Energy Transfer Partners, L.P.
Form 10-Q
August 08, 2012
Table of Contents

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 June 30, 2012

or

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

Commission file number 1-11727

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

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

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

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

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

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

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

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

At August 1, 2012, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	245,388,307	Common Units

Table of Contents

FORM 10-Q
TABLE OF CONTENTS
Energy Transfer Partners, L.P. and Subsidiaries

Table of Contents

Forward-Looking Statements

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

Definitions

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

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

Table of Contents

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
NYMEX	New York Mercantile Exchange
OTC	over-the-counter
OSHA	federal Occupational Safety and Health Act
PCBs	polychlorinated biphenyls
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company, a subsidiary of ETE

Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Tcf	trillion cubic feet
Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC

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

Table of Contents

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$186,910	$106,816
Marketable securities	11	1,229
Accounts receivable, net of allowance for doubtful accounts of $538 and $7,651 as of June 30, 2012 and December 31, 2011, respectively	438,625	568,579
Accounts receivable from related companies	45,242	81,753
Inventories	230,061	306,740
Exchanges receivable	18,511	18,808
Price risk management assets	16,921	11,429
Other current assets	101,280	180,140
Total current assets	1,037,561	1,275,494
PROPERTY, PLANT AND EQUIPMENT	13,993,414	13,983,888
ACCUMULATED DEPRECIATION	(1,399,713)	(1,677,522)
	12,593,701	12,306,366
ADVANCES TO AND INVESTMENTS IN AFFILIATES	3,259,129	200,612
LONG-TERM PRICE RISK MANAGEMENT ASSETS	38,974	25,537
GOODWILL	600,152	1,219,597
INTANGIBLE ASSETS, net	170,062	331,409
OTHER NON-CURRENT ASSETS, net	159,840	159,601
Total assets	$17,859,419	$15,518,616

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

Table of Contents

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

	June 30, 2012	December 31, 2011
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$299,322	$401,053
Accounts payable to related companies	160	33,373
Exchanges payable	12,432	17,906
Price risk management liabilities	9,091	79,518
Accrued and other current liabilities	747,686	629,202
Current maturities of long-term debt	108,050	424,117
Total current liabilities	1,176,741	1,585,169
LONG-TERM DEBT, less current maturities	9,043,393	7,388,170
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	140,554	42,303
OTHER NON-CURRENT LIABILITIES	167,208	152,550
COMMITMENTS AND CONTINGENCIES (Note 13)		
EQUITY:		
General Partner	186,001	181,646
Limited Partners:		
Common Unitholders	6,347,741	5,533,492
Accumulated other comprehensive income (loss)	(12,177)	6,569
Total partners’ capital	6,521,565	5,721,707
Noncontrolling interest	809,958	628,717
Total equity	7,331,523	6,350,424
Total liabilities and equity	$17,859,419	$15,518,616

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

2

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
REVENUES:				
Natural gas sales	$456,792	$684,686	$878,208	$1,284,154
NGL sales	334,200	274,785	695,777	431,686
Gathering, transportation and other fees	386,500	379,714	775,244	715,813
Retail propane sales	11,637	220,296	87,082	748,762
Other	51,185	68,614	109,863	135,257
Total revenues	1,240,314	1,628,095	2,546,174	3,315,672
COSTS AND EXPENSES:				
Cost of products sold	667,434	1,008,628	1,440,919	2,003,085
Operating expenses	128,839	189,302	256,829	377,791
Depreciation and amortization	99,102	104,972	201,019	200,936
Selling, general and administrative	55,500	54,774	104,023	100,306
Total costs and expenses	950,875	1,357,676	2,002,790	2,682,118
OPERATING INCOME	289,439	270,419	543,384	633,554
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(134,310)	(116,466)	(271,130)	(223,706)
Equity in earnings of affiliates	466	5,040	55,091	6,673
Gain on deconsolidation of Propane Business	765	—	1,056,709	—
Gains (losses) on disposal of assets	146	(528)	(878)	(2,254)
Loss on extinguishment of debt	—	—	(115,023)	—
Gains (losses) on non-hedged interest rate derivatives	(35,917)	2,111	(8,022)	3,890
Allowance for equity funds used during construction	123	1,201	227	69
Other, net	3,099	622	3,673	1,972
INCOME BEFORE INCOME TAX EXPENSE	123,811	162,399	1,264,031	420,198
Income tax expense	24	5,783	14,147	16,380
NET INCOME	123,787	156,616	1,249,884	403,818
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	12,366	8,388	23,730	8,388
NET INCOME ATTRIBUTABLE TO PARTNERS	111,421	148,228	1,226,154	395,430
GENERAL PARTNER’S INTEREST IN NET INCOME	108,806	105,892	225,343	213,431
LIMITED PARTNERS’ INTEREST IN NET INCOME	$2,615	$42,336	$1,000,811	$181,999
BASIC NET INCOME PER LIMITED PARTNER UNIT	$0.00	$0.19	$4.35	$0.89
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	229,663,164	208,615,415	228,097,706	201,259,140
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$0.00	$0.19	$4.33	$0.88
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	230,680,644	209,675,032	229,141,002	202,364,488

