Energy Transfer Partners, L.P.
Form 10-Q
November 08, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

or

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

Commission file number 1-11727

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

Delaware (state or other jurisdiction of incorporation or organization)	73-1493906 (I.R.S. Employer Identification No.)

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Address of principal executive offices) (zip code)
(214) 981-0700
(Registrant's telephone number, including area code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

At October 31, 2012, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	300,547,400	Common Units

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Energy Transfer Partners, L.P. and Subsidiaries

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (“Energy Transfer Partners,” the “Partnership,” or "ETP") in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “esti “goal,” “forecast,” “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership’s actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Part II — Other Information – Item 1A. Risk Factors” in this Quarterly Report on Form 10-Q and our Quarterly Report on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012, as well as “Part I — Item 1A. Risk Factors” in the Partnership’s Report on Form 10-K for the year ended December 31, 2011 filed with the Securities and Exchange Commission on February 22, 2012.

Definitions

The following is a list of certain acronyms and terms generally used throughout this document:

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Bbls	barrels
Bcf	billion cubic feet
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
CAA	Clean Air Act
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
DOT	U.S. Department of Transportation
El Paso	El Paso Corporation
Enterprise	Enterprise Products Partners L.P., together with its subsidiaries
ETC Compression	ETC Compression, LLC

ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
EPA	U.S. Environmental Protection Agency

Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
Holdco	ETP Holdco Corporation
HOLP	Heritage Operating, L.P.
ICA	Interstate Commerce Act
IDRs	incentive distribution rights
LDH	LDH Energy Asset Holdings LLC
LIBOR	London Interbank Offered Rate
Lone Star	Lone Star NGL LLC
MMBtu	million British thermal units
NGA	Natural Gas Act
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OTC	over-the-counter
OSHA	federal Occupational Safety and Health Act
PCBs	polychlorinated biphenyls
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs
SEC	Securities and Exchange Commission

Southern Union	Southern Union Company, a subsidiary of ETE
Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Tcf	trillion cubic feet
Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on proportionate ownership.

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PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$110,354	$106,816
Accounts receivable, net of allowance for doubtful accounts of $538 and $7,651 as of September 30, 2012 and December 31, 2011, respectively	541,345	568,579
Accounts receivable from related companies	45,165	81,753
Inventories	234,203	306,740
Exchanges receivable	18,837	18,808
Price risk management assets	18,007	11,429
Current assets held for sale	7,482	—
Other current assets	114,324	181,369
Total current assets	1,089,717	1,275,494
PROPERTY, PLANT AND EQUIPMENT	14,238,264	13,983,888
ACCUMULATED DEPRECIATION	(1,379,944)	(1,677,522)
	12,858,320	12,306,366
NON-CURRENT ASSETS HELD FOR SALE	190,996	—
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,197,520	200,612
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	41,879	25,537
GOODWILL	600,152	1,219,597
INTANGIBLE ASSETS, net	161,847	331,409
OTHER NON-CURRENT ASSETS, net	157,129	159,601
Total assets	$18,297,560	$15,518,616

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	September 30, 2012	December 31, 2011
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$381,338	$401,053
Accounts payable to related companies	7,977	33,373
Exchanges payable	13,822	17,906
Price risk management liabilities	88,770	79,518
Accrued and other current liabilities	723,135	629,202
Current maturities of long-term debt	350,000	424,117
Current liabilities held for sale	5,439	—
Total current liabilities	1,570,481	1,585,169
LONG-TERM DEBT, less current maturities	8,690,740	7,388,170
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	72,660	42,303
OTHER NON-CURRENT LIABILITIES	174,351	152,550
COMMITMENTS AND CONTINGENCIES (Note 14)		
EQUITY:		
General Partner	190,237	181,646
Limited Partners:		
Common Unitholders	6,733,310	5,533,492
Accumulated other comprehensive income (loss)	(10,351)	6,569
Total partners' capital	6,913,196	5,721,707
Noncontrolling interest	876,132	628,717
Total equity	7,789,328	6,350,424
Total liabilities and equity	$18,297,560	$15,518,616

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit data)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
REVENUES:				
Natural gas sales	$603,449	$679,889	$1,480,729	$1,963,135
NGL sales	326,841	333,078	1,011,735	756,740
Gathering, transportation and other fees	399,494	392,080	1,162,386	1,094,762
Retail propane sales	—	213,496	87,082	962,258
Other	90,690	82,920	198,830	217,085
Total revenues	1,420,474	1,701,463	3,940,762	4,993,980
COSTS AND EXPENSES:				
Cost of products sold	886,888	1,070,076	2,319,318	3,067,316
Operating expenses	99,602	193,364	349,465	563,917
Depreciation and amortization	94,812	106,419	282,485	294,356
Selling, general and administrative	47,295	57,745	151,310	158,000
Total costs and expenses	1,128,597	1,427,604	3,102,578	4,083,589
OPERATING INCOME	291,877	273,859	838,184	910,391
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(112,141)	(124,000)	(383,271)	(347,706)
Equity in earnings of unconsolidated affiliates	7,920	6,713	63,011	13,386
Gain on deconsolidation of Propane Business	—	—	1,056,709	—
Loss on extinguishment of debt	—	—	(115,023)	—
Losses on non-hedged interest rate derivatives	(65)	(68,595)	(8,087)	(64,705)
Other, net	6,548	(6,345)	9,547	(6,559)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	194,139	81,632	1,461,070	504,807
Income tax expense	768	4,039	14,915	20,417
INCOME FROM CONTINUING OPERATIONS	193,371	77,593	1,446,155	484,390
Loss from discontinued operations	(147,162)	(1,543)	(150,062)	(4,522)
NET INCOME	46,209	76,050	1,296,093	479,868
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	9,184	9,285	32,914	17,673
NET INCOME ATTRIBUTABLE TO PARTNERS	37,025	66,765	1,263,179	462,195
GENERAL PARTNER'S INTEREST IN NET INCOME	116,583	104,810	341,925	318,241
LIMITED PARTNERS' INTEREST IN NET INCOME (LOSS)	$(79,558)	$(38,045)	$921,254	$143,954
INCOME (LOSS) FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:				
Basic	$0.26	$(0.18)	$4.54	$0.70
Diluted	$0.26	$(0.18)	$4.52	$0.70
NET INCOME (LOSS) PER LIMITED PARTNER UNIT:				
Basic	$(0.33)	$(0.19)	$3.91	$0.68
Diluted	$(0.33)	$(0.19)	$3.89	$0.68

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income	$46,209	$76,050	$1,296,093	$479,868
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(3,539)	(4,994)	(13,636)	(27,405)
Change in value of derivative instruments accounted for as cash flow hedges	(3,363)	6,126	10,508	14,583
Change in value of available-for-sale securities	—	(900)	(114)	(935)
Change in other comprehensive income (loss) from equity investments	8,728	—	(13,678)	—
	1,826	232	(16,920)	(13,757)
Comprehensive income	48,035	76,282	1,279,173	466,111
Less: Comprehensive income attributable to noncontrolling interest	9,184	9,285	32,914	17,673
Comprehensive income attributable to partners	$38,851	$66,997	$1,246,259	$448,438

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2012
(Dollars in thousands)
(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2011	$181,646	$5,533,492	$ 6,569	$ 628,717	$6,350,424
Distributions to partners	(333,053)	(626,545)	—	—	(959,598)
Distributions to noncontrolling interest	—	—	—	(38,794)	(38,794)
Units issued for cash	—	771,813	—	—	771,813
Capital contributions from noncontrolling interest	—	—	—	253,295	253,295
Units issued in connection with acquisitions	—	112,000	—	—	112,000
Non-cash compensation expense, net of units tendered by employees for tax withholdings	19	30,266	—	—	30,285
Other comprehensive loss, net of tax	—	—	(16,920)	—	(16,920)
Other, net	(300)	(8,970)	—	—	(9,270)
Net income	341,925	921,254	—	32,914	1,296,093
Balance, September 30, 2012	$190,237	$6,733,310	$ (10,351)	$ 876,132	$7,789,328

