has been eliminated and the financial information is now included within Corporate and Other. The natural gas gathering assets located in the Appalachian Basin in Tennessee, which were formerly included in the previous Gathering and Processing Segment, are now included within Corporate and Other.

The following summarizes the Partnership's reportable segment data for the periods indicated (in thousands):

	Oklahoma	Texas	Corporate and Other	Consolidated
Three Months Ended June 30, 2014:				
Revenue:				
Revenues – third party(1)	$435,346	$283,221	$ (4,702)	$ 713,865
Revenues – affiliates	—	—	91	91
Total revenues	435,346	283,221	(4,611)	713,956
Costs and Expenses:				
Natural gas and liquids cost of sales	345,711	235,174	—	580,885
Operating expenses	14,910	11,561	512	26,983
General and administrative(1)	—	—	18,416	18,416
Other (revenues) costs	—	—	(20)	(20)
Depreciation and amortization	26,118	21,948	1,154	49,220
Interest expense(1)	—	—	23,059	23,059
Total costs and expenses	386,739	268,683	43,121	698,543
Equity income (loss) in joint ventures	—	(4,760)	885	(3,875)
Gain on asset disposition	—	—	48,465	48,465
Income before tax	48,607	9,778	1,618	60,003
Income tax benefit	(498)	—	—	(498)
Net income	$ 49,105	$ 9,778	$ 1,618	$ 60,501

	Oklahoma	Texas	Corporate and Other	Consolidated
Three Months Ended June 30, 2013:				
Revenue:				
Revenues – third party(1)	$360,600	$171,721	$ 28,541	$ 560,862
Revenues – affiliates	—	—	77	77
Total revenues	360,600	171,721	28,618	560,939
Costs and Expenses:				
Natural gas and liquids cost of sales	283,458	140,758	—	424,216
Operating expenses	16,532	7,765	473	24,770
General and administrative(1)	—	—	12,546	12,546
Other costs	—	—	18,370	18,370
Depreciation and amortization	30,055	13,795	2,533	46,383
Interest expense(1)	—	—	22,581	22,581
Total costs and expenses	330,045	162,318	56,503	548,866
Equity income in joint ventures	—	(2,159)	1,687	(472)
Loss on asset disposition	(1,519)	—	—	(1,519)
Loss on early extinguishment of debt	—	—	(19)	(19)
Income (loss) before tax	29,036	7,244	(26,217)	10,063
Income tax benefit	(28)	—	—	(28)
Net income (loss)	$ 29,064	$ 7,244	$(26,217)	$ 10,091

	Oklahoma	Texas	Corporate and Other	Consolidated
Six Months Ended June 30, 2014:				
Revenue:				
Revenues – third party(1)	$866,370	$559,780	$(12,336)	$1,413,814
Revenues – affiliates	—	—	146	146
Total revenues	866,370	559,780	(12,190)	1,413,960
Costs and Expenses:				
Natural gas and liquids cost of sales	692,355	463,998	—	1,156,353
Operating expenses	29,143	21,914	1,054	52,111
General and administrative(1)	—	—	36,356	36,356
Other costs	—	—	17	17
Depreciation and amortization	51,651	44,495	2,313	98,459
Interest expense(1)	—	—	46,722	46,722
Total costs and expenses	773,149	530,407	86,462	1,390,018
Equity income (loss) in joint ventures	—	(8,365)	2,612	(5,753)
Gain on asset disposition	—	—	48,465	48,465
Income (loss) before tax	93,221	21,008	(47,575)	66,654
Income tax benefit	(896)	—	—	(896)
Net income (loss)	$ 94,117	$ 21,008	$(47,575)	$ 67,550

	Oklahoma	Texas	Corporate and Other	Consolidated
Six Months Ended June 30, 2013:				
Revenue:				
Revenues – third party(1)	$657,630	$293,129	$ 17,944	$ 968,703
Revenues – affiliates	—	—	148	148
Total revenues	657,630	293,129	18,092	968,851
Costs and Expenses:				
Natural gas and liquids cost of sales	509,900	239,856	—	749,756
Operating expenses	31,988	13,684	957	46,629
General and administrative(1)	—	—	26,344	26,344
Other costs	—	—	18,900	18,900
Depreciation and amortization	51,502	22,171	3,168	76,841
Interest expense(1)	—	—	41,267	41,267
Total costs and expenses	593,390	275,711	90,636	959,737
Equity income in joint ventures	—	(2,159)	3,727	1,568
Loss on asset disposition	(1,519)	—	—	(1,519)
Loss on early extinguishment of debt	—	—	(26,601)	(26,601)
Income (loss) before tax	62,721	15,259	(95,418)	(17,438)
Income tax benefit	(37)	—	—	(37)
Net income (loss)	$ 62,758	$ 15,259	$(95,418)	$ (17,401)

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to the reportable segments as it would be unfeasible to reasonably do so.

