Energy Transfer Partners, L.P.
Form 10-Q
May 09, 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 March 31, 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 May 2, 2012, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	229,563,121	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, 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
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
Credit Suisse	Credit Suisse Securities (USA) LLC
DOT	U.S. Department of Transportation
El Paso	El Paso Corporation
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

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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
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
NOAA	National Oceanic and Atmospheric Administration
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
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

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 of our Propane Business 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 the Partnership's 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)

	March 31, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$156,535	$106,816
Marketable securities	11	1,229
Accounts receivable, net of allowance for doubtful accounts of $538 and $7,651 as of March 31, 2012 and December 31, 2011, respectively	476,662	568,579
Accounts receivable from related companies	46,330	81,753
Inventories	193,906	306,740
Exchanges receivable	11,587	18,808
Price risk management assets	25,880	11,429
Other current assets	145,072	180,140
Total current assets	1,055,983	1,275,494
PROPERTY, PLANT AND EQUIPMENT	13,339,883	13,983,888
ACCUMULATED DEPRECIATION	(1,321,339)	(1,677,522)
	12,018,544	12,306,366
ADVANCES TO AND INVESTMENTS IN AFFILIATES	3,350,358	200,612
LONG-TERM PRICE RISK MANAGEMENT ASSETS	22,470	25,537
GOODWILL	614,012	1,219,597
INTANGIBLE ASSETS, net	180,160	331,409
OTHER NON-CURRENT ASSETS, net	166,263	159,601
Total assets	$17,407,790	$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)

	March 31, 2012	December 31, 2011
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$318,823	$401,053
Accounts payable to related companies	4,298	33,373
Exchanges payable	9,040	17,906
Price risk management liabilities	12,375	79,518
Accrued and other current liabilities	504,613	629,202
Current maturities of long-term debt	108,224	424,117
Total current liabilities	957,373	1,585,169
LONG-TERM DEBT, less current maturities	8,741,496	7,388,170
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	88,209	42,303
OTHER NON-CURRENT LIABILITIES	172,979	152,550
COMMITMENTS AND CONTINGENCIES (Note 13)		
EQUITY:		
General Partner	181,649	181,646
Limited Partners:		
Common Unitholders	6,529,759	5,533,492
Accumulated other comprehensive income	23,361	6,569
Total partners’ capital	6,734,769	5,721,707
Noncontrolling interest	712,964	628,717
Total equity	7,447,733	6,350,424
Total liabilities and equity	$17,407,790	$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 March 31, 2012	2011
REVENUES:		
Natural gas sales	$421,416	$599,468
NGL sales	361,577	156,901
Gathering, transportation and other fees	388,744	336,098
Retail propane sales	75,445	528,466
Other	58,678	66,644
Total revenues	1,305,860	1,687,577
COSTS AND EXPENSES:		
Cost of products sold	773,485	994,457
Operating expenses	127,990	188,489
Depreciation and amortization	101,917	95,964
Selling, general and administrative	48,523	45,532
Total costs and expenses	1,051,915	1,324,442
OPERATING INCOME	253,945	363,135
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(136,820)	(107,240)
Equity in earnings of affiliates	54,625	1,633
Gain on deconsolidation of Propane Business	1,055,944	—
Losses on disposal of assets	(1,024)	(1,726)
Loss on extinguishment of debt	(115,023)	—
Gains on non-hedged interest rate derivatives	27,895	1,779
Other, net	678	218
INCOME BEFORE INCOME TAX EXPENSE	1,140,220	257,799
Income tax expense	14,123	10,597
NET INCOME	1,126,097	247,202
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	11,364	—
NET INCOME ATTRIBUTABLE TO PARTNERS	1,114,733	247,202
GENERAL PARTNER’S INTEREST IN NET INCOME	116,537	107,539
LIMITED PARTNERS’ INTEREST IN NET INCOME	$998,196	$139,663
BASIC NET INCOME PER LIMITED PARTNER UNIT	$4.36	$0.71
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	226,549,263	193,821,128
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$4.35	$0.71
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	227,406,484	194,526,600

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 March 31,	
	2012	2011
Net income	$1,126,097	$247,202
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(3,482)	(16,968)
Change in value of derivative instruments accounted for as cash flow hedges	20,388	6,159
Change in value of available-for-sale securities	(114)	608
	16,792	(10,201)
Comprehensive income	1,142,889	237,001
Less: Comprehensive income attributable to noncontrolling interest	11,364	—
Comprehensive income attributable to partners	$1,131,525	$237,001

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 THREE MONTHS ENDED MARCH 31, 2012
(Dollars in thousands)
(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
Balance, December 31, 2011	$181,646	$5,533,492	$ 6,569	$ 628,717	$6,350,424
Distributions to partners	(116,540)	(202,057)	—	—	(318,597)
Distributions to noncontrolling interest	—	—	—	(6,956)	(6,956)
Units issued for cash	—	87,327	—	—	87,327
Capital contributions from noncontrolling interest	—	—	—	79,839	79,839
Units issued in connection with Citrus Merger	—	105,000	—	—	105,000
Distributions on unvested unit awards	—	(2,023)	—	—	(2,023)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	6	10,799	—	—	10,805
Other comprehensive income, net of tax	—	—	16,792	—	16,792
Other, net		(975)	—	—	(975)
Net income	116,537	998,196	—	11,364	1,126,097
Balance, March 31, 2012	$181,649	$6,529,759	$ 23,361	$ 712,964	$7,447,733

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)

	Three Months Ended March 31,	
	2012	2011
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES:		
Net income	$1,126,097	$247,202
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	101,917	95,964
Amortization of finance costs charged to interest	2,984	2,298
Loss on extinguishment of debt	115,023	—
Non-cash compensation expense	10,709	10,189
Gain on deconsolidation of Propane Business	(1,055,944)	—
Losses on disposal of assets	1,024	1,726
Distributions on unvested awards	(2,023)	(1,788)
Distributions in excess of (less than) equity in earnings of affiliates, net	(18,064)	4,687
Other non-cash	7,682	2,142
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation (see Note 3)	(34,406)	(71,833)
Net cash provided by operating activities	254,999	290,587
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for Citrus Merger	(1,895,000)	—
Cash proceeds from contribution of Propane Business	1,383,802	—
Cash paid for all other acquisitions, net of cash received	(10,066)	(3,060)
Capital expenditures (excluding allowance for equity funds used during construction)	(519,042)	(210,955)
Contributions in aid of construction costs	5,732	2,754
Distributions from (advances to) affiliates, net	3,890	(11,053)
Proceeds from the sale of assets	12,845	681
Net cash used in investing activities	(1,017,839)	(221,633)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	2,558,084	917,094
Repayments of long term debt	(1,556,287)	(758,615)
Net proceeds from issuance of Limited Partner units	87,327	57,373
Capital contributions from noncontrolling interest	67,128	—
Distributions to partners	(318,597)	(274,208)
Distributions to noncontrolling interest	(6,956)	—
Debt issuance costs	(18,140)	—
Net cash provided by (used in) financing activities	812,559	(58,356)
INCREASE IN CASH AND CASH EQUIVALENTS	49,719	10,598
CASH AND CASH EQUIVALENTS, beginning of period	106,816	49,540
CASH AND CASH EQUIVALENTS, end of period	$156,535	$60,138

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, Utah, West Virginia and Colorado. 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, North Texas System and Northern Louisiana assets. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance and Uinta Basins of Colorado and Utah, respectively. 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 engaged in interstate transportation of natural gas.
- 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.
- 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 to AmeriGas. See Note 5.

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 Energy Transfer Partners as of March 31, 2012 and for the three months ended March 31, 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 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.

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 Energy Transfer Partners as of March 31, 2012, and the Partnership's results

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of operations and cash flows for the three months ended March 31, 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.

Pending Sunoco Merger

On April 30, 2012, we announced our entry into a definitive merger agreement whereby we will acquire Sunoco Inc.in a common unit and cash transaction valued at $5.3 billion based on our unit closing price on April 27, 2012. Under the terms of the merger agreement, Sunoco shareholders would receive, for each Sunoco common share, either $50.00 in cash, 1.0490 ETP Common Units or a combination of $25.00 in cash and 0.5245 ETP Common Units. The aggregate cash paid and ETP Common Units issued will be capped so that the cash and ETP Common Units will each represent 50% of the aggregate consideration. Upon closing, Sunoco shareholders are expected to own approximately 20% of our outstanding limited partner interests. This transaction is expected to close in the third or fourth quarter of 2012, subject to approval by Sunoco's shareholders and customary regulatory approvals.

In connection with the transaction, ETE has agreed to relinquish their right to approximately $210 million of IDRs from us that ETE would otherwise receive over 12 consecutive quarters following the closing of the transaction.

Sunoco owns the general partner interest of Sunoco Logistics, consisting of a 2% ownership interest and IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. Sunoco also generates cash flow from a portfolio of 4,900 retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States.

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 approximately 2,500 miles of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in four refined products pipelines. The crude oil pipeline business consists of approximately 5,400 miles of crude oil pipelines, located principally in Oklahoma and Texas. The terminal facilities business consists of approximately 42 million shell barrels of refined products and crude oil terminal capacity (including approximately 22 million shell barrels of capacity at the Nederland Terminal on the Gulf Coast of Texas and approximately 5 million shell barrels of capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey). The crude oil acquisition and marketing business involves the acquisition and marketing of crude oil and is principally conducted in Oklahoma and Texas and consists of approximately 190 crude oil transport trucks and approximately 120 crude oil truck unloading facilities.

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 results could differ from those estimates.

3. 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.