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Nine Months Ended September 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$1,296,093	$479,868
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	282,485	294,356
Amortization of finance costs charged to interest	7,774	7,199
Loss on extinguishment of debt	115,023	—
Non-cash compensation expense	30,190	31,139
Gain on deconsolidation of Propane Business	(1,056,709)	—
Write-down of assets included in loss from discontinued operations (see Note 3)	145,214	—
Distributions on unvested awards	(6,049)	(5,687)
Equity in earnings of unconsolidated affiliates	(63,011)	(13,386)
Distributions from unconsolidated affiliates	93,792	15,563
Other non-cash	32,869	26,110
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation (see Note 4)	60,264	195,047
Net cash provided by operating activities	937,935	1,030,209
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for Citrus Merger (See Note 6)	(1,895,000)	—
Cash proceeds from contribution and sale of propane operations	1,442,536	—
Cash paid for all other acquisitions, net of cash received	(10,317)	(1,971,438)
Capital expenditures (excluding allowance for equity funds used during construction)	(1,797,467)	(950,978)
Contributions in aid of construction costs	28,022	18,435
Contributions to unconsolidated affiliates	(2,050)	(221,365)
Distributions from unconsolidated affiliates in excess of cumulative earnings	95,184	15,731
Proceeds from the sale of assets	13,172	6,516
Net cash used in investing activities	(2,125,920)	(3,103,099)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	4,462,287	5,283,107
Repayments of long-term debt	(3,266,160)	(3,644,454)
Net proceeds from issuance of Limited Partner units	771,813	799,292
Capital contributions received from noncontrolling interest	240,115	616,311
Distributions to partners	(959,598)	(863,511)
Distributions to noncontrolling interest	(38,794)	(18,900)
Debt issuance costs	(18,140)	(12,262)
Net cash provided by financing activities	1,191,523	2,159,583
INCREASE IN CASH AND CASH EQUIVALENTS	3,538	86,693
CASH AND CASH EQUIVALENTS, beginning of period	106,816	49,540
CASH AND CASH EQUIVALENTS, end of period	$110,354	$136,233

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts, except per unit data, are in thousands)
(unaudited)

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Partners, L.P. and its subsidiaries ("Energy Transfer Partners," the "Partnership," "we" or "ETP") are managed by ETP's general partner, ETP GP, which is in turn managed by its general partner, ETP LLC. ETE, a publicly traded master limited partnership, owns ETP LLC, the general partner of our General Partner. The consolidated financial statements of the Partnership presented herein include our operating subsidiaries described below.

Business Operations

Our activities are primarily conducted through our operating subsidiaries (collectively, the "Operating Companies") as follows:

- ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia. Our intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC FEP, a Delaware limited liability company that directly owns a 50% interest in the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry Energy, LLC, a Delaware limited liability company that indirectly owns a 50% interest in Citrus Corp., which owns 100% of the FGT interstate natural gas pipeline.
- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

On January 12, 2012, we contributed HOLP and Titan, our subsidiaries that formerly operated our propane operations, to AmeriGas. See Note 6.

On October 5, 2012, we completed the Sunoco Merger and Holdco Transaction, as described below in Note 3.

Our historical financial statements reflect the following reportable business segments: intrastate natural gas transportation and storage; interstate natural gas transportation; midstream; NGL transportation and services; and retail propane and other retail propane related operations.

Preparation of Interim Financial Statements

The accompanying consolidated balance sheet as of December 31, 2011, which has been derived from audited financial statements, and the unaudited interim consolidated financial statements and notes thereto of the Partnership as of September 30, 2012 and for the three and nine month periods ended September 30, 2012 and 2011, have been prepared in accordance with GAAP for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership's operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

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In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of the Partnership as of September 30, 2012, and the Partnership's results of operations and cash flows for the three and nine months ended September 30, 2012 and 2011. The unaudited interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2011, as filed with the SEC on February 22, 2012.
Certain prior period amounts have been reclassified to conform to the 2012 presentation. These reclassifications had no impact on net income or total equity.

2. ESTIMATES:
The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.
The natural gas industry 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 for our natural gas and NGL related operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the estimated operating results represent the actual results in all material respects.
Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual values and results could differ from those estimates.

3. ACQUISITIONS AND DIVESTITURES:
Sunoco Merger
On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly-owned subsidiary of ETP, completed its merger with Sunoco, Inc. ("Sunoco"). Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 54,971,724 ETP Common Units and a total of approximately $2.6 billion in cash.
Sunoco generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States. Prior to October 5, 2012, Sunoco also owned a 2% general partner interest, 100% of the IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. As discussed below, on October 5, 2012, Sunoco's interests in Sunoco Logistics were transferred to the Partnership.
Sunoco Logistics is a publicly traded limited partnership that owns and operates a logistics business consisting of a geographically diverse portfolio of complementary pipeline, terminalling and crude oil acquisition and marketing assets. The refined products pipelines business consists of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in refined products pipelines. The crude oil pipeline business consists of crude oil pipelines located principally in Oklahoma and Texas. The terminal facilities business consists of refined products and crude oil terminal capacity at the Nederland Terminal on the Gulf Coast of Texas and capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey. The crude oil acquisition and marketing business, principally conducted in Oklahoma and Texas, involves the acquisition and marketing of crude oil and consists of crude oil transport trucks and crude oil truck unloading facilities.
ETP incurred merger related costs related to the Sunoco Merger of $5.7 million and $12.0 million for the three and nine months ended September 30, 2012, respectively.
Holdco Transaction

Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation (“Holdco”), an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco to Holdco and will retain a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90,706,000 Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units are entitled to 35% of the quarterly cash distribution generated by ETP and its subsidiaries other than Holdco, subject to a

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maximum cash distribution of $3.75 per Class F Unit per year, which is the current level. Pursuant to a stockholders agreement between ETE and ETP, ETP will control Holdco. Consequently, ETP will consolidate Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction. Under the terms of the Holdco transaction agreement, ETE will relinquish an aggregate of $210 million of incentive distributions over 12 consecutive quarters following the closing of the Holdco Transaction. The relinquishment will apply to the distribution to be paid with respect to the third quarter ended September 30, 2012.

Discontinued Operations

In October 2012, we sold ETC Canyon Pipeline, LLC ("Canyon") for approximately $207 million. For the three and nine months ended September 30, 2012, the results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been restated to present Canyon's operations as discontinued operations in the consolidated statements of operations. Canyon's assets and liabilities have been reclassified and reported as assets and liabilities held for sale as of September 30, 2012. A $145 million non-cash write-down of the carrying amounts of the Canyon assets to net recoverable value was recorded during the three months ended September 30, 2012.