Capital Expenditures:	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Oklahoma	$ 77,764	$ 55,352	$126,552	$118,804
Texas	74,185	50,620	153,312	94,772
Corporate and other	299	1,221	715	2,133
	$152,248	$107,193	$280,579	$215,709

Balance Sheet	June 30, 2014	December 31, 2013
Equity method investment in joint ventures:		
Texas	$ 179,054	$ 162,511
Corporate and other	—	85,790
	$ 179,054	$ 248,301
Goodwill:		
Oklahoma	$ 178,762	$ 178,762
Texas	187,001	189,810
	$ 365,763	$ 368,572
Total assets:		
Oklahoma	$2,397,683	$2,265,231
Texas	1,995,467	1,872,165
Corporate and other	99,879	190,449
	$4,493,029	$4,327,845

The following table summarizes the Partnership's natural gas and liquids sales by product or service for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Natural gas and liquids sales:				
Natural gas	$285,197	$191,885	$ 556,249	$333,369
NGLs	341,695	270,240	702,449	488,071
Condensate	40,707	30,444	71,888	55,009
Other	(50)	(1,339)	93	(1,371)
Total	$667,549	$491,230	$1,330,679	$875,078

NOTE 18 – SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership's Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership's consolidated financial statements as of June 30, 2014 and December 31, 2013 and for the three and six months ended June 30, 2014 and 2013 include the financial statements of Atlas Pipeline Mid-Continent WestOK, LLC ("WestOK, LLC"), Atlas Pipeline Mid-Continent WestTex, LLC ("WestTex, LLC") and Centrahoma Processing, LLC ("Centrahoma"), as well as the equity interest of two of the Partnership's subsidiaries in WTLPG, prior to the sale on May 14, 2014 (see Note 4), and the equity interests in the T2 Joint Ventures. Under the terms of the Senior Notes and the revolving credit facility, WestOK, LLC, WestTex, LLC, Centrahoma and the T2 Joint Ventures are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership's stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership's consolidated accounts as of June 30, 2014 and December 31, 2013 and for the three and six months ended June 30, 2014 and 2013. For the purpose of the following financial information, the Partnership's investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented in accordance with the equity method of accounting (in thousands):

Balance Sheets June 30, 2014	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$ —	$ 170	$ 3,904	$ —	$ 4,074
Accounts receivable – affiliates	—	210,759	—	(210,759)	—
Other current assets	134	46,553	235,765	(950)	281,502
Total current assets	134	257,482	239,669	(211,709)	285,576
Property, plant and equipment, net	—	848,833	2,135,335	—	2,984,168
Intangible assets, net	—	554,237	79,849	—	634,086
Goodwill	—	320,869	44,894	—	365,763
Equity method investment in joint ventures	—	—	179,054	—	179,054
Long term portion of derivative assets	—	451	—	—	451
Long term notes receivable	—	—	1,852,928	(1,852,928)	—
Equity investments	4,122,015	970,042	—	(5,092,057)	—
Other assets, net	37,714	1,787	4,430	—	43,931
Total assets	$4,159,863	$2,953,701	$4,536,159	$(7,156,694)	$4,493,029
Liabilities and Equity					
Accounts payable – affiliates	$ 78,741	$ —	$ 136,320	$ (210,759)	$ 4,302
Other current liabilities	27,201	97,761	270,285	—	395,247
Total current liabilities	105,942	97,761	406,605	(210,759)	399,549
Long-term portion of derivative liabilities	—	216	—	—	216
Long-term debt, less current portion	1,654,219	100	—	—	1,654,319
Deferred income taxes, net	—	32,394	—	—	32,394
Other long-term liabilities	162	849	6,000	—	7,011
Equity	2,399,540	2,822,381	4,123,554	(6,945,935)	2,399,540
Total liabilities and equity	$4,159,863	$2,953,701	$4,536,159	$(7,156,694)	$4,493,029

December 31, 2013	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$ —	$ 168	$ 4,746	$ —	$ 4,914
Accounts receivable – affiliates	765,236	—	—	(765,236)	—
Other current assets	215	52,910	185,975	(2,236)	236,864
Total current assets	765,451	53,078	190,721	(767,472)	241,778
Property, plant and equipment, net	—	723,302	2,000,890	—	2,724,192
Intangible assets, net	—	603,533	92,738	—	696,271
Goodwill	—	323,678	44,894	—	368,572
Equity method investment in joint venture	—	—	248,301	—	248,301
Long term portion of derivative assets	—	2,270	—	—	2,270
Long term notes receivable	—	—	1,852,928	(1,852,928)	—
Equity investments	3,186,938	1,487,358	—	(4,674,296)	—
Other assets, net	41,094	1,787	3,580	—	46,461
Total assets	$3,993,483	$3,195,006	$4,434,052	$(7,294,696)	$4,327,845
Liabilities and Equity					
Accounts payable – affiliates	$ —	$ 423,078	$ 345,070	$ (765,236)	$ 2,912
Other current liabilities	26,819	75,031	215,464	—	317,314
Total current liabilities	26,819	498,109	560,534	(765,236)	320,226
Long-term portion of derivative liabilities	—	320	—	—	320
Long-term debt, less current portion	1,706,556	230	—	—	1,706,786
Deferred income taxes, net	—	33,290	—	—	33,290
Other long-term liabilities	203	1,115	6,000	—	7,318
Equity	2,259,905	2,661,942	3,867,518	(6,529,460)	2,259,905
Total liabilities and equity	$3,993,483	$3,195,006	$4,434,052	$(7,294,696)	$4,327,845