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

3

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income	$123,787	$156,616	$1,249,884	$403,818
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(6,615)	(5,443)	(10,097)	(22,411)
Change in value of derivative instruments accounted for as cash flow hedges	(6,517)	2,298	13,871	8,457
Change in value of available-for-sale securities	—	(643)	(114)	(35)
Change in other comprehensive income (loss) from equity investments	(22,406)	—	(22,406)	—
	(35,538)	(3,788)	(18,746)	(13,989)
Comprehensive income	88,249	152,828	1,231,138	389,829
Less: Comprehensive income attributable to noncontrolling interest	12,366	8,388	23,730	8,388
Comprehensive income attributable to partners	$75,883	$144,440	$1,207,408	$381,441

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

Table of Contents

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

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (loss)	Noncontrolling Interest	Total
Balance, December 31, 2011	$181,646	$5,533,492	$ 6,569	$ 628,717	$6,350,424
Distributions to partners	(221,001)	(407,230)	—	—	(628,231)
Distributions to noncontrolling interest	—	—	—	(17,743)	(17,743)
Units issued for cash	—	93,584	—	—	93,584
Capital contributions from noncontrolling interest	—	—	—	175,254	175,254
Units issued in connection with acquisitions	—	112,000	—	—	112,000
Distributions on unvested unit awards	—	(4,043)	—	—	(4,043)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	13	21,074	—	—	21,087
Other comprehensive loss, net of tax	—	—	(18,746)	—	(18,746)
Other, net	—	(1,947)	—	—	(1,947)
Net income	225,343	1,000,811	—	23,730	1,249,884
Balance, June 30, 2012	$186,001	$6,347,741	$ (12,177)	$ 809,958	$7,331,523

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

Table of Contents

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

	Six Months Ended June 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$1,249,884	$403,818
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	201,019	200,936
Amortization of finance costs charged to interest	5,392	4,663
Loss on extinguishment of debt	115,023	—
Non-cash compensation expense	20,992	20,789
Gain on deconsolidation of Propane Business	(1,056,709)	—
Losses on disposal of assets	878	2,254
Distributions on unvested awards	(4,043)	(3,689)
Distributions in excess of (less than) equity in earnings of affiliates, net	(118)	1,885
Other non-cash	8,536	1,267
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation (see Note 3)	58,635	7,522
Net cash provided by operating activities	599,489	639,445
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for Citrus Merger	(1,895,000)	—
Cash proceeds from contribution and sale of propane operations	1,442,536	—
Cash paid for all other acquisitions, net of cash received	(10,317)	(1,948,611)
Capital expenditures (excluding allowance for equity funds used during construction)	(1,016,927)	(621,915)
Contributions in aid of construction costs	12,056	13,967
Distributions from (advances to) affiliates, net	51,941	(22,668)
Proceeds from the sale of assets	13,265	2,922
Net cash used in investing activities	(1,402,446)	(2,576,305)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	3,288,857	4,171,535
Repayments of long-term debt	(1,986,515)	(2,934,308)
Net proceeds from issuance of Limited Partner units	93,584	770,187
Capital contributions received from noncontrolling interest	151,239	591,680
Distributions to partners	(628,231)	(568,607)
Distributions to noncontrolling interest	(17,743)	—
Debt issuance costs	(18,140)	(12,261)
Net cash provided by financing activities	883,051	2,018,226
INCREASE IN CASH AND CASH EQUIVALENTS	80,094	81,366
CASH AND CASH EQUIVALENTS, beginning of period	106,816	49,540
CASH AND CASH EQUIVALENTS, end of period	$186,910	$130,906

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

Table of Contents

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 that directly owns a 50% interest in the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry Energy, LLC, a Delaware limited liability company that indirectly owns a 50% interest in Citrus Corp., which owns 100% of the FGT interstate natural gas pipeline.
- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

On January 12, 2012, we contributed HOLP and Titan, our subsidiaries that formerly operated our propane operations, to AmeriGas. See Note 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 the Partnership as of June 30, 2012 and for the three and six month periods ended June 30, 2012 and 2011, have been prepared in accordance with GAAP for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all 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.