4. CASH AND CASH EQUIVALENTS:

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

The net change in operating assets and liabilities (net of effects of acquisitions and deconsolidation) included in cash flows from operating activities is comprised as follows:

	Nine Months Ended September 30, 2012	2011
Accounts receivable	$(112,276)	$28,318
Accounts receivable from related companies	(68,828)	(22,917)
Inventories	(26,047)	67,716
Exchanges receivable	(578)	6,300
Other current assets	73,228	(25,956)
Other non-current assets, net	5,088	7,061
Accounts payable	48,120	(11,333)
Accounts payable to related companies	85,943	(804)
Exchanges payable	(3,909)	231
Accrued and other current liabilities	42,561	78,997
Other non-current liabilities	(5,362)	1,298
Price risk management assets and liabilities, net	22,324	66,136
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation	$60,264	$195,047

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Non-cash investing and financing activities are as follows:

	Nine Months Ended September 30, 2012	2011
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$383,426	$128,874
AmeriGas limited partner interests received in exchange for contribution of Propane Business (See Note 6)	$1,123,003	$—
NON-CASH FINANCING ACTIVITIES:		
Contributions receivable related to noncontrolling interest	$13,180	$—
Issuance of common units in connection with acquisitions	$112,000	$3,000
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$—	$4,166

5. INVENTORIES:

Inventories consisted of the following:

	September 30, 2012	December 31, 2011
Natural gas and NGLs, excluding propane	$151,387	$144,251
Propane	—	86,958
Appliances, parts and fittings and other	82,816	75,531
Total inventories	$234,203	$306,740

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory and designate certain of these derivatives as fair value hedges for accounting purposes. Changes in fair value of the designated hedged inventory have been recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

6. INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Citrus Merger

On March 26, 2012, ETE consummated the acquisition of Southern Union and, concurrently with the closing of the Southern Union acquisition, CrossCountry Energy, LLC (“CrossCountry”), a subsidiary of Southern Union that indirectly owned a 50% interest in Citrus Corp. (“Citrus”), merged with a subsidiary of ETP and, in connection therewith, ETP paid approximately $1.9 billion in cash and issued $105.0 million of ETP Common Units (the “Citrus Merger”) to a subsidiary of ETE. As a result of the consummation of the Citrus Merger, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc.

Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

We recorded our investment in Citrus at $2.0 billion, which exceeded our proportionate share of Citrus' equity by $1.03 billion, all of which is treated as equity method goodwill due to the application of regulatory accounting.

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the “Propane Business”) to AmeriGas. We received approximately $1.46 billion in cash and approximately 29.6 million AmeriGas Common Units valued at $1.12 billion at the time of the contribution. In addition, AmeriGas assumed approximately $71.0 million of existing HOLP debt. We recognized a gain on deconsolidation of $1.06 billion as a result of this transaction. The cash proceeds were used to complete our tender offer of existing debt (see Note 10) in January 2012 and to repay borrowings on our revolving credit facility.

Our investment in AmeriGas reflected $630.0 million in excess of our proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $288.6 million is being amortized over a weighted average period of 14 years, and $341.4 million is being treated as equity method goodwill and non-amortizable intangible assets.

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In connection with the closing of this transaction, we entered into a support agreement with AmeriGas (See Note 14). Under a unitholder agreement with AmeriGas, we are also obligated to hold the approximately 29.6 million AmeriGas Common Units that we received in this transaction until January 2013.

We have not reflected our Propane Business as discontinued operations as a result of our investment in AmeriGas.

In June 2012, we sold the remainder of our retail propane operations, consisting of our cylinder exchange business, to a third party. In connection with the contribution agreement with AmeriGas, certain excess sales proceeds from the sale of the cylinder exchange business were remitted to AmeriGas, and we received net proceeds of approximately $43.0 million.

7. GOODWILL AND INTANGIBLE ASSETS:

A net decrease in goodwill of $619.4 million was recorded during the nine months ended September 30, 2012 primarily due to the contribution of our Propane Business to AmeriGas. See Note 6.

Components and useful lives of intangible assets were as follows:

	September 30, 2012		December 31, 2011	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$219,825	$(59,162)	$338,424	$(95,239)
Noncompete agreements	—	—	15,431	(7,835)
Patents (9 years)	750	(264)	750	(201)
Other (10 to 15 years)	843	(145)	1,320	(580)
Total amortizable intangible assets	221,418	(59,571)	355,925	(103,855)
Non-amortizable intangible assets:				
Trademarks	—	—	79,339	—
Total intangible assets	$221,418	$(59,571)	$435,264	$(103,855)

Aggregate amortization expense of intangible assets was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Reported in depreciation and amortization	$3,664	$7,267	$12,129	$17,683

Estimated aggregate amortization expense for the next five years is as follows:

2012 (remainder)	$3,523
2013	11,271
2014	10,146
2015	10,146
2016	10,146

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review goodwill and non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of August 31 for reporting units within our intrastate transportation and storage and midstream segments and as of December 31 for all other segments. We have not completed our annual impairment tests for 2012 and have not recorded any impairments related to amortizable intangible assets during the nine months ended September 30, 2012.

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8. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations. During the period ended September 30, 2012, no transfers were made between any levels within the fair value hierarchy.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value of our consolidated debt obligations at September 30, 2012 and December 31, 2011 was $10.23 billion and $8.39 billion, respectively. As of September 30, 2012 and December 31, 2011, the aggregate carrying amount of our consolidated debt obligations was $9.04 billion and $7.81 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of September 30, 2012 and December 31, 2011 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at September 30, 2012	
		Level 1	Level 2
Financial Assets:			
Marketable securities (included in other current assets)	$6	$6	$—
Interest rate derivatives	54,479	—	54,479
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	30,102	30,102	—
Swing Swaps IFERC	14,260	172	14,088
Fixed Swaps/Futures	84,383	84,383	—
Options — Puts	2,322	—	2,322
Options — Calls	1,790	—	1,790
Forward Physical Contracts	2,223	—	2,223
Power:			
Forwards	6,176	—	6,176
Futures	374	374	—
Options — Calls	2,495	—	2,495
Total commodity derivatives	144,125	115,031	29,094
Total	$198,610	$115,037	$83,573
Financial Liabilities:			
Interest rate derivatives	$(150,220)	$—	$(150,220)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(42,492)	(42,492)	—
Swing Swaps IFERC	(14,918)	(648)	(14,270)
Fixed Swaps/Futures	(104,316)	(104,316)	—
Options — Puts	(672)	—	(672)
Options — Calls	(2,134)	—	(2,134)
Forward Physical Contracts	(2,082)	—	(2,082)
Power:			
Forwards	(5,865)	—	(5,865)
Futures	(605)	(605)	—
Options — Calls	(2,106)	—	(2,106)
Total commodity derivatives	(175,190)	(148,061)	(27,129)
Total	$(325,410)	$(148,061)	$(177,349)

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	Fair Value Total	Fair Value Measurements at December 31, 2011	
		Level 1	Level 2
Financial Assets:			
Marketable securities (included in other current assets)	$1,229	$1,229	$—
Interest rate derivatives	36,301	—	36,301
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	62,924	62,924	—
Swing Swaps IFERC	15,002	1,687	13,315
Fixed Swaps/Futures	214,572	214,572	—
Options — Puts	6,435	—	6,435
Forward Physical Contracts	699	—	699
Propane – Forwards/Swaps	9	—	9
Total commodity derivatives	299,641	279,183	20,458
Total	$337,171	$280,412	$56,759
Financial Liabilities:			
Interest rate derivatives	$(117,020)	$—	$(117,020)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(82,290)	(82,290)	—
Swing Swaps IFERC	(16,074)	(3,061)	(13,013)
Fixed Swaps/Futures	(148,111)	(148,111)	—
Options — Calls	(12)	—	(12)
Forward Physical Contracts	(712)	—	(712)
Propane – Forwards/Swaps	(4,131)	—	(4,131)
Total commodity derivatives	(251,330)	(233,462)	(17,868)
Total	$(368,350)	$(233,462)	$(134,888)

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9. NET INCOME PER LIMITED PARTNER UNIT:

Our net income for partners' capital and statements of operations presentation purposes is allocated to ETP GP and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to ETP GP, the holder of the IDRs pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to ETP GP and Limited Partners based on their respective ownership interests.