Statements of Operations	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended June 30, 2014					
Total revenues	$ —	$ 129,504	$ 588,248	$ (3,796)	$ 713,956
Total costs and expenses	(23,215)	(153,351)	(525,773)	3,796	(698,543)
Equity income (loss)	79,751	54,635	(3,875)	(134,386)	(3,875)
Gain on asset disposition	—	48,465	—	—	48,465
Income (loss), before tax	56,536	79,253	58,600	(134,386)	60,003
Income tax benefit	—	(498)	—	—	(498)
Net income (loss)	56,536	79,751	58,600	(134,386)	60,501
Income attributable to non-controlling interest	—	—	(3,965)	—	(3,965)
Preferred unit imputed dividend effect	(11,378)	—	—	—	(11,378)
Preferred unit dividends in kind	(10,406)	—	—	—	(10,406)
Preferred unit dividends	(2,609)	—	—	—	(2,609)
Net income (loss) attributable to common limited partners and the General Partner	$ 32,143	$ 79,751	$ 54,635	$ (134,386)	$ 32,143
Three Months Ended June 30, 2013					
Total revenues	$ —	$ 158,014	$ 425,516	$ (22,591)	$ 560,939
Total costs and expenses	(21,332)	(164,950)	(384,580)	21,996	(548,866)
Equity income (loss)	29,635	38,654	—	(68,761)	(472)
Loss on early extinguishment of debt	(19)	—	—	—	(19)
Loss on asset disposition	—	(1,519)	—	—	(1,519)
Income (loss), before tax	8,284	30,199	40,936	(69,356)	10,063
Income tax benefit	—	(28)	—	—	(28)
Net income (loss)	8,284	30,227	40,936	(69,356)	10,091
Income attributable to non-controlling interest	—	—	(1,810)	—	(1,810)
Preferred unit imputed dividend effect	—	(6,729)	—	—	(6,729)
Preferred unit dividends in kind	—	(5,341)	—	—	(5,341)
Preferred unit dividends	—	—	—	—	—
Net income (loss) attributable to common limited partners and the General Partner	$ 8,284	$ 18,157	$ 39,126	$ (69,356)	$ (3,789)

Statements of Operations	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Six Months Ended June 30, 2014					
Total revenues	$ —	$ 276,340	$ 1,144,786	$ (7,166)	$ 1,413,960
Total costs and expenses	(47,020)	(325,215)	(1,024,949)	7,166	(1,390,018)
Equity income (loss)	108,143	107,657	(5,753)	(215,800)	(5,753)
Gain on asset disposition	—	48,465	—	—	48,465
Income (loss), before tax	61,123	107,247	114,084	(215,800)	66,654
Income tax benefit	—	(896)	—	—	(896)
Net income (loss)	61,123	108,143	114,084	(215,800)	67,550
Income attributable to non-controlling interest	—	—	(6,427)	—	(6,427)
Preferred unit imputed dividend effect	(22,756)	—	—	—	(22,756)
Preferred unit dividends in kind	(20,125)	—	—	—	(20,125)
Preferred unit dividends	(3,015)	—	—	—	(3,015)
Net income (loss) attributable to common limited partners and the General Partner	$ 15,227	$ 108,143	$ 107,657	$ (215,800)	$ 15,227
Six Months Ended June 30, 2013					
Total revenues	$ —	$ 249,856	$ 760,887	$ (41,892)	$ 968,851
Total costs and expenses	(39,929)	(279,176)	(681,929)	41,297	(959,737)
Equity income (loss)	45,951	77,348	—	(121,731)	1,568
Loss on early extinguishment of debt	(26,601)	—	—	—	(26,601)
Loss on asset disposition	—	(1,519)	—	—	(1,519)
Income (loss), before tax	(20,579)	46,509	78,958	(122,326)	(17,438)
Income tax benefit	—	(37)	—	—	(37)
Net income (loss)	(20,579)	46,546	78,958	(122,326)	(17,401)
Income attributable to non-controlling interest	—	—	(3,179)	—	(3,179)
Preferred unit imputed dividend effect	—	(6,729)	—	—	(6,729)
Preferred unit dividends in kind	—	(5,341)	—	—	(5,341)
Preferred unit dividends	—	—	—	—	—
Net income (loss) attributable to common limited partners and the General Partner	$ (20,579)	$ 34,476	$ 75,779	$ (122,326)	$ (32,650)

Statements of Cash Flows	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Six Months Ended June 30, 2014					
Net cash provided by (used in):					
Operating activities	$ 311,927	$ 108,955	$ 171,974	$ (452,947)	$ 139,909
Investing activities	(321,923)	(140,298)	(105,953)	417,762	(150,412)
Financing activities	9,996	31,345	(66,863)	35,185	9,663
Net change in cash and cash equivalents	—	2	(842)	—	(840)
Cash and cash equivalents, beginning of period	—	168	4,746	—	4,914
Cash and cash equivalents, end of period	$ —	$ 170	$ 3,904	$ —	$ 4,074
Six Months Ended June 30, 2013					
Net cash provided by (used in):					
Operating activities	$ (371,569)	$ 69,916	$ 92,738	$ 280,636	$ 71,721
Investing activities	(807,215)	(978,215)	(213,535)	782,721	(1,216,244)
Financing activities	1,178,784	947,617	99,162	(1,063,357)	1,162,206
Net change in cash and cash equivalents	—	39,318	(21,635)	—	17,683
Cash and cash equivalents, beginning of period	—	157	3,241	—	3,398
Cash and cash equivalents, end of period	$ —	$ 39,475	$ (18,394)	$ —	$ 21,081

NOTE 19 – SUBSEQUENT EVENTS

On July 23, 2014, the Partnership declared a cash distribution of $0.63 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2014. The $58.8 million distribution, including $7.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2014 to unitholders of record at the close of business on August 7, 2014 (see Note 5). Based on this declaration, the Partnership will also issue approximately 305,000 additional Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution in kind for the quarter ended June 30, 2014.

On July 15, 2014, the Partnership paid a cash distribution of $0.67604 per unit, or approximately $3.4 million, on its Class E Preferred Units, representing the cash distribution for the period March 17, 2014 to July 14, 2014.

Targa Resources Partners LP
Unaudited Pro Forma Condensed Consolidated Financial Statements

Acquisition of Atlas Pipeline Partners, L.P.