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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:

	Three Months Ended March 31,	
	2012	2011
Accounts receivable	$(35,024)	$10,469
Accounts receivable from related companies	(57,282)	(24,685)
Inventories	23,050	65,950
Exchanges receivable	7,222	5,330
Other current assets	54,503	(34,575)
Other non-current assets, net	2,447	2,353
Accounts payable	(15,352)	(35,787)
Accounts payable to related companies	75,619	(6,094)
Exchanges payable	(8,865)	4,846
Accrued and other current liabilities	(65,749)	(55,534)
Other non-current liabilities	(5,911)	2,335
Price risk management assets and liabilities, net	(9,064)	(6,441)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation	$(34,406)	$(71,833)

Non-cash investing and financing activities are as follows:

	Three Months Ended March 31,	
	2012	2011
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$201,845	$90,846
AmeriGas limited partner interests received in exchange for contribution of Propane Business (See Note 5)	$1,123,003	$—
NON-CASH FINANCING ACTIVITIES:		
Issuance of common units in connection with Citrus Merger	$105,000	$—

4. INVENTORIES:

Inventories consisted of the following:

	March 31, 2012	December 31, 2011
Natural gas and NGLs, excluding propane	$125,054	$144,251
Propane	2,895	86,958
Appliances, parts and fittings and other	65,957	75,531
Total inventories	$193,906	$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.

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5. INVESTMENTS IN 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 owns a 50% interest in Citrus Corp. ("Citrus"), merged with a subsidiary of ETP and, in connection therewith, ETP paid $1.9 billion in cash and issued $105 million of ETP Common Units (the "Citrus Merger"). 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 El Paso.

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. AmeriGas assumed approximately $71.0 million of existing HOLP debt. We recognized a gain on deconsolidation of $1.06 billion and recorded $39.4 million of equity in earnings related to AmeriGas for the three months ended March 31, 2012. The cash proceeds were used to complete our tender offer of existing debt (see Note 9) in January 2012 and to repay borrowings on our revolving credit facility.

Our investment in AmeriGas reflected $639.6 million in excess of our proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $177.3 million is being amortized over a weighted average period of 12 years, and $462.3 million is being treated as equity method goodwill and non-amortizable intangible assets.

In connection with the closing of this transaction, we entered into a support agreement with AmeriGas (See Note 13). 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 we will have a continuing involvement in this business as a result of our investment in AmeriGas.

6. GOODWILL AND INTANGIBLE ASSETS:

A net decrease in goodwill of $605.6 million was recorded during the three months ended March 31, 2012 due to the contribution of HOLP and Titan to AmeriGas. See Note 5.

Components and useful lives of intangible assets were as follows:

	March 31, 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)	$231,308	$(54,413)	$338,424	$(95,239)
Noncompete agreements (3 to 15 years)	742	(297)	15,431	(7,835)
Patents (9 years)	750	(222)	750	(201)
Other (10 to 15 years)	843	(117)	1,320	(580)
Total amortizable intangible assets	233,643	(55,049)	355,925	(103,855)
Non-amortizable intangible assets:				
Trademarks	1,566	—	79,339	—
Total intangible assets	$235,209	$(55,049)	$435,264	$(103,855)

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Aggregate amortization expense of intangible assets was as follows:

	Three Months Ended March 31,	
	2012	2011
Reported in depreciation and amortization	$4,408	$5,051

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

2012 (remainder)	$11,590
2013	11,694
2014	10,569
2015	10,569
2016	10,569

7. 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 since we use a LIBOR curve 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 March 31, 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 and carrying amount of our consolidated debt obligations at March 31, 2012 was $9.72 billion and $8.85 billion, respectively. As of December 31, 2011, the aggregate fair value and carrying amount of our consolidated debt obligations was $8.39 billion and $7.81 billion, respectively. We consider the fair value of our consolidated debt obligations as 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 March 31, 2012 and December 31, 2011 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at March 31, 2012 Level 1	Level 2
Assets:			
Marketable securities	$11	$11	$—
Interest rate derivatives	33,998	—	33,998
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	47,657	47,657	—
Swing Swaps IFERC	19,093	2,856	16,237
Fixed Swaps/Futures	170,565	170,565	—
Options — Puts	6,765	—	6,765
Forward Physical Swaps	3,367	—	3,367
Power:			
Forwards	11,562	364	11,198
Options — Puts	85	85	—
Options — Calls	107	107	—
Total commodity derivatives	259,201	221,634	37,567
Total Assets	$293,210	$221,645	$71,565
Liabilities:			
Interest rate derivatives	$(88,092)	$—	$(88,092)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(73,305)	(73,305)	—
Swing Swaps IFERC	(20,646)	(5,024)	(15,622)
Fixed Swaps/Futures	(116,877)	(116,877)	—
Options — Calls	(2)	—	(2)
Forward Physical Swaps	(918)	—	(918)
Propane — Forwards/Swaps	(879)	—	(879)
Power:			
Forwards	(11,152)	(383)	(10,769)
Options — Calls	(40)	(40)	—
Total commodity derivatives	(223,819)	(195,629)	(28,190)
Total Liabilities	$(311,911)	$(195,629)	$(116,282)

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	Fair Value Total	Fair Value Measurements at December 31, 2011	
		Level 1	Level 2
Assets:			
Marketable securities	$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 Swaps	699	—	699
Propane – Forwards/Swaps	9	—	9
Total commodity derivatives	299,641	279,183	20,458
Total Assets	$337,171	$280,412	$56,759
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 Swaps	(712)	—	(712)
Propane – Forwards/Swaps	(4,131)	—	(4,131)
Total commodity derivatives	(251,330)	(233,462)	(17,868)
Total Liabilities	$(368,350)	$(233,462)	$(134,888)

8. NET INCOME PER LIMITED PARTNER UNIT:

Our net income for partners' capital and statement 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.

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

	Three Months Ended March 31,	
	2012	2011
Net income attributable to partners	$1,114,733	$247,202
General Partner's interest in net income	116,537	107,539
Limited Partners' interest in net income	998,196	139,663
Additional (losses) earnings allocated from General Partner	(147)	348
Distributions on employee unit awards, net of allocation to General Partner	(9,754)	(1,776)
Net income available to Limited Partners	$988,295	$138,235
Weighted average Limited Partner units — basic	226,549,263	193,821,128
Basic net income per Limited Partner unit	$4.36	$0.71
Weighted average Limited Partner units	226,549,263	193,821,128
Dilutive effect of unvested Unit Awards	857,221	705,472
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	227,406,484	194,526,600
Diluted net income per Limited Partner unit	$4.35	$0.71

9. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	March 31, 2012	December 31, 2011
ETP Senior Notes	$7,800,000	$6,550,000
Transwestern Senior Notes	870,000	870,000
HOLP Senior Notes	—	71,314
ETP Revolving Credit Facility	190,000	314,438
Other long-term debt	616	10,345
Unamortized discounts	(21,140)	(15,457)
Fair value adjustments related to interest rate swaps	10,244	11,647
Total debt	8,849,720	7,812,287
Less: current maturities	(108,224)	(424,117)
Long-term debt, less current maturities	$8,741,496	$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 $10.9 million in unamortized discounts and fair value adjustments related to interest rate swaps:

2012 (remainder)	$108,224
2013	350,105
2014	380,055
2015	750,112
2016	315,116
Thereafter	6,957,004
Total	$8,860,616

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Senior Notes

In January 2012, we completed a public offering of $1 billion aggregate principal amount of 5.20% Senior Notes due February 1, 2022 and $1 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 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 Any and All Offer and Maximum Tender Offer for a total cost of $885.9 million and a loss on extinguishment of debt of $115.0 million was recorded during the three months ended March 31, 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 on January 19, 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.

Revolving Credit Facility

The indebtedness under ETP’s revolving 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.

As of March 31, 2012, we had $190.0 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $2.28 billion after taking into account letters of credit of $28.3 million. The weighted average interest rate on the total amount outstanding as of March 31, 2012 was 1.74%.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements at March 31, 2012.

10. EQUITY:

Common Units Issued

The change in Common Units during the three months ended March 31, 2012 was as follows:

	Number of Units
Outstanding at December 31, 2011	225,468,108
Common Units issued in connection with the Equity Distribution Agreement	1,600,483
Common Units issued in connection with the Distribution Reinvestment Plan	238,314
Common Units issued in connection with the Citrus Merger	2,249,092
Common Units issued under equity incentive plans	7,124
Outstanding at March 31, 2012	229,563,121

During the three months ended March 31, 2012, we received proceeds from units issued pursuant to an Equity Distribution Agreement with Credit Suisse of $76.7 million, net of commissions, which proceeds were used for general partnership purposes. As of March 31, 2012, no Common Units remain available to be issued under this agreement.

In addition to the Equity Distribution Agreement, we 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 three months ended March 31, 2012, distributions of approximately $10.6

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million were reinvested under the DRIP resulting in the issuance of 238,314 Common Units. As of March 31, 2012, a total of 5,158,007 Common Units remain available to be issued under this agreement.

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

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to approximately $220 million of the IDR's from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters.

AOCI

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

	March 31, 2012	December 31, 2011
Net gains on commodity related hedges	$23,361	$6,455
Unrealized gains on available-for-sale securities	—	114
Total AOCI, net of tax	$23,361	$6,569

11. UNIT-BASED COMPENSATION PLANS:

During the three months ended March 31, 2012, employees were granted a total of 14,917 unvested awards with five-year service vesting requirements, and directors were granted a total of 2,120 unvested awards with three-year service vesting requirements. The weighted average grant-date fair value of these awards was $46.30 per unit. As of March 31, 2012 a total of 2,377,124 unit awards remain unvested, including the new awards granted during the period. We expect to recognize a total of $70.1 million in compensation expense over a weighted average period of 1.8 years related to unvested awards.