A reconciliation of income from continuing operations and weighted average units used in computing basic and diluted income from continuing operations per unit is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Income from continuing operations	$193,371	$77,593	$1,446,155	$484,390
Less: Income from continuing operations attributable noncontrolling interest	9,184	9,285	32,914	17,673
Income from continuing operations, net of noncontrolling interest	184,187	68,308	1,413,241	466,717
General Partner's interest in income from continuing operations	118,664	104,835	344,148	318,317
Limited Partners' interest in income (loss) from continuing operations	65,523	(36,527)	1,069,093	148,400
Additional earnings allocated from (to) General Partner	622	9	1,116	572
Distributions on employee unit awards, net of allocation to General Partner	(1,941)	(1,894)	(9,275)	(5,619)
Income (loss) from continuing operations available to Limited Partners	$64,204	$(38,412)	$1,060,934	$143,353
Weighted average Limited Partner units — basic	245,139,324	209,151,808	233,798,902	203,918,940
Basic income (loss) from continuing operations per Limited Partner unit	$0.26	$(0.18)	$4.54	$0.70
Dilutive effect of unvested Unit Awards	1,156,952	—	1,204,791	1,166,830
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	246,296,276	209,151,808	235,003,693	205,085,770
Diluted income (loss) from continuing operations per Limited Partner unit	$0.26	$(0.18)	$4.52	$0.70
Basic income (loss) from discontinued operations per Limited Partner unit	$(0.59)	$(0.01)	$(0.63)	$(0.02)
Diluted income (loss) from discontinued operations per Limited Partner unit	$(0.59)	$(0.01)	$(0.63)	$(0.02)

Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended September 30, 2012 are expected to be $392.7 million in total, which exceeds net income for the period by $355.7 million. Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended September 30, 2011 were $295.9 million in total, which exceeded net income for the period by $229.2 million. The allocation of the distributions in excess of net income is based on the proportionate ownership interests of the Limited Partners and General Partner. Based on this allocation approach, the distributions paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended September 30, 2012 and 2011, and as a result, net losses were allocated to the Limited Partners for the period.

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10. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	September 30, 2012	December 31, 2011
ETP Credit Facility	$491,914	$314,438
ETP Senior Notes	7,691,951	6,550,000
Transwestern Senior Notes	870,000	870,000
HOLP Senior Notes	—	71,314
Other long-term debt	—	10,345
Unamortized discounts	(20,563)	(15,457)
Fair value adjustments related to interest rate swaps	7,438	11,647
Total debt	9,040,740	7,812,287
Less: current maturities	(350,000)	(424,117)
Long-term debt, less current maturities	$8,690,740	$7,388,170

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $13.1 million in unamortized discounts and fair value adjustments related to interest rate swaps:

2012 (remainder)	$—
2013	350,000
2014	379,947
2015	750,000
2016	616,914
Thereafter	6,957,004
Total	$9,053,865

Senior Notes

In January 2012, we completed a public offering of $1.00 billion aggregate principal amount of 5.20% Senior Notes due February 1, 2022 and $1.00 billion aggregate principal amount of 6.50% Senior Notes due February 1, 2042 and used the net proceeds of $1.98 billion from the offering to fund the cash portion of the purchase price of the Citrus Merger and for general partnership purposes. We may redeem some or all of the notes at any time and from time to time pursuant to the terms of the indenture subject to the payment of a “make-whole” premium. Interest will be paid semi-annually.

In January 2012, we announced a tender offer for approximately $750.0 million aggregate principal amount of specified series of the ETP Senior Notes. The tender offer consisted of two separate offers: an Any and All Offer and a Maximum Tender Offer. The senior notes described below were repurchased under the offers for a total cost of $885.9 million and a loss on extinguishment of debt of $115.0 million was recorded during the nine months ended September 30, 2012.

In the Any and All Offer, we offered to purchase any and all of our 5.65% Senior Notes due August 1, 2012, at a fixed price. Pursuant to the Any and All Offer, we purchased $292.0 million aggregate principal amount of our 5.65% Senior Notes due August 1, 2012.

In the Maximum Tender Offer, we offered to purchase certain series of outstanding ETP Senior Notes at a fixed spread over the index rate. Pursuant to the Maximum Tender Offer, on February 7, 2012, we purchased $200.0 million aggregate principal amount of our 9.7% Senior Notes due March 15, 2019, $200.0 million aggregate principal amount of our 9.0% Senior Notes due April 15, 2019, and $58.1 million aggregate principal amount of our 8.5% Senior Notes due April 15, 2014.

Credit Facility

The indebtedness under ETP’s credit facility (the “ETP Credit Facility”) is unsecured and not guaranteed by any of the Partnership’s subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

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As of September 30, 2012, we had $491.9 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.98 billion after taking into account letters of credit of $31.9 million. The weighted average interest rate on the total amount outstanding as of September 30, 2012 was 1.72%.

ETP used approximately $2.0 billion of Sunoco's cash on hand to partially fund the cash portion of the Sunoco Merger consideration. The remainder of the cash portion of the merger consideration, approximately $620 million, was funded with borrowings under the ETP Credit Facility.

ETP as Co-Obligor of Sunoco Debt

In connection with the Sunoco Merger and Holdco Transaction, which was completed on October 5, 2012, ETP became a co-obligor on approximately $965 million of aggregate principal amount of Sunoco's existing senior notes and debentures.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements at September 30, 2012.

11. EQUITY:

Common Units Issued

The change in Common Units during the nine months ended September 30, 2012 was as follows:

	Number of Units
Outstanding at December 31, 2011	225,468,108
Common Units issued in connection with public offerings	15,525,000
Common Units issued in connection with the Equity Distribution Agreement	1,600,483
Common Units issued in connection with the Distribution Reinvestment Plan	548,708
Common Units issued in connection with acquisitions	2,404,062
Common Units issued under equity incentive plans	15,200
Outstanding at September 30, 2012	245,561,561

During the nine months ended September 30, 2012, we received proceeds from units issued pursuant to an Equity Distribution Agreement with Credit Suisse Securities (USA) LLC of $76.7 million, net of commissions, which proceeds were used for general partnership purposes. As of September 30, 2012, no Common Units remain available to be issued under this agreement.

On July 3, 2012, we issued 15,525,000 Common Units representing limited partner interests at $44.57 per Common Unit in a public offering. Net proceeds of approximately $671.1 million from the offering were used to repay amounts outstanding under the ETP Credit Facility, to fund capital expenditures related to pipeline construction projects and for general partnership purposes.

We also have a Distribution Reinvestment Plan (the "DRIP") which provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units. The registration statement we filed in connection with the DRIP covers the issuance of up to 5,750,000 Common Units under the DRIP. For the nine months ended September 30, 2012, distributions of approximately $23.9 million were reinvested under the DRIP resulting in the issuance of 548,708 Common Units. As of September 30, 2012, a total of 4,847,613 Common Units remain available to be issued under this registration statement.

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Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by us subsequent to December 31, 2011:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2011	February 7, 2012	February 14, 2012	$0.89375
March 31, 2012	May 4, 2012	May 15, 2012	0.89375
June 30, 2012	August 6, 2012	August 14, 2012	0.89375
September 30, 2012	November 6, 2012	November 14, 2012	0.89375

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to $220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012. In conjunction with the Holdco Transaction, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.

AOCI

The following table presents the components of AOCI, net of tax:

	September 30, 2012	December 31, 2011
Net gains on commodity related hedges	$3,327	$6,455
Unrealized gains on available-for-sale securities	—	114
Equity investments, net	(13,678)	—
Total AOCI, net of tax	$(10,351)	$6,569

12. UNIT-BASED COMPENSATION PLANS:

During the nine months ended September 30, 2012, employees were granted a total of 83,167 unvested awards with five-year service vesting requirements, and directors were granted a total of 6,760 unvested awards with three-year service vesting requirements. The weighted average grant-date fair value of these awards was $46.64 per unit. As of September 30, 2012 a total of 2,325,945 unit awards remain unvested, including the new awards granted during the period. We expect to recognize a total of $51.4 million in compensation expense over a weighted average period of 1.7 years related to unvested awards.