On October 13, 2014, Targa Resources Partners LP (the "Partnership", "TRP", "we", "us", or "our") and Targa Resources Corp. ("TRC") entered into an Agreement and Plan of Merger (the "MLP Merger Agreement") by and among the Partnership, TRC, Targa Resources GP LLC, a Delaware limited liability company and the general partner of the Partnership (the "GP"), Trident MLP Merger Sub LLC, a Delaware limited liability company and a newly formed, wholly owned subsidiary of the Partnership ("MLP Merger Sub"), Atlas Energy, L.P., a Delaware limited partnership ("ATLS"), Atlas Pipeline Partners, L.P, a Delaware limited partnership ("APL") and Atlas Pipeline Partners GP LLC, a Delaware limited liability company and the general partner of APL. Under the terms and conditions set forth in the MLP Merger Agreement (the "APL Merger"), MLP Merger Sub will be merged with and into APL, with APL continuing as the surviving entity and as a wholly owned subsidiary of the Partnership.

The Partnership will acquire APL (the "APL acquisition") for total consideration of $5.8 billion, including $1.8 billion of debt as of September 30, 2014. Each APL common unitholder will be entitled to receive 0.5846 units of the Partnership (the "APL Unit Consideration") and a one-time cash payment of $1.26 per APL common unit (the "APL Cash Consideration") for total consideration of $38.66 per APL common unit, based on the closing price of the Partnership's units on October 10, 2014. The exchange ratio was negotiated as a 15% premium for APL common unitholders based on the volume weighted average prices of APL and TRP units during the 15 trading days ending October 3, 2014. APL has agreed to exercise its right under the certificate of designations of the APL Class D Preferred Units, to convert all APL Class D Preferred Units that are issued and outstanding as of the record date for the APL unitholders meeting (which will be held to vote on the APL Merger) into APL common units.

APL has agreed to exercise its right under the certificate of designations of the APL Class E Preferred Units to redeem the APL Class E Preferred Units for $126.5 million immediately prior to the effective time of the APL Merger, and the Partnership has agreed to deposit the funds for such redemption with the paying agent. The Partnership expects to finance the cash portion of the transaction with borrowings under its revolving credit facility. In connection with the acquisitions, TRC has agreed to reduce its incentive distribution rights for the four years following closing by fixed amounts of $37.5 million, $25.0 million, $10.0 million and $5.0 million, respectively. These annual amounts will be applied in equal quarterly installments for each successive four quarter period following closing.

In connection with the APL Merger, each outstanding APL phantom unit award held by an employee of APL will be cancelled and converted into the right to receive (1) the APL Cash Consideration in respect of each APL common unit underlying such APL phantom unit award and (2) a TRP phantom unit award with respect to a number of TRP common units equal to the product of the APL Unit Consideration multiplied by the number of APL common units underlying such APL phantom unit award. Following the closing of the APL Merger, the TRP phantom unit award will continue to have the same material terms and conditions and the same vesting conditions as applied to the corresponding APL phantom unit award immediately prior to the closing of the APL Merger, and will settle in TRP common units upon vesting.

The unaudited pro forma condensed consolidated financial information has been developed by applying pro forma adjustments to the historical audited and unaudited consolidated financial statements of the Partnership. The unaudited pro forma condensed consolidated balance sheet as of June 30, 2014 of the Partnership has been prepared to give effect to the APL acquisition as if it had occurred on June 30, 2014. The unaudited pro forma condensed consolidated statements of operations of the Partnership for the six months ended June 30, 2014 and year ended December 31, 2013, have been prepared to give effect to the APL acquisition as if it had occurred on January 1, 2013.

The unaudited pro forma condensed consolidated financial statements include pro forma adjustments that are factually supportable and directly attributable to the APL acquisition. In addition, with respect to the unaudited pro forma condensed consolidated statements of operation, pro forma adjustments have been made only for items that are expected to have a continuing impact on the consolidated results.

The unaudited pro forma condensed consolidated financial statements should be read in conjunction with (i) the historical audited consolidated financial statements and related notes included in the respective Annual Reports on Form 10-K for the year ended December 31, 2013 for the Partnership (as revised for the effects of the revenues and purchases adjustments described in the Partnership's Current Report on Form 8-K filed on October 23, 2014) and APL; (ii) the unaudited consolidated financial statements and related notes included in the respective Quarterly Reports on Form 10-Q for the six months ended June 30, 2014 for the Partnership (as revised for the effects of the revenues and purchases adjustments described in the Partnership's Current Report on Form 8-K filed on October 23, 2014) and APL; and (iii) the notes accompanying these unaudited pro forma condensed consolidated financial statements.

The unaudited pro forma adjustments are based on available preliminary information and certain assumptions that the Partnership believes are reasonable under the circumstances. The unaudited pro forma condensed consolidated financial statements are presented for informational purposes only and are not necessarily indicative of the results that might have occurred had the APL acquisition taken place on June 30, 2014 for balance sheet purposes, and on January 1, 2013 for statements of operations purposes, and are not intended to be a projection of future results. Actual results may vary significantly from the results reflected because of various factors. All pro forma adjustments and their underlying assumptions are described more fully in the notes to the unaudited pro forma condensed consolidated financial statements.