12. INCOME TAXES:

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Current expense (benefit):		
Federal	$(193)	$5,028
State	3,672	3,934
Total	3,479	8,962
Deferred expense:		
Federal	3,103	1,019
State	7,541	616
Total	10,644	1,635
Total income tax expense	$14,123	$10,597

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level.

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

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Phase VIII Expansion. Florida Gas' Phase VIII Expansion project was placed in-service on April 1, 2011, at an approximate cost of $2.5 billion, including capitalized equity and debt costs. To date, Florida Gas has entered into long-term firm transportation service agreements with shippers for 25-year terms accounting for approximately 74% of the available expansion capacity.

In 2011, CrossCountry Citrus, LLC (CrossCountry Citrus) and Citrus' other stockholder each made sponsor contributions of $37 million in the form of loans to Citrus, net of repayments. The contributions are related to the costs of Florida Gas' Phase VIII Expansion project. In conjunction with anticipated sponsor contributions, Citrus has entered into a promissory note in favor of each stockholder for up to $150 million. The promissory notes have a final maturity date of March 31, 2014, with no principal payments required prior to the maturity date, and bear an interest rate equal to a one-month Eurodollar rate plus a credit spread of 1.5%. Amounts may be redrawn periodically under the notes to temporarily fund capital expenditures, debt retirements, or other working capital needs.

Florida Gas Pipeline Relocation Costs. The FDOT/FTE has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of Florida Gas' 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 Florida Gas $82.7 million and rejected all damage claims by the FDOT/FTE. On May 2, 2011, the judge issued an order entitling Florida Gas to an easement of 15 feet on either side of its pipelines and 75 feet of temporary work space. The judge further ruled that Florida Gas is entitled to approximately $8 million in interest. In addition to ruling on other aspects of the easement, he ruled that pavement could not be placed directly over Florida Gas' pipeline without the consent of Florida Gas although Florida Gas would be required to relocate the pipeline if it did not provide such consent. He also denied all other pending post-trial motions. The FDOT/FTE filed a notice of appeal on July 12, 2011. Briefing to the Florida Fourth District Court of Appeals (4th DCA) is complete. The 4th DCA granted a request by the FDOT to expedite the appeal. Oral argument was held March 7, 2012. Amounts ultimately received would primarily reduce Florida Gas' property, plant and equipment costs.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Transaction described in Note 5, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550 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 Propane Transaction, 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, FERC certified a contested offer of 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 $5.9 million and $5.0 million for the three months ended March 31, 2012 and 2011, respectively.

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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.

Litigation and Contingencies

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 March 31, 2012 and December 31, 2011, accruals of approximately \$0.1 million and \$18.2 million, respectively, were reflected on our balance sheets related to these contingent obligations. The decrease in the accrual for the three months ended March 31, 2012 is a result of the contribution of our Propane Business to AmeriGas as discussed in Note 5. 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 March 31, 2012 or December 31, 2011 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

CrossCountry, the Southern Union subsidiary that indirectly owns a 50% interest in Citrus, filed a petition in the Delaware Court of Chancery seeking a declaratory judgment against El Paso, the owner of the other 50% interest of Citrus, that the Citrus Merger did not breach El Paso's rights under a joint venture agreement related to Citrus. This petition was filed by CrossCountry following an exchange of letters between CrossCountry, El Paso and Southern Union in which El Paso stated that it believed the Citrus Merger violated the provisions of the joint venture agreement. Subsequently, El Paso filed a petition asserting a counterclaim action against CrossCountry, ETP and ETE based on its claim that the Citrus Merger violated El Paso's right of first refusal and, in such petition, El Paso sought a rescission of the Citrus Merger or, alternatively, damages.

On April 18, 2012, the parties to the declaratory judgment action and related counterclaim action entered into a joint stipulation pursuant to which El Paso agreed that the Citrus Merger did not breach the joint venture agreement and that El Paso was not entitled to rescission or damages with respect to the Citrus Merger. On April 20, 2012, the Delaware court granted an order approving the joint stipulation and, as a result, all litigation regarding El Paso's claims with respect to the Citrus Merger has been terminated.

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,

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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 March 31, 2012 and December 31, 2011, accruals on an undiscounted basis of $11.4 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 2025 is $5.8 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.

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 March 31, 2012 and 2011, $2.1 million and $1.7 million, respectively, of capital costs and $1.5 million and $2.1 million 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 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.

14. 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.

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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.

We use propane futures contracts to secure the purchase price of our propane inventory for a percentage of the anticipated sales by our cylinder exchange business. 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.

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The following table details our outstanding commodity-related derivatives:

	March 31, 2012		December 31, 2011	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX (1)	11,280,000	2012-2013	(151,260,000)	2012-2013
Power (Thousand Megawatt):				
Forwards	(1,000)	2012-2013	—	—
Options — Puts	32	2012	—	—
Options — Calls	84	2012	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(43,882,500)	2012-2013	(61,420,000)	2012-2013
Swing Swaps IFERC	(62,117,500)	2012-2013	92,370,000	2012-2013
Fixed Swaps/Futures	(2,042,500)	2012-2013	797,500	2012
Forward Physical Contracts	(43,604,214)	2012	(10,672,028)	2012
Propane (Gallons):				
Forwards/Swaps	6,571,500	2012-2013	38,766,000	2012-2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(25,920,000)	2012-2013	(28,752,500)	2012
Fixed Swaps/Futures	(55,690,000)	2012-2013	(45,822,500)	2012
Hedged Item — Inventory	55,690,000	2012	45,822,500	2012
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(17,400,000)	2012-2013	—	—
Fixed Swaps/Futures	(35,650,000)	2012-2013	—	—
Options — Puts	2,700,000	2012	3,600,000	2012
Options — Calls	(2,700,000)	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 $19.9 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. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage our current 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 March 31, 2012 and December 31, 2011, none of which were designated as hedges for accounting purposes:

Term	Type [1]	Notional Amount Outstanding March 31, 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 $62.0 million and $66.2 million as of March 31, 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 a balance sheet overview of the Partnership's derivative assets and liabilities as of March 31, 2012 and December 31, 2011:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	March 31, 2012	December 31, 2011	March 31, 2012	December 31, 2011
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$58,103	$77,197	$(486)	$(819)
	58,103	77,197	(486)	(819)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	187,403	227,337	(211,638)	(251,268)
Commodity derivatives	14,565	708	(12,565)	(4,844)
Interest rate derivatives	33,998	36,301	(88,092)	(117,020)
	235,966	264,346	(312,295)	(373,132)
Total derivatives	$294,069	$341,543	$(312,781)	$(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."

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 March 31,	
	2012	2011
Derivatives in cash flow hedging relationships:		
Commodity derivatives	$ 20,429	$ 6,104
Total	$ 20,429	$ 6,104

	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 March 31,	
		2012	2011
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$3,435	$16,968
Total		$3,435	$16,968

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	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion	
		Three Months Ended March 31,	
		2012	2011
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$47	$5
Total		$47	$5

	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 March 31,	
		2012	2011
Derivatives in fair value hedging relationships (including hedged item):			
Commodity derivatives	Cost of products sold	$(9,173)	$6,417
Total		$(9,173)	$6,417

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2012	2011
Derivatives not designated as hedging instruments:			
Commodity derivatives - Trading	Cost of products sold	$(10,586)	$—
Commodity derivatives - Non-trading	Cost of products sold	(2,944)	6,379
Interest rate derivatives	Gains on non-hedged interest rate derivatives	27,895	1,779
Total		$14,365	$8,158

We recognized $17.9 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended March 31, 2011. For the three months ended March 31, 2012 and 2011 we recognized unrealized losses of $86.2 million and $8.9 million, respectively, on commodity derivatives and related hedged inventory accounted for as fair value hedges.

15. RELATED PARTY TRANSACTIONS:

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. For the three months ended March 31, 2012, we recorded revenues of $8.1 million, cost of products sold of $6.1 million and operating expenses of $0.1 million related to transactions with Regency. For the three months ended March 31, 2011, we recorded revenues of $11.5 million, cost of products sold of $11.0 million and operating expenses of $1.5 million related to transactions with Regency.

We received $4.4 million and $4.9 million in management fees from ETE for the provision of various general and administrative services for ETE's benefit for the three months ended March 31, 2012 and 2011, respectively. These management fees include the provision of various general and administrative services for Regency. For the three months ended March 31, 2012 and 2011, we recorded from Regency $1.8 million and $2.3 million, respectively, for reimbursement of various general and administrative expenses incurred by us.

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16. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	March 31, 2012	December 31, 2011
Deposits paid to vendors	$62,043	$66,231
Prepaid expenses and other	83,029	113,909
Total other current assets	$145,072	$180,140

Other Non-Current Assets, net

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

	March 31, 2012	December 31, 2011
Unamortized financing costs (3 to 30 years)	$61,866	$46,618
Regulatory assets	88,214	88,993
Other	16,183	23,990
Total other non-current assets, net	$166,263	$159,601

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	March 31, 2012	December 31, 2011
Interest payable	$149,004	$142,616
Customer advances and deposits	5,006	84,300
Accrued capital expenditures	199,937	196,789
Accrued wages and benefits	25,156	67,266
Taxes payable other than income taxes	53,082	77,073
Income taxes payable	17,068	14,422
Other	55,360	46,736
Total accrued and other current liabilities	$504,613	$629,202

17. 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.

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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, 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.