13. INCOME TAXES:

The components of the federal and state income tax expense of our taxable subsidiaries are summarized as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Current expense (benefit):				
Federal	$(9,140)	$1,125	$(9,200)	$6,788
State	2,345	2,510	9,287	11,635
Total	(6,795)	3,635	87	18,423
Deferred expense (benefit):				
Federal	7,742	872	9,033	1,876
State	(179)	(468)	5,795	118
Total	7,563	404	14,828	1,994
Total income tax expense	$768	$4,039	$14,915	$20,417

The effective tax rate differs from the statutory rate primarily due to Partnership earnings that are not subject to federal and state income taxes at the Partnership level. We expect our effective tax rate to increase as a result of the Sunoco Merger and Holdco Transaction, since Sunoco and Southern Union are corporations and are subject to federal and state income taxes.

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14. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Several FDOT/FTE projects are the subject of litigation in Broward County, Florida. On January 27, 2011, a jury awarded FGT $82.7 million and rejected all damage claims by the FDOT/FTE. On May 2, 2011, the judge issued an order entitling FGT to an easement of 15 feet on either side of its pipelines and 75 feet of temporary work space. The judge further ruled that FGT is entitled to approximately $8.0 million in interest. In addition to ruling on other aspects of the easement, he ruled that pavement could not be placed directly over FGTs' pipeline without the consent of FGT, although FGT would be required to relocate the pipeline if it did not provide such consent. While FGT would seek reimbursement of any costs associated with relocation of its pipeline in connection with an FDOT project, FGT may not be successful in obtaining such reimbursement and, as such, could be required to bear the cost of such relocation. In any such instance, FGT would seek recovery of the reimbursement costs in rates. The judge also denied all other pending post-trial motions. The FDOT/FTE filed a notice of appeal on July 12, 2011. On June 6, 2012, Florida's Fourth District Court of Appeal (“4th DCA”) issued an opinion affirming the jury award of damages and also affirming or remanding for further consideration by the trial court certain other determinations with respect to FGT's easement rights and FDOT/FTE's obligations regarding future FDOT/FTE projects. In particular, the 4th DCA affirmed that FDOT/FTE could not pave directly over our pipeline without FGTs' consent and remanded and directed the trial court to make reference in the final judgment to FDOT/FTE's obligation to seek reasonable alternatives to relocation. In addition, the 4th DCA overturned the portion of the trial court judgment defining the width of Florida Gas's easements as 15 feet on either side of its pipelines and defining the temporary work space available to Florida Gas under its easements as 75 feet in width, stating that the width of such easements and temporary work space should be determined on a case by case basis dependent on the needs of each particular relocation and whether a road improvement is a material interference with the easement. Reimbursement for any future relocation expenses will also be determined on a case by case basis. FGT has filed a petition requesting the Supreme Court of Florida to exercise its discretionary jurisdiction and to reverse the portion of the 4th DCA decision overturning the trial court judgment specifically defining the width of FGTs' easements and temporary work space. The Supreme Court of Florida has not yet decided whether to hear the case. Amounts ultimately received would primarily reduce FGTs' property, plant and equipment costs.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550.0 million in aggregate principal amount of 6.75% Senior Notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% Senior Notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the contribution of the Propane Business, ETP entered into a Contingent Residual Support Agreement ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt as defined in the CRSA.

Interstate Natural Gas Pipeline Regulation

Under the Natural Gas Act, interstate natural gas companies must charge rates that are just and reasonable. In addition, the NGA prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. On December 21, 2010, an Administrative Law Judge certified a contested offer of settlement relating to FGT's rates and terms and conditions of service. On January 10, 2011, the contesting party withdrew its opposition to the settlement. On February 24, 2011, the FERC issued an order approving the settlement, which order settled a number of issues related to FGT's rates and terms and conditions of service. Among other matters, FGT is required to make its next NGA section 4 general rate case filing no later than November 1, 2014.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2029. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.6 million and $5.5 million for the three months ended

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September 30, 2012 and 2011, respectively. For the nine months ended September 30, 2012 and 2011, rental expense for operating leases totaled approximately $16.8 million and $15.7 million, respectively.

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

Sunoco Litigation

Following the announcement of the Sunoco Merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco Merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco's board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. In September 2012, all of these lawsuits were settled with no payment obligation on the part of any of the defendants following the filing of Current Reports on Form 8-K that included additional disclosures that were incorporated by reference into the proxy statement related to the Sunoco Merger. It is anticipated that the plaintiffs' attorneys will seek compensation for attorneys' fees related to their efforts in obtaining these additional disclosures; we currently are not able to estimate how much these fees will be.

Other Litigation and Contingencies

In November, 2011, a derivative lawsuit captioned W. J. Garrett Trust v. Bill W. Byrne, et al., Cause No. 2011-71702, was filed in the 234th Judicial District Court of Harris County, Texas. The petition stated that it was filed on behalf of ETP. ETP was also named as a nominal defendant. The petition also named as defendants ETP GP, ETP LLC, the Boards of Directors of ETP LLC (collectively with ETP GP, and ETP LLC, the "ETP Defendants"), ETE, and Southern Union. In October 2012, the plaintiff and two new unitholder plaintiffs filed their Third Amended Petition, naming these same defendants and adding Royal Bank of Scotland, PLC, RBS Securities, Inc. ("RBS"), and four members of ETP management ("Management Defendants") as defendants. In their third amended petition, the plaintiffs allege that the ETP Defendants breached their fiduciary and contractual duties in connection with the Citrus Merger and ETP's contribution of its Propane Business to AmeriGas (the "AmeriGas Transaction"). The third amended petition alleges that the Citrus Merger, among other things, involves an unfair price and an unfair process and that the ETP Defendants failed to adequately evaluate the transaction. The third amended petition also alleges that the ETP Defendants failed to, among other things, adequately evaluate the AmeriGas Transaction. The third amended petition alleges that these defendants entered into both transactions primarily to assist in ETE's consummation of its merger with Southern Union and thereby primarily to benefit themselves personally. The third amended petition further alleges that RBS committed malpractice in issuing fairness opinions and that the Management Defendants failed to disclose material information regarding RBS' relationship with ETE. The third amended petition asserts claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and Management Defendants. The third amended petition asserts claims against ETE and Southern Union for aiding and abetting the breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith, as well as tortious interference with contract. The third amended petition also asserts claims for declaratory judgment and conspiracy against all defendants. The lawsuit seeks, among other things, the following relief: (i) a declaration that the lawsuit is properly maintainable as a derivative action; (ii) a declaration that the Citrus Merger and AmeriGas Transaction were unlawful and unenforceable because they involved breaches of fiduciary and contractual duties; (iii) a declaration that ETE and Southern Union aided and abetted the alleged breaches of fiduciary and contractual duties; (iv) a declaration that defendants conspired to breach, aided and abetted, and did breach fiduciary and contractual duties; (v) an order directing the ETP Defendants and Management Defendants to exercise their fiduciary duties to obtain a transaction or transactions in the best interest of ETP's unitholders; (vi) damages; and (vii) attorneys' and other fees and costs.