TARGA RESOURCES PARTNERS LP
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
JUNE 30, 2014

	Targa Resources Partners LP	Atlas Pipeline Partners, L.P.	Pro Forma Adjustments	Targa Resources Partners LP Pro Forma
		(In millions)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 67.3	$ 4.1	$ 304.7 (c)	$ 71.4
			(304.7)(c)	
			74.5 (d)	
			(74.5)(d)	
Trade receivables, net	682.2	254.9	—	937.1
Other current assets	159.2	26.5	—	185.7
Total current assets	908.7	285.5	—	1,194.2
Property, plant and equipment	6,158.8	3,444.1	(459.9)(a)	9,143.0
Accumulated depreciation	(1,539.4)	(459.9)	459.9 (a)	(1,539.4)
Property, plant and equipment, net	4,619.4	2,984.2	—	7,603.6
Goodwill	—	365.8	(365.8)(g)	—
Other intangible assets, net	622.7	634.1	2,022.0 (a)	3,278.8
Investment in unconsolidated affiliate	52.3	179.0	—	231.3
Other long-term assets	36.9	44.4	(37.7)(a)	43.6
Total assets	$ 6,240.0	$ 4,493.0	$ 1,618.5	$ 12,351.5
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities	$ 825.2	$ 399.3	$ 36.4 (f)	$ 1,260.9
Current portion of long-term debt	—	0.3	—	0.3
Total current liabilities	825.2	399.6	36.4	1,261.2
Long-term debt	2,961.2	1,654.3	30.7 (a)	4,850.9
			(74.5)(c)	
			100.0 (c)	
			(100.0)(c)	
			279.2 (c)	
Deferred income taxes	13.4	32.4	—	45.8
Other long-term liabilities	59.4	7.2	—	66.6
Commitments and contingencies				
Owners' equity:				
Class D convertible preferred limited partners' interests	—	493.6	(493.6)(b)	—
Class E preferred limited partners' interests	—	121.9	(121.9)(b)	—
Common unit holders	2,158.8	1,666.4	493.6 (b)	5,759.4
			(2,160.0)(e)	
			3,636.3 (e)	
			(35.7)(f)	
General partner	69.1	45.8	74.5 (d)	142.9
			(45.8)(d)	
			(0.7)(f)	
Accumulated other comprehensive income (loss)	(11.5)	—	—	(11.5)
	2,216.4	2,327.7	1,346.7	5,890.8
Noncontrolling interests in subsidiaries	164.4	71.8	—	236.2
Total owners' equity	2,380.8	2,399.5	1,346.7	6,127.0
Total liabilities and owners' equity	$ 6,240.0	$ 4,493.0	$ 1,618.5	$ 12,351.5

See accompanying notes to unaudited pro forma condensed consolidated financial statements

TARGA RESOURCES PARTNERS LP
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2014

	Targa Resources Partners LP	Atlas Pipeline Partners, L.P.	Pro Forma Adjustments	Targa Resources Partners LP Pro Forma
		(In millions)		
Revenues	$ 4,295.3	$ 1,414.0	$ (0.0)(h)	$ 5,709.3
Costs and expenses:				
Product purchases	3,531.7	1,156.3	(0.0)(h)	4,688.0
Operating expenses	210.9	52.1	—	263.0
Depreciation and amortization expense	165.3	98.5	(6.6)(i)	323.6
			66.4 (j)	
General and administrative expense	74.8	36.4	(2.5)(k)	104.3
			(4.4) (l)	
Other operating (income) expense	(1.0)	(48.5)	48.5 (m)	(1.0)
Income from operations	313.6	119.2	(101.4)	331.4
Other income (expense):				
Interest expense, net	(68.1)	(46.7)	3.9 (n)	(110.9)
Equity earnings (loss)	9.1	(5.8)	(2.6)(m)	0.7
Income before income taxes	254.6	66.7	(100.1)	221.2
Income tax (expense) benefit:	(2.4)	0.9	—	(1.5)
Net income	252.2	67.6	(100.1)	219.7
Less: Net income attributable to noncontrolling interests	21.0	6.4	—	27.4
Preferred unit dividend effect	—	22.8	(22.8)(b)	—
Preferred unit dividends in kind	—	20.2	(20.2)(b)	—
Preferred unit dividends	—	3.0	(3.0)(b)	—
Net income attributable to limited partners and general partner	$ 231.2	$ 15.2	$ (54.1)	$ 192.3
Net income attributable to general partner	$ 69.6		$ (13.2)(o)	$ 56.4
Net income attributable to limited partners	161.6		(25.7)(o)	135.9
Net income attributable to Targa Resources Partners LP	$ 231.2		$ (38.9)	$ 192.3
Net income per limited partner unit - basic	$ 1.43			$ 0.81
Net income per limited partner unit - diluted	$ 1.42			$ 0.80
Weighted average limited partner units outstanding - basic	113.3	80.8	(25.3)(p)	168.8
Weighted average limited partner units outstanding - diluted	113.9	96.5	(40.1)(p)	170.3

See accompanying notes to unaudited pro forma condensed consolidated financial statements

TARGA RESOURCES PARTNERS LP
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2013