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

	Three Months Ended March 31, 2012	2011
Revenues:		
Intrastate natural gas transportation and storage:		
Revenues from external customers	$446,796	$588,678
Intersegment revenues	35,257	183,081
	482,053	771,759
Interstate natural gas transportation — revenues from external customers	128,276	105,101
Midstream:		
Revenues from external customers	454,099	413,195
Intersegment revenues	100,459	238,061
	554,558	651,256
NGL transportation and services:		
Revenues from external customers	154,268	—
Intersegment revenues	13,283	—
	167,551	—
Retail propane and other retail propane related — revenues from external customers	80,006	557,215
All other:		
Revenues from external customers	42,415	23,388
Intersegment revenues	8,157	14,427
	50,572	37,815
Eliminations	(157,156)	(435,569)
Total revenues	$1,305,860	$1,687,577

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	Three Months Ended March 31, 2012	2011
Segment Adjusted EBITDA		
Intrastate transportation and storage	$192,269	$172,815
Interstate transportation	112,980	80,110
Midstream	100,288	75,376
NGL transportation and services	35,217	—
Retail propane and other retail propane related	88,795	142,355
All other	6,513	643
Total Segment Adjusted EBITDA	536,062	471,299
Depreciation and amortization	(101,917)	(95,964)
Interest expense, net of interest capitalized	(136,820)	(107,240)
Gain on deconsolidation of Propane Business	1,055,944	—
Gains on non-hedged interest rate derivatives	27,895	1,779
Income tax expense	(14,123)	(10,597)
Non-cash unit-based compensation expense	(10,709)	(10,189)
Unrealized (losses) gains on commodity risk management activities	(85,626)	7,092
Losses on disposal of assets	(1,024)	(1,726)
Loss on extinguishment of debt	(115,023)	—
Adjusted EBITDA attributable to noncontrolling interest	15,247	—
Proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on extinguishment of debt and taxes	(44,487)	(7,470)
Other, net	678	218
Net income	$1,126,097	$247,202

	March 31, 2012	December 31, 2011
Total assets:		
Intrastate natural gas transportation and storage	$4,743,531	$4,784,630
Interstate natural gas transportation	5,630,371	3,661,098
Midstream	2,783,202	2,665,610
NGL transportation and services	2,750,615	2,360,095
Retail propane and other retail propane related	1,230,683	1,783,770
All other	269,388	263,413
Total	$17,407,790	$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 "Item 1A. Risk Factors" included in this report, in 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

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. AmeriGas also assumed approximately $71.0 million of existing HOLP debt. The cash proceeds were used to complete our tender offer in January 2012 and also to pay down borrowings on our revolving credit facility.

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, a subsidiary of Southern Union that indirectly owns a 50% interest in Citrus Corp., merged with a subsidiary of ours and, in connection therewith, ETP paid $1.9 billion in cash and issued $105 million of ETP Common Units (the "Citrus Merger"). As a result of the consummation of the Citrus Merger, ETP owns CrossCountry Energy, LLC ("CrossCountry") which in turn owns a 50% interest in Citrus Corp. The other 50% interest in Citrus Corp. is owned by El Paso. Citrus Corp. owns 100% of FGT, an approximately 5,400 mile natural gas pipeline system that originates in Texas and has the capacity to deliver 3.1 Bcf/d of natural gas to the Florida peninsula.

Expansion of Rich Eagle Ford Mainline

In February 2012, we announced our entry into multiple long-term, fee-based agreements with producers to provide natural gas gathering, processing, and liquids services from the Eagle Ford Shale in south Texas. To facilitate the agreements, we will further expand the REM pipeline and construct a new processing facility. The pipeline expansion announced in February 2012 is expected to be completed in the fourth quarter of 2013, and the processing facility announced in February 2012 is expected to be completed in the fourth quarter of 2012.

Second Fractionator at Lone Star's Mont Belvieu Fractionation Facility

In February 2012, Lone Star announced the construction of a second 100,000 Bbls/d fractionation facility at Mont Belvieu, Texas. Supported by multiple long-term contracts, the second fractionator is necessary to handle the increasing NGL barrels delivered via the partnership's Woodford Shale, Eagle Ford Shale and Permian Basin infrastructure, including Lone Star's 570-mile West Texas Gateway NGL Pipeline. This second fractionation facility is expected to be completed in the first quarter of 2014.

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Pending Sunoco Merger

On April 30, 2012, we announced our entry into a definitive merger agreement whereby we will acquire Sunoco Inc.in a common unit and cash transaction valued at $5.3 billion based on our unit closing price on April 27, 2012. Under the terms of the merger agreement, Sunoco shareholders would receive, for each Sunoco common share, either $50.00 in cash, 1.0490 ETP Common Units or a combination of $25.00 in cash and 0.5245 ETP Common Units. The aggregate cash paid and ETP Common Units issued will be capped so that the cash and ETP Common Units will each represent 50% of the aggregate consideration. Upon closing, Sunoco shareholders are expected to own approximately 20% of our outstanding limited partner interests. This transaction is expected to close in the third or fourth quarter of 2012, subject to approval of Sunoco's shareholders and customary regulatory approvals.

In connection with the transaction, ETE has agreed to relinquish their right to approximately $210 million of IDRs from us that ETE would otherwise receive over 12 consecutive quarters following the closing of the transaction.

Sunoco owns the general partner interest of Sunoco Logistics, consisting of a 2% ownership interest and IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. Sunoco also generates cash flow from a portfolio of 4,900 retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States.

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 approximately 2,500 miles of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in four refined products pipelines. The crude oil pipeline business consists of approximately 5,400 miles of crude oil pipelines, located principally in Oklahoma and Texas. The terminal facilities business consists of approximately 42 million shell barrels of refined products and crude oil terminal capacity (including approximately 22 million shell barrels of capacity at the Nederland Terminal on the Gulf Coast of Texas and approximately 5 million shell barrels of capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey). The crude oil acquisition and marketing business involves the acquisition and marketing of crude oil and is principally conducted in Oklahoma and Texas and consists of approximately 190 crude oil transport trucks and approximately 120 crude oil truck unloading facilities.

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.

Our principal operations include 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 primarily impact our interruptible business are primarily among receipt points between West Texas to 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

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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 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. Tiger, FEP and Transwestern expansion shippers have made 10- to 15-year commitments to pay reservation charges for the firm capacity reserved for their use. 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

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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.

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 5 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.

Revenue from our Propane Business was primarily generated from the sale of propane and propane-related products and services. Subsequent to the contribution of the Propane Business to AmeriGas, our results now reflect the impact of recording our investment in AmeriGas under the equity method. Because AmeriGas's operations are similar to the Propane Business which we contributed, the equity in AmeriGas's earnings that we record is impacted by many of the same factors that we previously experienced with our Propane Business prior to the contribution transaction. Such factors include sensitivity to changes in wholesale propane prices, seasonality, and dependence upon weather conditions.

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Results of Operations

Consolidated Results

	Three Months Ended March 31,		
	2012	2011	Change
Segment Adjusted EBITDA			
Intrastate transportation and storage	$192,269	$172,815	$19,454
Interstate transportation	112,980	80,110	32,870
Midstream	100,288	75,376	24,912
NGL transportation and services	35,217	—	35,217
Retail propane and other retail propane related	88,795	142,355	(53,560)
All other	6,513	643	5,870
Total Segment Adjusted EBITDA	536,062	471,299	64,763
Depreciation and amortization	(101,917)	(95,964)	(5,953)
Interest expense, net of interest capitalized	(136,820)	(107,240)	(29,580)
Gain on deconsolidation of Propane Business	1,055,944	—	1,055,944
Gains on non-hedged interest rate derivatives	27,895	1,779	26,116
Income tax expense	(14,123)	(10,597)	(3,526)
Non-cash unit-based compensation expense	(10,709)	(10,189)	(520)
Unrealized (losses) gains on commodity risk management activities	(85,626)	7,092	(92,718)
Losses on disposal of assets	(1,024)	(1,726)	702
Loss on extinguishment of debt	(115,023)	—	(115,023)
Adjusted EBITDA attributable to noncontrolling interest	15,247	—	15,247
Proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	(44,487)	(7,470)	(37,017)
Other, net	678	218	460
Net income	$1,126,097	$247,202	$878,895

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization increased primarily due to recent acquisitions and assets placed in service partially offset by a decrease as a result of the contribution of the Propane Business in January 2012.

Interest Expense. Interest expense increased principally due to the issuance of $1.5 billion of senior notes in May 2011 to fund the LDH acquisition and the issuance of $2 billion of senior notes in January 2012 to fund the Citrus acquisition. While our interest expense increased as a result of the overall increase in the amount of long-term debt outstanding, the incremental interest from the new senior notes was partially offset by a reduction of several series of our comparatively higher coupon notes which were repurchased in the tender offers that were completed in January 2012.

Gain on Deconsolidation of Propane Business. A gain on deconsolidation was recognized as a result of the contribution of our Propane Business to AmeriGas during the three months ended March 31, 2012.

Gains on Non-Hedged Interest Rate Derivatives. The three months ended March 31, 2012 reflected gains on non-hedged interest rate swaps for which we had total notional amounts outstanding of $1.4 billion as of March 31, 2012, including $800 million of forward-starting floating-to-fixed swaps used to hedge interest rates and $600 million of fixed-to-floating swaps used to swap a portion of our fixed rate debt to floating. During the first quarter of 2012, forward rates increased which resulted in unrealized non-cash gains on our forward-starting floating-to-fixed swaps.

Income Tax Expense. The increase in income tax expense between the periods was primarily due to changes in taxable income within our subsidiaries that are taxable corporations and deferred tax expense related to the deconsolidation of our Propane Business.