Table of Contents

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of the Partnership as of June 30, 2012, and the Partnership's results of operations and cash flows for the three and six months ended June 30, 2012 and 2011. The unaudited interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2011, as filed with the SEC on February 22, 2012.

Certain prior period amounts have been reclassified to conform to the 2012 presentation. These reclassifications had no impact on net income or total equity.

Pending Sunoco Merger

On April 30, 2012, we announced our entry into a definitive merger agreement whereby we will acquire Sunoco in exchange for ETP Common Units and cash. Under the terms of the merger agreement, Sunoco shareholders may elect to 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 of an ETP Common Unit. The cash and unit elections, however, will be subject to proration to ensure that the total amount of cash paid and the total number of ETP Common Units issued in the merger to Sunoco shareholders as a whole are equal to the total amount of cash and number of ETP Common Units that would have been paid and issued if all Sunoco shareholders received the standard mix of consideration. Upon closing, Sunoco shareholders are expected to own approximately 20% of ETP's outstanding limited partner units. 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.

Sunoco owns the general partner interest of Sunoco Logistics, consisting of a 2% general partner interest, 100% of the IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. Sunoco also generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States.

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

Pending Holdco Transaction

On June 15, 2012, ETE and ETP entered into a transaction agreement pursuant to which, immediately following and subject to the closing of the Sunoco merger, (i) ETE will contribute its interest in Southern Union into an ETP-controlled entity in exchange for a 60% equity interest in the new entity, to be called ETP Holdco Corporation ("Holdco") and (ii) ETP will contribute its interest in Sunoco to Holdco and will retain a 40% equity interest in Holdco (the "Holdco Transaction"). Prior to the contribution of Sunoco to Holdco, Sunoco will contribute its interests in Sunoco Logistics to ETP in exchange for 50,706,000 Class F Units representing limited partner interests in ETP ("Class F Units") plus an additional number of Class F Units determined based upon the amount of cash contributed to ETP by Sunoco at the closing of the merger, as calculated in accordance with the merger agreement. The Class F Units will be entitled to 35% of the quarterly cash distributions generated by ETP and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year. Pursuant to a stockholders agreement between ETE and ETP, ETP will control Holdco. Consequently, ETP expects to consolidate Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

Southern Union is engaged primarily in the transportation, storage, gathering, processing and distribution of natural gas. Southern Union owns and operates interstate pipeline that transports natural gas from the Gulf of Mexico, South Texas and the Panhandle regions of Texas and Oklahoma to major U.S. markets in the Midwest and Great Lakes regions. It owns and operates a LNG import terminal located on Louisiana's Gulf Coast. Through Southern Union Gas Services, it owns natural gas and NGL pipelines, cryogenic plants, treating plants and is engaged in connecting producing wells of exploration and production companies to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs and redelivering natural gas and NGLs to a variety of markets in West Texas and New Mexico. Southern Union also has regulated utility operations in Missouri and Massachusetts.

Table of Contents

Under the terms of the Holdco transaction agreement, ETE will relinquish an aggregate of $210 million of IDRs over 12 consecutive quarters following the closing of the Holdco transaction.

2. ESTIMATES:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for our natural gas and NGL related operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the estimated operating results represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual values and results could differ from those estimates.

3. CASH AND CASH EQUIVALENTS:

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

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

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

	Six Months Ended June 30,	
	2012	2011
Accounts receivable	$(2,895)	$56,486
Accounts receivable from related companies	(44,891)	(46,460)
Inventories	(21,632)	30,464
Exchanges receivable	298	4,130
Other current assets	72,591	(20,539)
Other non-current assets, net	4,786	4,038
Accounts payable	(28,755)	(28,009)
Accounts payable to related companies	78,093	(12,706)
Exchanges payable	(5,473)	3,468
Accrued and other current liabilities	(9,721)	21,919
Other non-current liabilities	(5,267)	10,699
Price risk management assets and liabilities, net	21,501	(15,968)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation	$58,635	$7,522

Table of Contents

Non-cash investing and financing activities are as follows:

	Six Months Ended June 30, 2012	2011
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$425,355	$91,449
AmeriGas limited partner interests received in exchange for contribution of Propane Business (See Note 5)	$1,123,003	$—
NON-CASH FINANCING ACTIVITIES:		
Contributions receivable related to non-controlling interest	$24,015	$—
Issuance of common units in connection with acquisitions	$112,000	$—

4. INVENTORIES:

Inventories consisted of the following:

	June 30, 2012	December 31, 2011
Natural gas and NGLs, excluding propane	$148,974	$144,251
Propane	—	86,958
Appliances, parts and fittings and other	81,087	75,531
Total inventories	$230,061	$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.