	Targa Resources Partners LP	Atlas Pipeline Partners, L.P.	Pro Forma Adjustments	Targa Resources Partners LP Pro Forma
	(In millions)			
Revenues	$ 6,314.9	$ 2,106.8	$ (0.0)(h)	$ 8,421.7
Costs and expenses:				
Product purchases	5,137.2	1,690.4	(0.0)(h)	6,827.6
Operating expenses	376.2	94.5	—	470.7
Depreciation and amortization expenses	271.6	168.6	(0.2)(i)	572.8
			132.8 (j)	
General and administrative expenses	143.1	60.9	(5.0)(k)	187.2
			(11.8)(l)	
Other operating (income) expense	9.6	21.5	—	31.1
Income from operations	377.2	70.9	(115.8)	332.3
Other income (expense):				
Interest expense, net	(131.0)	(89.6)	7.4 (n)	(213.2)
Equity earnings (loss)	14.8	(4.7)	(5.0)(m)	5.1
Loss on debt repurchases and amendments	(14.7)	—	—	(14.7)
Gain (loss) on early debt extinguishment	—	(26.6)	—	(26.6)
Other	15.2	(43.9)	43.9 (g)	15.2
Income before income taxes	261.5	(93.9)	(69.5)	98.1
Income tax (expense) benefit:	(2.9)	2.3	—	(0.6)
Net income	258.6	(91.6)	(69.5)	97.5
Less: Net income attributable to noncontrolling interests	25.1	7.0	—	32.1
Preferred unit dividend effect	—	29.5	(29.5)(b)	—
Preferred unit dividends in kind	—	23.6	(23.6)(b)	—
Preferred unit dividends	—	—	—	—
Net income attributable to limited partners and general partner	$ 233.5	$ (151.7)	$ (16.4)	$ 65.4
Net income attributable to general partner	$ 107.5		$ (40.9)(o)	$ 66.6
Net income attributable to limited partners	126.0		(127.2)(o)	(1.2)
Net income attributable to Targa Resources Partners LP	$ 233.5		$ (168.1)	$ 65.4
Net income per limited partner unit - basic	$ 1.19			$ (0.01)
Net income per limited partner unit - diluted	$ 1.19			$ (0.01)
Weighted average limited partner units outstanding - basic	105.5	74.4	(25.6)(p)	154.3
Weighted average limited partner units outstanding - diluted	105.7	74.4	(25.6)(p)	154.5

See accompanying notes to unaudited pro forma condensed consolidated financial statements

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 - Basis of Pro Forma Presentation

Item 9.01 of Form 8-K requires that we provide the following pro forma financial statements applicable to the APL acquisition:

- Unaudited pro forma condensed consolidated statements of operations for the year ended December 31, 2013, and for the six months ended June 30, 2014 prepared as if the APL acquisition occurred as of January 1, 2013.
- Unaudited pro forma condensed consolidated balance sheet as of June 30, 2014, prepared as if the APL acquisition occurred as of the balance sheet date.

Under Securities and Exchange Commission ("SEC") regulations, pro forma adjustments to our statements of operations are limited to those that are (1) directly attributable to the acquisition, (2) factually supportable and (3) expected to have a continuing impact. As such, in preparing the unaudited pro forma condensed consolidated statements of operations we have combined our reported results with those of the acquired company and made adjustments to:

- exclude the financial results of assets sold by APL prior to our acquisition;
- conform the seller's reported results of operations to our policies;
- include incremental depreciation and amortization associated with fair value adjustments under the acquisition method of accounting for business acquisitions;
- eliminate the impact of historical transactions between APL and us; and
- include the financing costs applicable to the financing transactions for the APL transaction described above.

Under SEC regulations, pro forma adjustments to our balance sheet are limited to those that give effect to events that are directly attributable to the acquisition and are factually supportable regardless of whether they have a continuing impact or are nonrecurring. As such in preparing the unaudited pro forma condensed consolidated balance sheet, we have utilized our previously reported unaudited balance sheet as June 30, 2014 and made adjustments to:

- incorporate the fair values of the assets and liabilities acquired based on our preliminary APL acquisition valuation;
- present the impact of the merger consideration paid in cash and via common unit exchange, as well as the preferred unit redemptions and conversions described above;
- reflect our incremental borrowings to finance activities directly related to the APL acquisition; and
- accrue acquisition related expenses.

The Partnership accounts for business combinations pursuant to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 805, *Business Combinations*. The unaudited pro forma condensed consolidated financial statements reflect preliminary estimates of the fair values of assets acquired and liabilities assumed based on the application of ASC 805. The fair values assigned to APL's tangible and intangible assets acquired and liabilities assumed are based on management's estimates and assumptions. The estimated fair values of these assets acquired and liabilities assumed are considered preliminary and are based on the information that was available as of the date of the MLP Merger Agreement. These fair value estimates may be revised after the transactions close to reflect the final valuation based on updated information and revised assumptions. The unaudited pro forma condensed consolidated financial statements are not necessarily indicative of the results that actually would have occurred if the Partnership had completed the transactions on the dates indicated or which could be obtained in the future. The unaudited pro forma condensed consolidated financial statements should be read in conjunction with these notes accompanying the unaudited pro forma condensed consolidated financial statements and with the historical consolidated financial statements.

Note 2 - Acquisition of Atlas Pipeline Partners, L.P.

On October 13, 2014, the Partnership and APL entered into the MLP Merger Agreement. The acquisition is currently expected to close in the first quarter of 2015. The pro forma fair value of the consideration transferred for APL was approximately $5.6 billion, which consisted of the following:

Purchase price:	
APL Equity Value	$3,636.3
Cash payment to APL unitholders ($1.26 per unit multiplied by 98.5 million units at June 30, 2014)	124.1
APL redeems Class E Preferred Units at APL Effective Time; Targa deposits the funds	126.5
Management change of control payments	28.6
Total purchase consideration	$3,915.5
Debt outstanding (as of June 30, 2014):	
APL Senior Notes due 2020, 2021 and 2023	$1,554.6
APL senior secured revolving credit facility that matures in May 2017 (the "APL Revolver")	100.0
Total debt outstanding	$1,654.6

The equity value portion of the consideration for the Partnership's common units included in these pro forma financial statements is based on the closing price of $63.78 on October 22, 2014, and calculated as follows:

Equity Value Portion of Consideration		
APL Unit Count as of:		**June 30, 2014**
Common Units		82.2
Class D Preferred Units		14.4
Phantom Units		1.9
Total Fully Diluted Units (Excluding Class E)		98.5
Closing Share Price of NGLS		
October 22, 2014	$	63.78
Fixed exchange ratio	x	0.5846
	$	37.29
Total Fully Diluted Units (Excluding Class E)	x	98.5
APL Equity Value, fully diluted (Excluding Class E)		3,671.4
Less: value of estimated unvested portion of APL phantom units converted to TRP LTIP units		(35.1)
APL Equity Value	$	3,636.3

Under ASC 805, registrants are to use the most recent stock price at the time of filing for determining the value of stock to be issued in a transaction that has not yet consummated. The fair value of the APL Unit Consideration for the Partnership's common units will fluctuate until the closing date as a result of fluctuations in the market price of the Partnership's common units. A hypothetical increase (decrease) of 10% in the Partnership's unit price would increase (decrease) the equity value portion of the consideration by $367.1 million.

Note 3 - Pro Forma Adjustments and Assumptions

The unaudited pro forma condensed consolidated financial statements include adjustments required under SEC regulations as follows:

(a) Reflects the preliminary allocation of the total purchase price paid by us. This allocation is subject to further assessment and adjustments pending additional information sharing between the parties, third-party appraisals and other potential adjustments. Preliminary allocation of purchase price:

Preliminary allocation of purchase price:	2014	Lives (In years)
Cash and cash equivalents (1)	$ 4.1	NA
Trade receivables, net (1)	254.9	NA
Other current assets (1)	26.5	NA
Property, plant and equipment (2) (3)	2,984.2	30
Investment in unconsolidated affiliate (2)	179.0	NA
Goodwill (2)	—	NA
Intangible assets (2) (3)	2,656.1	20
Other long-term assets (2) (3)	6.7	NA
Current liabilities, less current portion of long term debt (1)	(399.3)	NA
Long term debt (2) (3)	(1,685.3)	NA
Other long-term liabilities (2)	(39.6)	NA
Noncontrolling interest in subsidiaries (2)	(71.8)	NA
Net tangible and intangible assets acquired	$ 3,915.5	

(1) Management anticipates that the fair values of working capital items approximate their carrying values.

(2) The fair values of assets acquired and liabilities assumed are considered preliminary and are based on the information that was available as of the execution of the merger agreement. Therefore, the fair values determined for these items may change significantly as additional information is obtained during the merger process.

(3) The preliminary fair value adjustments to historical APL book values include: (i) an increase to intangible assets of $2,022.0 million; (ii) a decrease to other long term assets for the write-off of debt issuance costs of $37.7 million; and (iii) an increase to long term debt of $30.7 million. At this time, no assumptions have been made regarding the fair value of property, plant and equipment until detailed valuation appraisals are prepared.

(b) Reflects redemption of Class E Perpetual Preferred units, which had a book value of $121.9 million at June 30, 2014, for $126.5 million, which represents their redemption price of $25.00 per unit. Additionally reflects the conversion of the $493.6 million of Class D Preferred Units to Common Units and the elimination of the impact of preferred unit dividends on Net Income attributable to limited partners.

(c) The following table reflects the estimated sources and uses of cash for the acquisition:

Sources	
Proceeds from long term debt:	
Borrowings under existing TRP Revolver (1)	$ 304.7
General Partner contribution of cash to maintain its 2% ownership interest in TRP as of June 30, 2014	74.5
Total sources of cash	$ 379.2
Uses	
Redemption of Class E Preferred at $25.00 per unit redemption price	$(126.5)
Cash payment to APL unitholders ($1.26 per unit multiplied by 98.5 million units at June 30, 2014)	(124.1)
Payment of management change of control payments associated with APL	(28.6)
Payoff of APL Revolver Borrowings as of June 30, 2014.	(100.0)
Total uses of cash	$(379.2)

(1) Borrowings under the variable rate Senior Secured Credit Facility Due October 3, 2017 (the “TRP Revolver”)

(d) Reflects the Partnership’s application of cash received from the general partner contribution (see note c) to reduce its borrowings under the TRP Revolver, as well as elimination of APL general partner unitholders’ historical equity.

(e) Reflects the common units issued as consideration to APL unitholders based on the equity value of transaction of $3,636.3 million, as well as the elimination of APL unitholders’ historical equity value of $1,666.4 million for common units and $493.6 million for the Class E preferred units converted to common units in conjunction with this transaction.

(f) Reflects the accrual of estimated acquisition-related transaction costs including legal, accounting, banking and other fees that are directly attributable to the transaction. The allocation of costs to the general partners is based on the 2% general partnership interest.

(g) Reflects the elimination of APL's historical goodwill, the elimination of the impact of the impairment of goodwill on the statement of operations for the year ended December 31, 2013, and the preliminary estimate of goodwill for the Partnership's acquisition of APL.

(h) Reflects the elimination of third party transactions between the Partnership and APL, which are intercompany transactions on a pro forma basis. Amounts are less than $50 thousand for both periods presented.

(i) Reflects the change in depreciation expense over the periods presented as a result of the acquisition.