In March 2012, this action was transferred to the 157th Judicial District Court of Harris County, Texas. In October 2012, the defendants filed a motion for summary judgment; the court has not yet ruled on the motion. Trial in this

action is not currently set.
We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and NGLs are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will

remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated we accrue the contingent obligation as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2011, accruals of approximately $18.2 million were reflected on our balance sheet related to these contingent obligations. As of September 30, 2012 there were no accruals reflected on our balance sheet related to contingent obligations, as all contingent obligations were related to our Propane Business which was contributed to AmeriGas in January 2012 (see Note 6). As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

No amounts have been recorded in our September 30, 2012 or December 31, 2011 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage and to limit the financial liability which could result from such events. However, the risk of environmental or other damage is inherent in transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products, as it is with other entities engaged in similar businesses.

We are unable to estimate any losses or range of losses that could result from such developments. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of September 30, 2012 and December 31, 2011, accruals on an undiscounted basis of $8.6 million and $13.7 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities related to environmental matters.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs. Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by PCBs. The costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through

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2025 is $5.0 million, which is included in the aggregate environmental accruals discussed above. Transwestern received approval from the FERC for the continuation of rate recovery of projected soil and groundwater remediation costs not related to PCBs for the term of its rate case settlement.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

The EPA Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

On August 20, 2010, the EPA published new regulations under the federal CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule’s requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule is required by October 2013.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if equipment is replaced or existing facilities are expanded in the future. At this point, we are not able to predict the cost to comply with the rule’s requirements, because the rule applies only to changes we might make in the future, but we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations.

On April 17, 2012, the EPA issued the final Oil and Natural Gas Sector New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. The standards revise the new source performance standards for volatile organic compounds from leaking components at onshore natural gas processing plants and new source performance standards for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by the existing standards. In addition to the operations covered by the existing standards, the newly established standards regulate volatile organic compound emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels. In general, the revised New Source Performance Standards will apply only to sources that are newly constructed or substantially modified or reconstructed in the future, while the revised National Emission Standards for Hazardous Air Pollutants will not require most sources to which they apply to be in compliance until 2015. ETP is reviewing the new standards to determine the impact on its operations.

Our pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended September 30, 2012 and 2011, $0.8 million and $4.2 million, respectively, of capital costs and $3.9 million and $3.9 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the nine months ended September 30, 2012 and 2011, $5.4 million and $9.7 million, respectively, of capital costs and $9.9 million and $9.8 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing.

Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to

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ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Our operations are also subject to the requirements of the OSHA and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

15. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdrawal of natural gas.

We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

Our trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment's operations and are netted in cost of products sold in our consolidated statements of operations. Additionally, we also have trading activities related to power in our "All Other" segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

Derivatives are utilized in our midstream segment in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. To the extent that financial contracts are not tied to physical delivery volumes, we may engage in offsetting financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

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Prior to the deconsolidation of the Propane Business, we also used propane futures contracts to fix the purchase price related to certain fixed price sales contracts. Prior to the sale of our cylinder exchange business, we used propane futures contracts to secure the purchase price of our propane inventory for a percentage of the anticipated sales.

The following table details our outstanding commodity-related derivatives:

	September 30, 2012		December 31, 2011	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX [1]	(29,850,000)	2012-2013	(151,260,000)	2012-2013
Power (Megawatt):				
Forwards	230,000	2012-2013	—	—
Futures	(14,500)	2012	—	—
Options — Calls	1,535,600	2012-2013	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(8,057,500)	2012-2013	(61,420,000)	2012-2013
Swing Swaps IFERC	(18,827,500)	2012-2013	92,370,000	2012-2013
Fixed Swaps/Futures	(2,992,500)	2012-2014	797,500	2012
Forward Physical Contracts	(7,505,500)	2012-2013	(10,672,028)	2012
Propane (Gallons):				
Forwards/Swaps	—	—	38,766,000	2012-2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(20,670,000)	2012-2013	(28,752,500)	2012
Fixed Swaps/Futures	(46,752,500)	2012-2013	(45,822,500)	2012
Hedged Item — Inventory	46,752,500	2012-2013	45,822,500	2012
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(4,600,000)	2012-2013	—	—
Fixed Swaps/Futures	(11,900,000)	2012-2013	—	—
Options — Puts	900,000	2012	3,600,000	2012
Options — Calls	(900,000)	2012	(3,600,000)	2012

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

We expect gains of $4.1 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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We had the following interest rate swaps outstanding as of September 30, 2012 and December 31, 2011, none of which were designated as hedges for accounting purposes:

Term	Type [1]	Notional Amount Outstanding September 30, 2012	Notional Amount Outstanding December 31, 2011
May 2012[2]	Forward starting to pay a fixed rate of 2.59% and receive a floating rate	$—	$350,000
August 2012[2]	Forward starting to pay a fixed rate of 3.51% and receive a floating rate	—	500,000
July 2013[2]	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	400,000	300,000
July 2014[2]	Forward starting to pay a fixed rate of 4.26% and receive a floating rate	400,000	—
July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600,000	500,000

(1) Floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers and power generation companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets. The Partnership had net deposits with counterparties of $38.0 million and $66.2 million as of September 30, 2012 and December 31, 2011, respectively.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

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Derivative Summary

The following table provides an overview of the Partnership’s derivative assets and liabilities as of September 30, 2012 and December 31, 2011:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$5,529	$77,197	$(16,209)	$(819)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	135,448	227,337	(156,673)	(251,268)
Commodity derivatives	10,895	708	(10,053)	(4,844)
Interest rate derivatives	54,479	36,301	(150,220)	(117,020)
	200,822	264,346	(316,946)	(373,132)
Total derivatives	$206,351	$341,543	$(333,155)	$(373,951)

The commodity derivatives (margin deposits) are recorded in “Other current assets” on our consolidated balance sheets. The remainder of the derivatives are recorded in “Price risk management assets/liabilities.” In addition to the above derivatives, "Price risk management liabilities" as of September 30, 2012 included approximately $6.6 million of option premiums that are being amortized through 2013.

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$(3,430)	$6,127	$10,465	$14,470

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$3,601	$5,116	$13,652	$27,069

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion

		Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$(63)	$(112)	$(17)	$351

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	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$4,230	$(3,559)	$28,887	$18,732

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Derivatives not designated as hedging instruments:					
Commodity derivatives - Trading	Cost of products sold	$4,196	$—	$(7,099)	$—
Commodity derivatives - Non-trading	Cost of products sold	(6,052)	9,175	$(13,567)	$4,174
Interest rate derivatives	Losses on non-hedged interest rate derivatives	(65)	(68,595)	(8,087)	(64,705)
Total		$(1,921)	$(59,420)	$(28,753)	$(60,531)

16. RELATED PARTY TRANSACTIONS:

In the ordinary course of business, we provide Regency with certain natural gas and NGLs sales and transportation services and compression equipment, and Regency provides us with certain contract compression services. In the ordinary course of business, we provide Southern Union with certain natural gas and NGLs sales, and Southern Union provides us with certain natural gas and NGLs sales and transportation services. These related party transactions are generally based on transactions made at market-related rates.

ETE has agreements with subsidiaries to provide or receive various general and administrative services. ETE pays us to provide services on its behalf and the behalf of other subsidiaries of ETE, which includes the reimbursement of various general and administrative services for expenses incurred by us on behalf of Regency. Southern Union also pays us to provide services on its behalf.

The following table summarizes certain related party transactions by counterparty for the three and nine months ended September 30, 2012 and 2011 for our current related parties.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Management Fees Received:				
ETE	$4,425	$4,350	$13,275	$12,729
Southern Union	2,323	N/A [(1)]	3,840	N/A [(1)]
Sales to Related Parties:				
Regency	10,403	6,902	23,884	25,855
Southern Union	8,523	N/A [(1)]	14,514 [(1)]	N/A [(1)]
Purchases from Related Parties:				
Regency	(9,482)	(7,234)	(23,612)	(26,433)

Southern Union	(11,239)	N/A [1]	(19,434) [1]	N/A [1]

[1] Southern Union became a related party on March 26, 2012 as a result of ETE's acquisition of Southern Union. Transactions prior to that date are not reflected.