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Unrealized (Losses) Gains on Commodity Risk Management Activities. See discussion of the unrealized (losses) gains on commodity risk management activities included in the discussion of segment results below.
Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized in connection with our tender offers in which we repurchased approximately $750 million in aggregate principal amount of Senior Notes in January 2012.
Adjusted EBITDA Attributable to Noncontrolling Interest. The amount reflected for 2012 represents the proportionate share of Lone Star's Adjusted EBITDA attributable to Regency's 30% interest in Lone Star. This amount was excluded from the measure of Segment Adjusted EBITDA. Net income includes the results attributable to Lone Star on a consolidated basis.
Proportionate Share of Unconsolidated Affiliates' Interest, Depreciation, Amortization, Non-cash Compensation Expense, Loss on Debt Extinguishment and Taxes. Amounts reflected for 2012 primarily include our proportionate share of such amounts related to AmeriGas, Citrus and FEP. The 2011 amounts primarily represented our proportionate share of such amounts for FEP only. Such amounts were included in calculating Segment Adjusted EBITDA and net income.
Segment Operating Results
Our reportable segments are discussed below. "All other" includes our compression and wholesale propane businesses. We evaluate segment performance based on Segment Adjusted EBITDA, which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments. The tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

- Gross margin, operating expenses, and selling, general and administrative. These line items are the amounts included in our consolidated financial statements that are attributable to each segment.

- Unrealized gains or losses on commodity risk management activities. These are the unrealized amounts that are included in cost of products sold to calculate gross margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.

- Non-cash compensation expense. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.

- Adjusted EBITDA related to unconsolidated affiliates. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA above.

- Adjusted EBITDA attributable to noncontrolling interest. These amounts represent the portion of Segment Adjusted EBITDA attributable to noncontrolling interest. Currently, the only noncontrolling interest reflected is the 30% interest in Lone Star that is held by Regency. We reflect this amount as noncontrolling interest because we consolidate 100% of Lone Star on our consolidated financial statements.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for year ended December 31, 2011 filed with the SEC on February 22, 2012.
Selling, General and Administrative Expenses Not Allocated to Segments. Selling, general and administrative expenses are allocated monthly to the Operating Companies using the Modified Massachusetts Formula Calculation ("MMFC"). The expenses subject to allocation are based on estimated amounts and take into consideration our actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month which results in over or under allocation of these costs due to timing differences.

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Intrastate Transportation and Storage

	Three Months Ended March 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d)	10,114,354	11,890,824	(1,776,470)
Revenues	$482,053	$771,759	$(289,706)
Cost of products sold	314,171	532,630	(218,459)
Gross margin	167,882	239,129	(71,247)
Unrealized losses (gains) on commodity risk management activities	81,687	(6,831)	88,518
Operating expenses, excluding non-cash compensation expense	(38,903)	(45,799)	6,896
Selling, general and administrative, excluding non-cash compensation expense	(18,802)	(14,500)	(4,302)
Adjusted EBITDA related to unconsolidated affiliates	405	816	(411)
Segment Adjusted EBITDA	$192,269	$172,815	$19,454

Volumes. We experienced a decrease in transported volumes due to an unfavorable natural gas price environment. Although the basis differential between the West and East Texas market hubs remained consistent between the periods, the average spot price at Houston Ship Channel declined to $2.41/MMBtu during the three months ended March 31, 2012 compared to $4.11/MMBtu during the three months ended March 31, 2011.

Segment Adjusted EBITDA. Segment Adjusted EBITDA for the intrastate transportation and storage segment increased primarily due to $60.7 million in realized gains including the settlement of financial derivatives used to hedge natural gas stored in our storage facility that was not withdrawn due to the warmer than normal winter experienced during the three months ended March 31, 2012. The gains were offset by lower retained fuel revenues and unfavorable variances in our natural gas sales.

The components of our intrastate transportation and storage segment gross margin were as follows:

	Three Months Ended March 31,		
	2012	2011	Change
Transportation fees	$143,849	$142,666	$1,183
Natural gas sales and other	13,814	45,199	(31,385)
Retained fuel revenues	16,972	34,982	(18,010)
Storage margin, including fees	(6,753)	16,282	(23,035)
Total gross margin	$167,882	$239,129	$(71,247)

Intrastate transportation and storage gross margin decreased primarily due to the following factors:

- Additional demand-based contracts offset the impact of lower transported volumes, resulting in a net increase of $1.2 million in transportation fees.
- Margin from sales of natural gas and other activities decreased $31.4 million primarily due to unfavorable mark-to-market impacts from system optimization activities of $22.3 million and a decline of $6.7 million in margin where we utilize third party processing.

The margin from the natural gas sales and other includes purchased natural gas for transportation and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. During the first quarter of 2012, our trading activities included the use of financial commodity derivatives. Excluding derivatives related to storage, unrealized losses of $6.0 million were recorded during the three months ended March 31, 2012 compared to unrealized gains of $16.3 million during the three months ended March 31, 2011.

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- Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue decreased $18.0 million primarily due to lower retained volumes of 726,000 MMBtu and a decrease in natural gas prices. Spot prices at Houston Ship Channel averaged $2.41/MMBtu for the three months ended March 31, 2012 compared to an average of $4.11/MMBtu for the three months ended March 31, 2011.

Storage margin was comprised of the following:

	Three Months Ended March 31,		
	2012	2011	Change
Withdrawals from storage natural gas inventory (MMBtu)	546,734	15,124,753	(14,578,019)
Margin on physical sales	$(875)	$10,512	$(11,387)
Settlements of derivatives	61,559	5,770	55,789
Realized margin on natural gas inventory transactions	60,684	16,282	44,402
Fair value inventory adjustments	(50,301)	1,522	(51,823)
Unrealized losses on derivatives	(25,397)	(10,957)	(14,440)
Margin recognized on natural gas inventory and related derivatives	(15,014)	6,847	(21,861)
Revenues from fee-based storage	8,479	9,601	(1,122)
Other costs	(218)	(166)	(52)
Total storage margin	$(6,753)	$16,282	$(23,035)

The decrease in our storage margin was principally driven by a decline in the margin on physical sales due to a limited withdrawal of natural gas from our Bammel storage facility as a result of warmer than normal weather patterns and unrealized losses on derivatives. Additionally, we experienced a decline in fee-based storage revenue due to the cessation in late 2011 of fixed fee contracts representing 4.5 Bcf of storage capacity. The decreases were offset by realized gains on the settlement of derivatives as discussed above.

Unrealized (Losses) Gains on Commodity Risk Management Activities. Unrealized losses on commodity risk management activities reflect the net impact from unrealized gains and losses on storage and non-storage derivatives, as well as fair value adjustments on inventory. Unrealized losses increased for the three months ended March 31, 2012 primarily due to the impacts of holding a larger volume of natural gas in our Bammal storage facility due to the warmer weather noted above. During the three months ended March 31, 2012 we settled derivatives for a $61.6 million gain with no offset from the withdrawal of physical gas. We also recorded additional mark-to-market losses of $6.0 million in 2012 not related to storage.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased principally due to a decrease in natural gas consumed for compression of $4.3 million and a decrease in electricity costs of $1.3 million.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased primarily due to the completion of pipeline projects in connection with the continued expansion of our pipeline system.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses increased as a result of an increase of $4.2 million in employee-related costs (including allocated overhead expenses).

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Interstate Transportation

	Three Months Ended March 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d)	3,153,073	2,250,166	902,907
Natural gas sold (MMBtu/d)	20,517	23,586	(3,069)
Revenues	$128,276	$105,101	$23,175
Operating expenses, excluding non-cash compensation expense	(27,921)	(26,625)	(1,296)
Selling, general and administrative, excluding non-cash compensation expense	(10,143)	(6,653)	(3,490)
Adjusted EBITDA related to unconsolidated affiliates	22,768	8,287	14,481
Segment Adjusted EBITDA	$112,980	$80,110	$32,870

Volumes. Transported volumes increased primarily due to the expansion of the Tiger pipeline, which was placed in service in August 2011. The increase was slightly offset by a decrease in transportation volumes on the Transwestern pipeline primarily due to lower basis differentials on the eastern side of the pipeline.

Revenues. Interstate transportation revenues increased by $23.2 million primarily as a result of a $30.3 million increase in revenues from Tiger pipeline resulting from increased reservation charges associated with the full contractual commitments from our expansion shippers. This increase was offset by decreases in transportation and operational sales revenues of $3.6 million and $3.5 million, respectively, from the Transwestern pipeline as a result of lower margin and volumes driven principally by lower basis differentials on the eastern side of the pipeline.

Operating Expenses, Excluding Non-Cash Compensation Expense. Interstate transportation operating expenses increased from the prior year primarily due an increase in property taxes related to Tiger's expansion project in 2011.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Interstate transportation selling, general and administrative expenses increased primarily due to higher allocated corporate and pipeline costs, higher outside services costs, and employee-related expenses.

Adjusted EBITDA Related to Unconsolidated Affiliates. Interstate transportation Adjusted EBITDA from unconsolidated affiliates increased by $14.5 million primarily due to the increase of $10.2 million and $4.3 million in Adjusted EBITDA related to FEP and Citrus, respectively. The higher earnings from FEP resulted from increased reservation charges associated with the full contractual commitments from our expansion shippers. The investment in Citrus was acquired on March 26, 2012.

Midstream

	Three Months Ended March 31,		
	2012	2011	Change
Gathered volumes (MMBtu/d)	2,399,000	1,927,000	472,000
NGLs produced (Bbls/d)	66,142	49,752	16,390
Equity NGLs produced (Bbls/d)	18,082	15,894	2,188
Revenues	$554,558	$651,256	$(96,698)
Cost of products sold	425,028	548,343	(123,315)
Gross margin	129,530	102,913	26,617
Unrealized (gains) losses on commodity risk management activities	2,412	(499)	2,911
Operating expenses, excluding non-cash compensation expense	(28,211)	(24,407)	(3,804)
Selling, general and administrative, excluding non-cash compensation expense	(3,443)	(2,631)	(812)
Segment Adjusted EBITDA	$100,288	$75,376	$24,912

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Volumes. NGL production increased primarily due to increased inlet volumes at our La Grange and Chisholm plants as a result of more production in the Eagle Ford area, offset by reduced inlet volumes at our Godley plant due to lower production in the Barnett Shale. The increase in equity NGL production reflected higher overall production and was offset by a higher concentration of volumes under fee-based contracts during the three months ended March 31, 2012 as compared to the same period last year.