	Estimated Book Value	Useful Lives (in years) (1)
Property, plant and equipment	$ 2,984.2	30

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
Reversal of depreciation recorded at APL	$ (56.3)	$ (99.7)
Depreciation expense based on the book value	49.7	99.5
	$ (6.6)	$ (0.2)

(1) For purposes of these pro forma financial statements, we have utilized the straight-line depreciation method and assumed an estimated useful life of 30 years for plant, property and equipment. We will subsequently determine the depreciation methods and estimated useful lives of the tangible assets of this acquisition. A five year change in estimated useful lives of depreciable tangible assets would result in a change to revised pro forma straight-line depreciation expense for the year ended December 31, 2013 as shown in the table below:

	Useful Lives	
	25 Years	35 Years
Increase (decrease) in depreciation of property, plant and equipment		
Year ended December 31, 2013	$ 19.9	$ (14.2)

(j) Reflects the difference between the historical balances of APL's intangible assets, net, and our preliminary estimate of intangible assets acquired in connection with the acquisition. Additionally, reflects the change in amortization expense over the periods presented.

	Estimated New Book Value	Useful Lives (in years) (1)
Intangibles	$ 2,656.1	20

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
Amortization expense based on the new book value	$ 66.4	$ 132.8

(1) For purposes of these pro forma financial statements, we have utilized the straight-line amortization method and assumed an estimated useful life of 20 years for intangible assets, which is consistent with the useful lives of the Partnership's existing intangible assets. We will subsequently determine the amortization method and estimated useful lives of the intangible assets of this acquisition. A five year change in estimated useful lives of definite-lived amortizable intangible assets would result in a change to revised pro forma straight-line amortization expense for the year ended December 31, 2013 as shown in the table below:

	Useful Lives	
	15 Years	**25 Years**
Increase (decrease) in amortization of intangible assets		
Year ended December 31, 2013	$ 44.3	$ (26.6)

(k) Reflects the elimination of $2.5 million for the six months ended June 30, 2014 and $5.0 million for the year ended December 31, 2013 for compensation reimbursements to ATLS for executives not part of the acquired company. The financial effect and timing of the elimination of costs are certain. The allocation of general and administrative expenses from TRC to the Partnership is not expected to be materially impacted by the merger, as the Partnership already receives a full allocation of similar executive stewardship costs, which would not change due to the APL acquisition.

(l) Reflects the estimated stock-based compensation expense related to the fair value of the unvested portion of replacement Partnership LTIP awards to be issued to APL Phantom Unitholders in connection with the acquisition. The compensation expense is recognized over the estimated remaining vesting periods, and replaces the historical stock-based compensation expense recorded by APL for Phantom units.

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
APL Phantom Unit Expense	(12.9)	(19.3)
TRP LTIP Estimated Expense	8.5	7.5
	(4.4)	(11.8)

(m) APL sold its 20% interest in West Texas LPG Pipeline Limited Partnership ("WTLPG") in May 2014. These adjustments reflect the elimination of the Gain on Sale of WTLPG in 2014, as well as the equity earnings of WTLPG in 2014 and 2013.

(n) Reflects additional interest expense on net borrowings under the TRP Revolver in connection with the acquisition, at historical weighted average rates for the revolving credit facilities:

Pro forma interest expense:	Six Months Ended June 30, 2014	Year Ended December 31, 2013
Interest expense on the TRP Revolver (2.1% for 2014 and 2.4% for 2013; principal of $304.7 million)	$ 3.2	$ 7.3
Less: Interest expense on the APL Revolver (3.2% for 2014 and 4.0% for 2013; principal of $100.0 million)	(1.6)	(4.0)
Less: Amortization of debt issue costs written off in purchase accounting	(3.7)	(7.0)
Amortization of premium implied by FV adjustment to debt of $30.7 million over terms of Senior Notes	(1.8)	(3.7)
Pro forma interest expense adjustments for the acquisition	$ (3.9)	$ (7.4)

A 1⁄8 percent variance in the interest rates for the TRP Revolver would have increased or decreased pro forma interest expense by $0.2 million for the six months ended June 30, 2014 and $0.4 million for the year ended December 31, 2013.

(o) Reflects the adjustment of net income attributable to general and limited partners to give effect to the impact of pro forma adjustments, as well as the pro forma reduction of the general partners' incentive distribution rights by fixed amounts of $37.5 million for the year ended December 31, 2013 and $12.5 million for the six months ended June 30, 2014.

(p) Reflects adjustments to weighted average basic and diluted units to give effect to each APL common unitholder entitled to receive 0.5846 common units of TRP in connection with the APL transaction:

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
APL Weighted average limited partner units outstanding - basic	80.8	74.4
APL Weighted average Class D Preferred (to be converted to units)	14.1	9.1
	94.9	83.5
Fixed exchange ratio	x 0.5846	x 0.5846
	55.5	48.8
TRP Weighted average limited partner units outstanding - basic	113.3	105.5
	168.8	154.3
APL Weighted average limited partner units outstanding - diluted	96.5	74.4
APL Weighted average Class D Preferred (to be converted to units) - presented as antidilutive for 2013	n/a	9.1
	96.5	83.5
Fixed exchange ratio	x 0.5846	x 0.5846
	56.4	48.8
TRP Weighted average limited partner units outstanding - diluted	113.9	105.7
	170.3	154.5

Note 4 – Additional Pro Forma Information

On May 7, 2013, APL acquired 100% of the equity interests of TEAK Midstream, LLC, which was a significant business combination for APL. The following information presents the incremental immaterial impact of the acquisition of TEAK Midstream, LLC, on the results of APL (as adjusted further for TRP's financing and equity structure) on a pro forma basis, as if the acquisition had occurred on January 1, 2013:

	For the period from January 1 to May 7, 2013
Revenues	$ 36.1
Costs and expenses:	
Product purchases	(26.8)
Operating expenses	(3.9)
General and administrative expense	(1.6)
Equity loss	(2.7)
Gain on asset sale	0.3
Net income to limited partners and general partner	$ 1.4