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Transactions between us and Enterprise were previously considered to be related party transactions due to Enterprise's ownership of a portion of ETE's limited partner interests. During the three and nine months ended September 30, 2011, ETP recorded sales to Enterprise of $164.7 million and $473.0 million, respectively, and purchases from Enterprise of $90.6 million and $350.7 million, respectively, all of which were related party transactions based on Enterprise's interests in ETE at the time of the transactions.

17. OTHER INFORMATION:

The tables below present additional detail for certain balance sheet captions.

Other Current Assets

Other current assets consisted of the following:

	September 30, 2012	December 31, 2011
Deposits paid to vendors	$38,049	$66,231
Prepaid expenses and other	76,275	115,138
Total other current assets	$114,324	$181,369

Other Non-Current Assets, net

Other non-current assets, net consisted of the following:

	September 30, 2012	December 31, 2011
Unamortized financing costs (3 to 30 years)	$56,295	$46,618
Regulatory assets	87,023	88,993
Other	13,811	23,990
Total other non-current assets, net	$157,129	$159,601

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	September 30, 2012	December 31, 2011
Interest payable	$143,728	$142,616
Customer advances and deposits	16,653	84,300
Accrued capital expenditures	378,043	196,789
Accrued wages and benefits	43,720	67,266
Taxes payable other than income taxes	92,950	77,073
Income taxes payable	9,583	14,422
Other	38,458	46,736
Total accrued and other current liabilities	$723,135	$629,202

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18. REPORTABLE SEGMENTS:

Our financial statements reflect five reportable segments, which conduct their business exclusively in the United States of America, as follows:

- intrastate natural gas transportation and storage;
- interstate natural gas transportation;
- midstream;
- NGL transportation and services; and
- retail propane and other retail propane related operations.

Intersegment and intrasegment transactions are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation segment are primarily reflected in gathering transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our retail propane and other retail propane related segment are primarily reflected in retail propane sales and other.

We previously reported segment operating income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior year to be consistent with the current year presentation.

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The following tables present the financial information by segment for the following periods:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues:				
Intrastate natural gas transportation and storage:				
Revenues from external customers	$502,562	$617,244	$1,401,595	$1,849,575
Intersegment revenues	52,281	33,590	129,782	245,512
	554,843	650,834	1,531,377	2,095,087
Interstate natural gas transportation — revenues from external customers	131,989	120,065	387,165	330,016
Midstream:				
Revenues from external customers	549,197	551,393	1,437,487	1,455,017
Intersegment revenues	107,718	78,742	304,754	421,154
	656,915	630,135	1,742,241	1,876,171
NGL transportation and services:				
Revenues from external customers	156,909	131,284	459,028	224,970
Intersegment revenues	11,404	15,312	37,313	20,446
	168,313	146,596	496,341	245,416
Retail propane and other retail propane related — revenues from external customers	—	236,781	92,972	1,037,969
All other:				
Revenues from external customers	79,817	44,696	162,515	96,433
Intersegment revenues	28,277	5,059	65,355	45,958
	108,094	49,755	227,870	142,391
Eliminations	(199,680)	(132,703)	(537,204)	(733,070)
Total revenues	$1,420,474	$1,701,463	$3,940,762	$4,993,980

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	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
Segment Adjusted EBITDA				
Intrastate transportation and storage	$120,593	$170,183	$469,810	$514,547
Interstate transportation	204,488	102,312	501,888	265,920
Midstream	105,252	103,233	298,915	273,829
NGL transportation and services	36,445	30,504	110,623	55,200
Retail propane and other retail propane related	3,977	(3,667)	94,476	150,924
All other	10,910	1,587	8,362	3,167
Total	481,665	404,152	1,484,074	1,263,587
Depreciation and amortization	(94,812)	(106,419)	(282,485)	(294,356)
Interest expense, net of interest capitalized	(112,141)	(124,000)	(383,271)	(347,706)
Gain on deconsolidation of Propane Business	—	—	1,056,709	—
Losses on non-hedged interest rate derivatives	(65)	(68,595)	(8,087)	(64,705)
Non-cash unit-based compensation expense	(9,198)	(10,350)	(30,190)	(31,139)
Unrealized gains (losses) on commodity risk management activities	11,456	(6,441)	(59,519)	1,213
Loss on extinguishment of debt	—	—	(115,023)	—
Adjusted EBITDA attributable to noncontrolling interest	13,188	13,152	44,246	23,737
Adjusted EBITDA attributable to discontinued operations	(4,760)	(5,007)	(15,183)	(15,028)
Adjusted EBITDA attributable to unconsolidated affiliates	(105,359)	(15,229)	(301,559)	(37,623)
Equity in earnings of unconsolidated affiliates	7,920	6,713	63,011	13,386
Other	6,245	(6,344)	8,347	(6,559)
Income from continuing operations before income tax expense	$194,139	$81,632	$1,461,070	$504,807

	September 30, 2012	December 31, 2011
Total assets:		
Intrastate natural gas transportation and storage	$4,672,454	$4,784,630
Interstate natural gas transportation	5,586,652	3,661,098
Midstream	3,246,326	2,665,610
NGL transportation and services	3,451,925	2,360,095
Retail propane and other retail propane related	—	1,783,770
All other	1,340,203	263,413
Total	$18,297,560	$15,518,616

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Tabular dollar amounts are in thousands)

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC on February 22, 2012. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Part II - Item 1A. Risk Factors", included in this report, and in "Part I - Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2011.

References to "we," "us," "our," the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries.

Overview

The activities in which we are engaged and the wholly-owned operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including the following segments:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which conducts business under the assumed name of ETC OLP; and
  - interstate natural gas transportation services through ET Interstate. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry.
- NGL transportation, storage and fractionation services primarily through Lone Star.
- Other operations, including natural gas compression services through ETC Compression.

Previously we conducted our retail propane activities through HOLP and Titan. On January 12, 2012, we contributed HOLP and Titan to AmeriGas, as discussed in Note 5 of the consolidated financial statements included in Item 1.

Recent Developments

Sunoco Merger

On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly-owned subsidiary of ETP, completed its merger with Sunoco, Inc. ("Sunoco"). Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 54,971,724 ETP Common Units and a total of approximately $2.6 billion in cash.

ETP used approximately $2.0 billion of Sunoco's cash on hand to partially fund the cash portion of the Sunoco Merger consideration. The remainder of the cash portion of the merger consideration, approximately $620 million, was funded with borrowings on ETP's Credit Facility.

Sunoco generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States. Prior to October 5, 2012, Sunoco also owned a 2% general partner interest, 100% of the IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. In addition, in September 2012, Sunoco completed its exit from the refining business as a result of the contribution of its Philadelphia refinery to a joint venture and the related sale of its crude oil and refined product inventory to this joint venture. In connection with this transaction, Sunoco received a 33% non-operating minority interest in this joint venture.

Sunoco Logistics is a publicly traded limited partnership that owns and operates a logistics business consisting of a geographically diverse portfolio of complementary pipeline, terminalling and crude oil acquisition and marketing assets. The refined products pipelines business consists of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in refined products pipelines. The crude oil pipeline business consists of crude oil pipelines located principally in Oklahoma and Texas. The terminal facilities business consists of refined products and crude oil terminal capacity at the Nederland Terminal on the Gulf Coast of Texas and capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey. The crude oil acquisition and marketing business, principally conducted in Oklahoma and Texas, involves the acquisition and marketing of crude oil and consists of crude oil transport trucks and crude oil truck unloading facilities.