Gross Margin. The components of our midstream segment gross margin were as follows:

	Three Months Ended March 31,		
	2012	2011	Change
Gathering and processing fee-based revenues	$75,901	$59,607	$16,294
Non fee-based contracts and processing	60,506	46,370	14,136
Other	(6,877)	(3,064)	(3,813)
Total gross margin	$129,530	$102,913	$26,617

Midstream gross margin increased due to the following:

- Increased volumes, primarily as a result of increased capacity from growth projects in the Eagle Ford Shale, resulted in increased fee-based revenues of $17.1 million. Additionally, increased volumes resulting from assets located in Louisiana and West Virginia provided an increase in our fee-based margin of $3.6 million. These increases were offset partly by volume declines in North Texas.

- Our non fee-based gross margins increased $14.1 million primarily due to higher equity NGL volumes resulting from increased capacity from growth projects in the Eagle Ford Shale, offset by slightly lower NGL prices. The composite NGL price decreased for the three months ended March 31, 2012 to $1.17 per gallon from $1.20 per gallon during the same period last year.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized losses of $2.4 million during the three months ended March 31, 2012 compared to unrealized gains of $0.5 million in the same period last year primarily due less favorable market conditions.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased $3.8 million between the periods primarily due to an increase in ad valorem taxes of $2.5 million, an increase in operating expenses of $0.6 million, an increase in employee expenses of $0.4 million and an increase in other costs of $0.3 million related to our growth projects recently placed into service in the Eagle Ford Shale.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased primarily due to increases in employee related costs and professional fees.

NGL Transportation and Services

	Three Months Ended March 31,		
	2012	2011	Change
NGL transportation volumes (Bbls/d)	150,881	—	150,881
NGL fractionation volumes (Bbls/d)	20,006	—	20,006
Revenues	$167,551	$—	$167,551
Cost of products sold	98,647	—	98,647
Gross margin	68,904	—	68,904
Operating expenses, excluding non-cash compensation expense	(13,636)	—	(13,636)
Selling, general and administrative, excluding non-cash compensation expense	(5,065)	—	(5,065)
Adjusted EBITDA related to unconsolidated affiliates	261	—	261
Adjusted EBITDA attributable to noncontrolling interest	(15,247)	—	(15,247)
Segment Adjusted EBITDA	$35,217	$—	$35,217

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Our NGL Transportation and Services segment primarily reflects the results from Lone Star, which was formed in 2011 and acquired all of the membership interests in LDH on May 2, 2011, as well as multiple other wholly-owned or joint venture pipelines that have recently become operational.

Gross Margin. The components of our NGL transportation and services segment gross margin were as follows:

	Three Months Ended March 31,		
	2012	2011	Change
Storage revenues	$31,631	$—	$31,631
Transportation revenues	13,072	—	13,072
Processing and fractionation revenues	24,201	—	24,201
Total gross margin	$68,904	$—	$68,904

Retail Propane and Other Retail Propane Related

	Three Months Ended March 31,		
	2012	2011	Change
Retail propane gallons (in thousands)	26,392	204,140	(177,748)
Revenues	$80,006	$557,215	$(477,209)
Cost of products sold	48,702	315,420	(266,718)
Gross margin	31,304	241,795	(210,491)
Unrealized (gains) losses on commodity risk management activities	1,998	238	1,760
Operating expenses, excluding non-cash compensation expense	(17,989)	(87,592)	69,603
Selling, general and administrative, excluding non-cash compensation expense	(1,454)	(12,086)	10,632
Adjusted EBITDA related to unconsolidated affiliates	74,936	—	74,936
Segment Adjusted EBITDA	$88,795	$142,355	$(53,560)

On January 12, 2012, we received an equity investment in AmeriGas as partial consideration for the contribution of our Propane Business to AmeriGas. As a result, for three months ended March 31, 2012, the retail propane and other retail propane related segment data presented above only includes eleven days of consolidated activity related to our Propane Business. For the three months ended March 31, 2012, the retail propane and other retail propane related segment data presented above also includes our equity investment in AmeriGas. We recorded equity in earnings related to AmeriGas of $39.4 million for the three months ended March 31, 2012.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our Unitholders will depend on our future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond management’s control.

We currently believe that our business has the following future capital requirements, which do not include amounts needed for the recently announced merger agreement to acquire Sunoco Inc.:

- growth capital expenditures for our midstream and intrastate transportation and storage segments, primarily for the construction of new pipelines and compression, for which we expect to spend between $700 million and $800 million for the remainder of 2012;
- growth capital expenditures for our NGL transportation and services segment of between $1.1 billion and $1.2 billion for the remainder of 2012, for which we expect to receive capital contributions from Regency related to their 30% share of Lone Star of between $300 million and $350 million; and
- maintenance capital expenditures of between $90 million and $100 million for the remainder of 2012, which include (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; and (iii) capital expenditures related to NGL transportation and services, including amounts

expected to be funded by our joint venture partner related to its 30% interest in Lone Star.

We do not expect to make any growth capital expenditures in 2012 related to our interstate transportation segment.

The assets used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, replacing pipe caused by delays from mills, limited selection of mills capable of producing large diameter pipe in a timely manner, higher steel prices and other factors beyond our control. However, we include these factors in our anticipated growth capital expenditures for each year.

As discussed in Note 5 to our consolidated financial statements included in this report, we completed the Citrus Merger on March 26, 2012. In January 2012, we issued senior notes to fund substantially all of the cash portion of the purchase price. We also intend to issue sufficient additional equity to maintain our investment grade credit rating and to use the proceeds from such equity issuances to repay other indebtedness and fund capital expenditures. In addition, we may enter into other acquisitions, including the potential acquisition of new pipeline systems.

We generally fund our capital requirements with cash flows from operating activities, borrowings under our revolving credit facility, the issuance of long-term debt or Common Units or a combination thereof. Based on our current estimates, we expect to utilize capacity under our revolving credit facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2012; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Cash Flows

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions and other factors.

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in “Results of Operations” above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense result from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of propane and natural gas inventories, and the timing of advances and deposits received from customers.

Three months ended March 31, 2012 compared to three months ended March 31, 2011. Cash provided by operating activities during 2012 was $255.0 million as compared to $290.6 million for 2011 and net income was $1.13 billion and $247.2 million for 2012 and 2011, respectively. The difference between net income and cash provided by operating activities for the three months ended March 31, 2012 primarily consisted of the gain on the deconsolidation of propane of $1.06 billion and changes in operating assets and liabilities of $34.4 million, offset by the loss on extinguishment of debt of $115.0 million and non-cash items totaling $124.3 million. The difference between net income and cash provided by operating activities for the three months ended March 31, 2011 primarily consisted of non-cash items totaling $112.3 million and changes in operating assets and liabilities of $71.8 million.

The non-cash activity in 2012 and 2011 consisted primarily of depreciation and amortization of $101.9 million and $96.0 million, respectively. In addition, non-cash compensation expense was $10.7 million and $10.2 million for 2012

and 2011, respectively.
Cash paid for interest, net of interest capitalized, was $133.5 million and $129.0 million for the three months ended March 31, 2012 and 2011, respectively.

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Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, cash contributions to our joint ventures, and cash proceeds from the contribution of the Propane Business. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Three months ended March 31, 2012 compared to three months ended March 31, 2011. Cash used in investing activities during 2012 was $1.02 billion as compared to $221.6 million for 2011. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2012 were $519.0 million, including changes in accruals of $40.2 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2011 of $211.0 million, including changes in accruals of $5.6 million. In addition, in 2012 we paid cash for acquisitions of $1.91 billion, primarily for the Citrus Merger. We also received net cash proceeds of $1.38 billion from the contribution of the Propane Business.

Growth capital expenditures for 2012, before changes in accruals, were $529.4 million for our midstream, intrastate transportation and storage and NGL segments, $3.6 million for our interstate transportation segment, and $2.4 million for our retail propane and all other segments. We also incurred $23.9 million in maintenance capital expenditures, of which $13.8 million related to our midstream, intrastate transportation and storage and NGL segments, $7.5 million related to our interstate transportation segment and $2.6 million related to our retail propane and all other segments. Growth capital expenditures for 2011, before changes in accruals, were $140.5 million for our midstream and intrastate transportation and storage segments, $38.4 million for our interstate transportation segment, and $7.0 million for our retail propane and all other segments. We also incurred $19.6 million in maintenance capital expenditures, of which $12.8 million related to our midstream and intrastate transportation and storage segments, $1.8 million related to our interstate transportation segment and $5.1 million related to our retail propane and all other segments.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.