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 owned 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”) to a subsidiary of ETE. As a result of the consummation of the Citrus Merger, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc. Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

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

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the “Propane Business”) to AmeriGas. We received approximately $1.46 billion in cash and approximately 29.6 million AmeriGas Common Units valued at $1.12 billion at the time of the contribution. In addition, AmeriGas assumed approximately $71.0 million of existing HOLP debt. We recognized a gain on deconsolidation of $1.06 billion for the six months ended June 30, 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 $630.0 million in excess of our proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $288.6 million is being amortized over a weighted average period of 14 years, and $341.4 million is being treated as equity method goodwill and non-amortizable intangible assets.

Table of Contents

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.

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

6. GOODWILL AND INTANGIBLE ASSETS:

A net decrease in goodwill of $619.4 million was recorded during the six months ended June 30, 2012 primarily due to the contribution of our Propane Business to AmeriGas. See Note 5.

Components and useful lives of intangible assets were as follows:

	June 30, 2012		December 31, 2011	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$226,176	$(57,333)	$338,424	$(95,239)
Noncompete agreements	—	—	15,431	(7,835)
Patents (9 years)	750	(243)	750	(201)
Other (10 to 15 years)	843	(131)	1,320	(580)
Total amortizable intangible assets	227,769	(57,707)	355,925	(103,855)
Non-amortizable intangible assets:				
Trademarks	—	—	79,339	—
Total intangible assets	$227,769	$(57,707)	$435,264	$(103,855)

Aggregate amortization expense of intangible assets was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Reported in depreciation and amortization	$4,058	$5,364	$8,465	$10,415

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

2012 (remainder)	$7,609
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

11

Table of Contents

parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations. During the period ended June 30, 2012, no transfers were made between any levels within the fair value hierarchy.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations at June 30, 2012 was $9.97 billion and $9.15 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. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

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 June 30, 2012 and December 31, 2011 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2012	
	Fair Value Total	Level 1	Level 2
Financial Assets:			
Marketable securities	$11	$11	$—
Interest rate derivatives	50,543	—	50,543
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	53,966	53,966	—
Swing Swaps IFERC	5,589	1,390	4,199
Fixed Swaps/Futures	63,572	63,572	—
Options — Puts	3,688	—	3,688
Forward Physical Contracts	976	—	976
Power:			
Forwards	42,504	6,196	36,308
Options — Puts	135	135	—
Total commodity derivatives	170,430	125,259	45,171
Total	$220,984	$125,270	$95,714
Financial Liabilities:			
Interest rate derivatives	$(140,554)	$—	$(140,554)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(73,804)	(73,804)	—
Swing Swaps IFERC	(7,504)	(2,668)	(4,836)
Fixed Swaps/Futures	(61,002)	(61,002)	—
Options — Puts	(55)	—	(55)
Options — Calls	(1)	—	(1)
Forward Physical Contracts	(386)	—	(386)
Power:			
Forwards	(41,444)	(776)	(40,668)
Total commodity derivatives	(184,196)	(138,250)	(45,946)
Total	$(324,750)	$(138,250)	$(186,500)

Table of Contents

	Fair Value Total	Fair Value Measurements at December 31, 2011	
		Level 1	Level 2
Financial 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 Contracts	699	—	699
Propane – Forwards/Swaps	9	—	9
Total commodity derivatives	299,641	279,183	20,458
Total	$337,171	$280,412	$56,759
Financial Liabilities:			
Interest rate derivatives	$(117,020)	$—	$(117,020)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(82,290)	(82,290)	—
Swing Swaps IFERC	(16,074)	(3,061)	(13,013)
Fixed Swaps/Futures	(148,111)	(148,111)	—
Options — Calls	(12)	—	(12)
Forward Physical Contracts	(712)	—	(712)
Propane – Forwards/Swaps	(4,131)	—	(4,131)
Total commodity derivatives	(251,330)	(233,462)	(17,868)
Total	$(368,350)	$(233,462)	$(134,888)