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Holdco Transaction

Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation ("Holdco"), an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco to Holdco and will retain a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90,706,000 Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units are entitled to 35% of the quarterly cash distribution generated by ETP and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year, which is the current level. Pursuant to a stockholders agreement between ETE and ETP, ETP will control Holdco. Consequently, ETP consolidated Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

Under the terms of the Holdco transaction agreement, ETE will relinquish an aggregate of $210 million of incentive distributions over 12 consecutive quarters following the closing of the Holdco Transaction. The relinquishment will apply to the distribution paid with respect to the third quarter ended September 30, 2012.

Discontinued Operations

In October 2012, we sold ETC Canyon Pipeline, LLC ("Canyon") for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been restated to present Canyon's operations as discontinued operations. Canyon's assets and liabilities have been reclassified and reported as assets and liabilities held for sale as of September 30, 2012. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $145 million during the three months ended September 30, 2012.

General

Our primary objective is to increase the level of our distributable cash flow over time by pursuing a business strategy that is currently focused on growing our natural gas and NGL businesses through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain strategic operations and businesses or assets. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.

Prior to the completion of the Sunoco Merger and Holdco Transaction on October 5, 2012, our principal operations included the following segments:

- Intrastate natural gas transportation and storage – Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that have the greatest impact on our interruptible business are primarily between West Texas and East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold. Conversely, when basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and fuel retention. Excess fuel retained after consumption, if any, is typically sold at market prices. In addition to transport fees, we generate revenue from purchasing natural gas and transporting it across our system. The natural gas is then sold to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System purchases natural gas at the wellhead for transport and selling. Other pipelines with access to West Texas supply, such as Oasis and ET Fuel, may also purchase gas at the wellhead and other supply sources for transport across our system to be sold at market on the east side of our system. This activity allows our intrastate transportation and storage segment to capture the current basis differentials between delivery points on our system or to capture basis differentials that were previously locked in through hedges. Firm capacity long-term contracts are typically not subject to price differentials between shipping locations.

We also generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used to describe a pricing environment when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. Our earnings from natural gas storage we purchase, store and sell are subject to the current market prices (spot price in relation to forward price) at the time the storage gas is hedged. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical

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gas is withdrawn and the related financial derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens prior to withdrawal of the gas, we will record unrealized losses or lower unrealized gains.

As noted above, any excess retained fuel is sold at market prices. To mitigate commodity price exposure, we will use financial derivatives to hedge prices on a portion of natural gas volumes retained. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

In addition, we use financial derivatives to lock in price differentials between market hubs connected to our assets on a portion of our intrastate transportation system's unreserved capacity. Gains and losses on these financial derivatives are dependent on price differentials at market locations, primarily points in West Texas and East Texas. We account for these derivatives using mark-to-market accounting, and the change in the value of these derivatives is recorded in earnings. During the fourth quarter of 2011, we began using derivatives for trading purposes.

- Interstate natural gas transportation – The majority of our interstate transportation revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Shippers on our interstate pipelines pay reservation charges for the firm capacity reserved for their use under multi-year contracts. In addition to reservation revenues, additional revenue sources include interruptible transportation charges as well as usage rates and overrun rates paid by firm shippers based on their actual capacity usage.
- Midstream – Revenue is principally dependent upon the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines as well as the level of natural gas and NGL prices.

In addition to fee-based contracts for gathering, treating and processing, we also have percent of proceeds and keep-whole contracts, which are subject to market pricing. For percent of proceeds contracts, we retain a portion of the natural gas and NGLs processed, or a portion of the proceeds of the sales of those commodities, as a fee. When natural gas and NGL prices increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGLs decrease, so does the value of the portion we retain as a fee. For wellhead (keep-whole) contracts, we retain the difference between the price of NGLs and the cost of the gas to process the NGLs. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could become negative; however, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs in the event it is uneconomical to process this gas. Our processing contracts and wellhead purchases in rich natural gas areas provide that we earn and take title to specified volumes of NGLs, which we also refer to as equity NGLs. Equity NGLs in our midstream segment are derived from performing a service in a percent of proceeds contract or produced under a keep-whole arrangement. In addition to NGL price risk, our processing activity is also subject to price risk from natural gas because, in order to process the gas, in some cases we must purchase it. Therefore, lower gas prices generally result in higher processing margins.

We conduct marketing operations in which we market certain of the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that does not originate from our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices of natural gas, less the costs of transportation.

- NGL transportation and services – NGL transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are based on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery, custody transfer, rail/truck loading and unloading fees. Storage contracts may be for dedicated storage or fungible storage. Dedicated storage enables a customer to reserve an entire storage cavern, which allows the customer to inject and withdraw proprietary and often unique products. Fungible storage allows a customer to store specified quantities of NGL products that are commingled in a storage cavern with other customers' products of the same type and grade. NGL storage contracts may be entered into on a firm or interruptible basis. Under a firm basis contract, the customer obtains the right to store products in the storage caverns throughout the term of the contract; whereas, under an interruptible basis contract, the customer receives only limited assurance regarding the availability of capacity in the storage caverns.

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This segment also includes revenues earned from processing and fractionating refinery off-gas. Under these contracts we receive an O-grade stream from cryogenic processing plants located at refineries and fractionate the products into their pure components. We deliver purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, we have percentage-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percentage-of-proceeds contracts, we retain a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion we retain as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion we retain as a fee. Under our income sharing contracts, we pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and olefins prices increase in relation to natural gas prices, the value of the percent we retain as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent we retain as a fee.

- Retail propane and other retail propane related operations – On January 12, 2012 we contributed our propane operations, excluding our cylinder exchange operations, to AmeriGas (See Note 6 of Item 1). Subsequent to this contribution our retail propane and other retail propane segment includes our investment in AmeriGas as well as our cylinder exchange business. We sold our cylinder exchange business in June 2012.

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Results of Operations

Consolidated Results

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Change	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Change
Segment Adjusted EBITDA						
Intrastate transportation and storage	$120,593	$170,183	$(49,590)	$469,810	$514,547	$(44,737)
Interstate transportation	204,488	102,312	102,176	501,888	265,920	235,968
Midstream	105,252	103,233	2,019	298,915	273,829	25,086
NGL transportation and services	36,445	30,504	5,941	110,623	55,200	55,423
Retail propane and other retail propane related	3,977	(3,667)	7,644	94,476	150,924	(56,448)
All other	10,910	1,587	9,323	8,362	3,167	5,195
Total	481,665	404,152	77,513	1,484,074	1,263,587	220,487
Depreciation and amortization	(94,812)	(106,419)	11,607	(282,485)	(294,356)	11,871
Interest expense, net of interest capitalized	(112,141)	(124,000)	11,859	(383,271)	(347,706)	(35,565)
Gain on deconsolidation of Propane Business	—	—	—	1,056,709	—	1,056,709
Losses on non-hedged interest rate derivatives	(65)	(68,595)	68,530	(8,087)	(64,705)	56,618
Non-cash unit-based compensation expense	(9,198)	(10,350)	1,152	(30,190)	(31,139)	949
Unrealized gains (losses) on commodity risk management activities	11,456	(6,441)	17,897	(59,519)	1,213	(60,732)
Loss on extinguishment of debt	—	—	—	(115,023)	—	(115,023)
Adjusted EBITDA attributable to noncontrolling interest	13,188	13,152	36	44,246	23,737	20,509
Adjusted EBITDA attributable to discontinued operations	(4,760)	(5,007)	247	(15,183)	(15,028)	(155)
Adjusted EBITDA attributable to unconsolidated affiliates	(105,359)	(15,229)	(90,130)	(301,559)	(37,623)	(263,936)
Equity in earnings of unconsolidated affiliates	7,920	6,713	1,207	63,011	13,386	49,625
Other	6,245	(6,344)	12,589	8,347	(6,559)	