Three months ended March 31, 2012 compared to three months ended March 31, 2011. Cash provided by financing activities during 2012 was $812.6 million as compared to cash used in financing activities of $58.4 million for 2011. In 2012, we received $76.7 million in net proceeds from offerings under our equity distribution program (see Note 10 to our consolidated financial statements) as compared to net proceeds of $57.4 million under our equity distribution program in 2011. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, to fund capital contributions to joint ventures, as well as for general partnership purposes. During 2012, we had a net increase in our debt level of $1.00 billion as compared to a net increase of $158.5 million for 2011, primarily due to our issuance of $2.00 billion principal amount of senior notes in January 2012 to partially fund the Citrus Merger, partially offset by the repurchase of $750 million principal amount of senior notes in connection with our tender offers announced in January 2012 (See Note 9 to our consolidated financial statements). In connection with the issuance of senior notes in January 2012, we incurred debt issuance costs of $18.1 million. We paid distributions of $318.6 million to our partners in 2012 as compared to $274.2 million in 2011. In addition, we received a capital contribution of $67.1 million from Regency for its noncontrolling interest in Lone Star as compared to no contributions received in 2011.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	March 31, 2012	December 31, 2011
ETP Senior Notes	$7,800,000	$6,550,000
Transwestern Senior Notes	870,000	870,000
HOLP Senior Notes	—	71,314
Revolving credit facility	190,000	314,438
Other long-term debt	616	10,345
Unamortized discounts	(21,140)	(15,457)
Fair value adjustments related to interest rate swaps	10,244	11,647
Total debt	8,849,720	7,812,287
Less: current maturities	108,224	424,117
Long-term debt, less current maturities	$8,741,496	$7,388,170

The terms of our consolidated indebtedness are described in more detail in our Annual Report on Form 10-K for the year ended December 31, 2011, filed with the SEC on February 22, 2012 and in Note 9 to our consolidated financial statements.

ETP Credit Facility

The indebtedness under ETP's revolving 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.

As of March 31, 2012, we had $190.0 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $2.28 billion after taking into account letters of credit of $28.3 million. The weighted average interest rate on the total amount outstanding as of March 31, 2012 was 1.74%.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Transaction described in Note 5, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550 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 Propane Transaction, ETP entered into and delivered 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.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements at March 31, 2012.

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Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of March 31, 2012 (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$8,860,616	$108,224	$730,160	$1,065,228	$6,957,004
Interest on long-term debt (a)	5,061,255	331,152	834,802	699,550	3,195,751
Payments on derivatives	89,179	1,087	87,501	—	591
Purchase commitments (b)	70,146	69,201	945	—	—
Operating lease obligations	232,665	14,567	35,343	32,767	149,988
Totals (c)	$14,313,861	$524,231	$1,688,751	$1,797,545	$10,303,334

(a) Interest payments on long-term debt are based on the principal amount of debt obligations as of March 31, 2012. With respect to variable rate debt, the interest payments were estimated using the interest rate as of March 31, 2012. To the extent interest rates change, our contractual obligations for interest payments will change. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for further discussion.

(b) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for propane and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the March 31, 2012 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated.

(c) Excludes non-current deferred tax liabilities of $148.7 million due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Under our Partnership Agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash, as defined, for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for our operations.

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

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The total amounts of distributions declared during the three months ended March 31, 2012 and 2011 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Three Months Ended March 31,	
	2012	2011
Limited Partners:		
Common Units	$205,172	$186,321
Class E Units	3,121	3,121
General Partner interest	4,914	4,896
IDRs	99,548	103,182
Total distributions declared	$312,755	$297,520

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to approximately $220 million of the IDR's from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters.

Critical Accounting Policies

Disclosure of our critical accounting policies is included in our Annual Report on Form 10-K for the year ended December 31, 2011.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2011, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2011. Since December 31, 2011, there have been no material changes to our primary market risk exposures or how those exposures are managed.

The United States Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. This legislation requires the Commodities Futures Trading Commission (the "CFTC"), the SEC, and other regulators to promulgate rules and regulations implementing the new legislation. In December 2011, the CFTC extended relief from certain swap regulation provisions of the Legislation until July 16, 2012. The CFTC issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. It is not possible at this time to predict when the CFTC will make these regulations effective. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

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Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of March 31, 2012 and December 31, 2011, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power and gallons for propane. Dollar amounts are presented in thousands.

	March 31, 2012			December 31, 2011		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX (1)	11,280,000	$(25,050)	$ 1,066	(151,260,000)	$(22,582)	$ 2,593
Power:						
Forwards	(1,000)	410	33	—	—	—
Options – Calls	84	107	9	—	—	—
Options – Puts	32	44	4	—	—	—
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(43,882,500)	(793)	56	(61,420,000)	4,024	266
Swing Swaps IFERC	(62,117,500)	(1,553)	589	92,370,000	(1,072)	138
Fixed Swaps/Futures	(2,042,500)	3,029	2,493	797,500	(4,301)	145
Forward Physical Contracts	(43,604,214)	2,449	2,323	(10,672,028)	(13)	1,118
Propane:						
Forwards/Swaps	6,571,500	(879)	828	38,766,000	(4,122)	5,290
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(25,920,000)	95	190	(28,752,500)	(808)	181
Fixed Swaps/Futures	(55,690,000)	33,987	14,959	(45,822,500)	70,761	14,048
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(17,400,000)	100	115	—	—	—
Fixed Swaps/Futures	(35,650,000)	16,672	11,033	—	—	—
Options – Puts	2,700,000	6,765	597	3,600,000	6,435	933
Options – Calls	(2,700,000)	(2)	3	(3,600,000)	(12)	13

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

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income or in other comprehensive income. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

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Interest Rate Risk

As of March 31, 2012, we had $190.0 million of floating rate debt outstanding under our revolving credit facility. A hypothetical change of 100 basis points would result in a change to interest expense of $1.9 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

We had the following interest rate swaps outstanding as of March 31, 2012 and December 31, 2011 (dollars in thousands), none of which are designated as hedges for accounting purposes:

Term	Type [(1)]	Notional Amount Outstanding	
		March 31, 2012	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.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on non-hedged interest rate derivatives) of approximately $42.5 million as of March 31, 2012 and $82.7 million as of December 31, 2011. For the $600.0 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows (swap settlements) of $6.0 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

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, midstream 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.

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.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

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Under the supervision and with the participation of senior management, including the Chief Executive Officer ("Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of March 31, 2012 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2011 and Note 13 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.

ITEM 1A. RISK FACTORS

Our recently announced entry into a definitive merger agreement whereby we will acquire Sunoco Inc. ("Sunoco Merger") presents several risks. Some risks are similar to the risks associated with our existing business that have recently been disclosed. However, certain of those risks represent new risks related to our business or existing risks that have become more significant. The following risk factors should be read in conjunction with our risk factors described in "Part I — Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2011.

The recently announced Sunoco Merger is subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

The recently announced Sunoco Merger involves potential risks, including, among other things:

• the validity of our assumptions about revenues, capital expenditures and operating costs of the acquired business or assets, as well as assumptions about achieving synergies with our existing businesses;
• an increase in our interest expense and financial leverage resulting from any additional debt incurred to finance the acquisition consideration, which could offset the expected accretion to our unitholders from such acquisition and could be exacerbated by volatility in the credit or debt capital markets;
• a failure to realize anticipated benefits, such as increased distributable cash flow per unit, enhanced competitive position or new customer relationships;
• a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance the acquisition;
• difficulties operating in new geographic areas and new lines of business;
• the incurrence or assumption of unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
• the inability to hire, train or retrain qualified personnel to manage and operate our growing business and assets, including any newly acquired business or assets;
• the diversion of management's attention from our existing businesses; and
• the incurrence of significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

Our reviews of businesses or assets proposed to be acquired are inherently incomplete because it generally is not feasible to perform an in-depth review of businesses and assets involved in each acquisition given time constraints imposed by sellers. Even a detailed review of assets and businesses may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the assets or businesses to fully assess their deficiencies and potential. Inspections may not always be performed on every asset, and environmental problems are not necessarily observable even when an inspection is undertaken.

The completion of the Sunoco Merger will require us to obtain debt or equity financing, or a combination thereof, which may not be available to us on acceptable terms, or at all.

The Sunoco Merger requires that we pay approximately $2.65 billion to Sunoco shareholders as cash consideration upon the consummation of the merger which is expected to close in the third or forth quarter of 2012. We plan to fund a significant portion of this cash consideration with cash that we expect Sunoco to have on hand at the time of the consummation of the Sunoco Merger. We expect to fund the remaining portion of the cash consideration initially with borrowings under our revolving credit facility, the issuance of debt securities in the public or private markets, the issuance of common units, or a combination thereof. As of March 31, 2012, Sunoco had cash on hand of $1.99 billion;

however, Sunoco may have substantially less cash on hand at the time of the consummation of the Sunoco Merger due to unforeseen circumstances related to its business and operations. The merger agreement between Sunoco and us related to the Sunoco Merger does not require Sunoco to have any specified minimum level of cash on hand at the time of the consummation of the Sunoco Merger and, as a result, in the event that Sunoco has less cash on hand than we currently expect it will have at such time, we will be required to raise more cash through borrowings under our revolving credit facility, the issuance of debt securities or the issuance of common units. The incurrence of this additional indebtedness may increase our overall level of debt and may adversely affect our ratios of total indebtedness to EBITDA and EBITDA to interest expense. We cannot be certain that we will be able to issue our debt or equity securities on terms satisfactory to us, or at all. If we are unable to finance the cash portion of the consideration for the Sunoco Merger with borrowings under our revolving credit facility or through the issuance of debt securities in the public or private markets, we could be required to seek alternative financing, the terms of which may not be attractive to us, or we may be unable to fulfill our obligations under the Sunoco Merger.

The failure to successfully combine the businesses of ETP and Sunoco in the expected time frame may adversely affect ETP's future results.

The success of the Sunoco Merger will depend, in part, on the ability of ETP to realize the anticipated benefits from combining the businesses of ETP and Sunoco. To realize these anticipated benefits, ETP's and Sunoco's businesses must be successfully combined. If the combined company is not able to achieve these objectives, the anticipated benefits of the Sunoco Merger may not be realized fully or at all or may take longer to realize than expected. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the Sunoco Merger.

ETP and Sunoco, including their respective subsidiaries, have operated and, until the completion of the Sunoco Merger, will continue to operate independently. It is possible that the integration process could result in the loss of key employees, as well as the disruption of each company's ongoing businesses or inconsistencies in their standards, controls, procedures and policies. Any or all of those occurrences could adversely affect ETP's ability to maintain relationships with customers and employees after the Sunoco Merger or to achieve the anticipated benefits of the Sunoco Merger. Integration efforts between the two companies will also divert management attention and resources. These integration matters could have an adverse effect on each of ETP and Sunoco.

The completion of the Sunoco Merger is subject to the satisfaction of certain conditions to closing, and the date that the Sunoco Merger would be consummated is uncertain.

The completion of the Sunoco Merger is subject to the approval of the Sunoco stockholders, the absence of a material adverse change to the business or results of operation of ETP and Sunoco, the receipt of necessary regulatory approvals and the satisfaction or waiver of other conditions specified in the merger agreement related to the Sunoco transaction. Another party may express public interest in completing a transaction with Sunoco similar to the Sunoco Merger and may be prepared to pay consideration to the stockholders of Sunoco in an amount greater than ETP is willing to pay, which could delay or prevent the stockholders of Sunoco from approving the Sunoco Merger. In the event those conditions to closing are not satisfied or waived, we would not complete the Sunoco Merger.

While we expect to complete the Sunoco Merger in the second half of 2012, the completion date of the Sunoco Merger might be later than expected due to delays in obtaining required regulatory approvals or other unforeseen events.

The pendency of the Sunoco Merger could materially adversely affect the future business and operations of ETP or Sunoco or result in a loss of Sunoco employees.

In connection with the pending Sunoco Merger, it is possible that some customers, suppliers and other persons with whom ETP, ETP's subsidiaries or Sunoco have a business relationship may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationship with Sunoco as a result of the Sunoco Merger, which could negatively impact revenues, earnings and cash flows of ETP or Sunoco, as well as the market prices of ETP common units or shares of Sunoco common stock, regardless of whether the Sunoco Merger is completed. Similarly, current and prospective employees of Sunoco may experience uncertainty about their future roles with ETP and Sunoco following completion of the Sunoco Merger, which may materially adversely affect the ability of ETP and Sunoco to attract and retain key employees.

Failure to complete the Sunoco Merger could negatively impact the unit price of ETP and its respective future businesses and financial results.

If the Sunoco Merger is not completed, the ongoing business of ETP may be adversely affected and ETP will be subject to several risks and consequences, including the following:

- ETP will be required to pay certain costs relating to the Sunoco Merger, whether or not the Sunoco Merger is completed, such as legal, accounting, financial advisor and printing fees;
- ETP would not realize the expected benefits of the Sunoco Merger;

• under the merger agreement, ETP is subject to certain restrictions on the conduct of its business prior to completing the Sunoco Merger which may adversely affect its ability to execute certain of its business strategies; and
• matters relating to the Sunoco Merger may require substantial commitments of time and resources by ETP management, which could otherwise have been devoted to other opportunities that may have been beneficial to ETP.

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In addition, if the Sunoco Merger is not completed, ETP may experience negative reactions from the financial markets and from their respective customers and employees. ETP also could be subject to litigation related to any failure to complete the Sunoco Merger or to enforcement proceedings commenced against ETP to attempt to force it to perform its obligations under the merger agreement.

Pending litigation against ETP and Sunoco could result in an injunction preventing completion of the Sunoco Merger, the payment of damages in the event the Sunoco Merger is completed and/or may adversely affect the combined company's business, financial condition or results of operations following the Sunoco Merger.

In connection with the Sunoco Merger, purported stockholders of Sunoco have filed several stockholder class action lawsuits against ETP, Sunoco, and the Sunoco Board. Among other remedies, the plaintiffs seek monetary damages and to enjoin the Sunoco Merger. If a final settlement is not reached, or if a dismissal is not obtained, these lawsuits could prevent or delay completion of the Sunoco Merger and result in substantial costs to ETP and Sunoco, including any costs associated with the indemnification of directors. Additional lawsuits may be filed against ETP and/or Sunoco related to the Sunoco Merger. The defense or settlement of any lawsuit or claim that remains unresolved at the time the Sunoco Merger is completed may adversely affect the combined company's business, financial condition or results of operations.

If the merger agreement is terminated, Sunoco may be obligated to reimburse ETP for costs incurred related to the Sunoco Merger and, under certain circumstances, pay a breakup fee to ETP. Sunoco may be unable to reimburse these costs or pay any potential breakup fee to ETP.

In certain circumstances, upon termination of the merger agreement, Sunoco would be responsible for reimbursing ETP for up to $20 million in expenses related to the transaction and may be obligated to pay a breakup fee to ETP of $225 million. If the merger agreement is terminated, the expense reimbursements and the breakup fee required to be paid by Sunoco under the merger agreement may require Sunoco to seek loans or borrow amounts to enable it to pay these amounts to ETP. In either case, Sunoco may not be able to fulfill such obligations.

Sunoco will be a corporate subsidiary of ETP after the Sunoco Merger and will remain subject to corporate-level income taxes.

After the Sunoco Merger, ETP will own and operate certain aspects of Sunoco's business through Sunoco as a wholly owned corporate subsidiary of ETP. Accordingly, Sunoco will continue to be subject to corporate-level tax, which may reduce the cash available for distribution to ETP and, in turn, to ETP unitholders. If the IRS were to successfully assert that Sunoco has more tax liability than ETP anticipated or legislation were enacted that increased the corporate tax rate, the cash available for distribution by ETP could be further reduced.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

(a) Exhibits

The exhibits listed on the following Exhibit Index are filed as part of this Report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

	Exhibit Number	Description
(1)	2.1	Amendment No. 2, dated as of March 23, 2012, to Amended and Restated Agreement and Plan of Merger, by and among Energy Transfer Partners, L.P., Citrus ETP Acquisition L.L.C., Energy Transfer Equity, L.P., Southern Union Company, and CrossCountry Energy, LLC dated July 19,2011.
(10)	2.2	Amendment No. 2, dated January 11, 2012, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011.
(2)	3.1	Amendment No. 1, dated March 26, 2012, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated July 28, 2009.
(3)	3.2	Amendment No. 2, dated March 26, 2012, to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated as of April 17, 2007.
(4)	3.3	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated as of August 10, 2010.
(11)	4.1	Tenth Supplemental Indenture dated as of January 17, 2012 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(5)	10.1	Guarantee of Collection made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P.
(6)	10.2	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P., and Citrus ETP Finance LLC.
(7)	10.3	Capital Stock Agreement dated June 30, 1986, as amended April 3, 2000 ("Agreement"), among El Paso Energy Corporation (as successor in interest to Sonat, Inc.); CrossCountry Energy, LLC (assignee of Enron Corp., which is the successor in interest to InterNorth, Inc. by virtue of a name change and successor in interest to Houston Natural Gas Corporation by virtue of a merger) and Citrus Corp.
(8)	10.4	Certificate of Incorporation of Citrus Corp.
(9)	10.5	By-Laws of Citrus Corp.
(12)	10.6	Contingent Residual Support Agreement by and among Energy Transfer Partners, L.P., AmeriGas Finance LLC, AmeriGas Finance Corp., AmeriGas Partners, L.P. and, for certain limited purposes, UGI Corporation, dated January 12, 2012.
(13)	10.7	Unitholder Agreement by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated January 12, 2012.
(14)	10.8	Letter agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P, dated January 11, 2012.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(*)	101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of March 31, 2012 and December 31, 2011; (ii) our Consolidated Statements of Operations for the three months ended March 31, 2012 and 2011; (iii) our Consolidated Statements of Comprehensive Income for the three months ended March 31, 2012 and 2011; (iv) our Consolidated Statement of Partners' Capital for the three months ended March 31, 2012; (v) our Consolidated Statements of Cash Flows for the three months ended March 31, 2012 and 2011; and (vi) the notes to our Consolidated Financial Statements.

* Filed herewith.
** Furnished herewith.

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(1) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on March 28, 2012.
(2) Incorporated by reference to Exhibit 3.1 to Registrant's Form 8-K filed on March 28, 2012.
(3) Incorporated by reference to Exhibit 3.2 to Registrant's Form 8-K filed on March 28, 2012.
(4) Incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on March 28, 2012.
(5) Incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on March 28, 2012.
(6) Incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on March 28, 2012.
(7) Incorporated by reference to Exhibit 10(t) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006.
(8) Incorporated by reference to Exhibit 10(q) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006.
(9) Incorporated by reference to Exhibit 10(r) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006.
(10) Incorporated by reference to Exhibit 10.1 to Exhibit 2.1 to Registrant's Form 8-K filed on January 13, 2012.
(11) Incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on January 17, 2012.
(12) Incorporated by reference to Exhibit 10.1 to Exhibit 10.1 to Registrant's Form 8-K filed on January 13, 2012.
(13) Incorporated by reference to Exhibit 10.1 to Exhibit 10.2 to Registrant's Form 8-K filed on January 13, 2012.
(14) Incorporated by reference to Exhibit 10.1 to Exhibit 10.3 to Registrant's Form 8-K filed on January 13, 2012.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	ENERGY TRANSFER PARTNERS, L.P.
	By: Energy Transfer Partners GP, L.P., its General Partner
	By: Energy Transfer Partners, L.L.C., its General Partner
Date: May 9, 2012	By: /s/ Martin Salinas, Jr. Martin Salinas, Jr. (Chief Financial Officer duly authorized to sign on behalf of the registrant)