8. NET INCOME PER LIMITED PARTNER UNIT:

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

Table of Contents

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income attributable to partners	$111,421	$148,228	$1,226,154	$395,430
General Partner’s interest in net income	108,806	105,892	225,343	213,431
Limited Partners’ interest in net income	2,615	42,336	1,000,811	181,999
Additional earnings allocated from General Partner	112	160	66	508
Distributions on employee unit awards, net of allocation to General Partner	(1,980)	(1,949)	(9,498)	(3,725)
Net income available to Limited Partners	$747	$40,547	$991,379	$178,782
Weighted average Limited Partner units — basic	229,663,164	208,615,415	228,097,706	201,259,140
Basic net income per Limited Partner unit	$0.00	$0.19	$4.35	$0.89
Weighted average Limited Partner units	229,663,164	208,615,415	228,097,706	201,259,140
Dilutive effect of unvested Unit Awards	1,017,480	1,059,617	1,043,296	1,105,348
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	230,680,644	209,675,032	229,141,002	202,364,488
Diluted net income per Limited Partner unit	$0.00	$0.19	$4.33	$0.88

Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended June 30, 2012 are expected to be $334.5 million in total, which exceeds net income for the period by $223.1 million. The allocation of the distributions in excess of net income is based on the proportionate ownership interests of the Limited Partners and General Partner. Based on this allocation approach, net income per Limited Partner unit (basic and diluted) for the three months ended June 30, 2012 was approximately zero, after taking into account distributions to be paid with respect to incentive distribution rights and employee unit awards.

9. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	June 30, 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	493,449	314,438
Other long-term debt	—	10,345
Unamortized discounts	(20,847)	(15,457)
Fair value adjustments related to interest rate swaps	8,841	11,647
Total debt	9,151,443	7,812,287
Less: current maturities	(108,050)	(424,117)
Long-term debt, less current maturities	$9,043,393	$7,388,170

Table of Contents

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $12.0 million in unamortized discounts and fair value adjustments related to interest rate swaps:

2012 (remainder)	$108,050
2013	350,000
2014	379,947
2015	750,000
2016	618,449
Thereafter	6,957,003
Total	$9,163,449

Senior Notes

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

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

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

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

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 June 30, 2012, we had $493.4 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.98 billion after taking into account letters of credit of $30.3 million. The weighted average interest rate on the total amount outstanding as of June 30, 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 June 30, 2012.

Table of Contents

10. EQUITY:

Common Units Issued

The change in Common Units during the six months ended June 30, 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	379,258
Common Units issued in connection with acquisitions	2,404,062
Common Units issued under equity incentive plans	7,124
Outstanding at June 30, 2012	229,859,035

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

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

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 six months ended June 30, 2012, distributions of approximately $16.8 million were reinvested under the DRIP resulting in the issuance of 379,258 Common Units. As of June 30, 2012, a total of 5,017,063 Common Units remain available to be issued under this registration statement.

Quarterly Distributions of Available Cash

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

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

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to $220 million of the IDRs from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters following the closing of the Holdco Transaction.

AOCI

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

	June 30, 2012	December 31, 2011
Net gains on commodity related hedges	$10,229	$6,455
Unrealized gains on available-for-sale securities	—	114
Equity investments, net	(22,406)	—
Total AOCI, net of tax	$(12,177)	$6,569

16

Table of Contents

11. UNIT-BASED COMPENSATION PLANS:

During the six months ended June 30, 2012, employees were granted a total of 62,917 unvested awards with five-year service vesting requirements, and directors were granted a total of 4,400 unvested awards with three-year service vesting requirements. The weighted average grant-date fair value of these awards was $46.99 per unit. As of June 30, 2012 a total of 2,369,652 unit awards remain unvested, including the new awards granted during the period. We expect to recognize a total of $61.8 million in compensation expense over a weighted average period of 1.7 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Current expense (benefit):				
Federal	$133	$635	$(60)	$5,663
State	3,270	5,191	6,942	9,125
Total	3,403	5,826	6,882	14,788
Deferred expense (benefit):				
Federal	(1,812)	(15)	1,291	1,004
State	(1,567)	(28)	5,974	588
Total	(3,379)	(43)	7,265	1,592
Total income tax expense	$24	$5,783	$14,147	$16,380

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 $37.0 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 $150.0 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 Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of 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 $8.0 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. While Florida Gas would seek reimbursement of any costs associated with relocation of its pipeline in connection with an FDOT project, Florida Gas may not be successful in obtaining such reimbursement and, as such, could be required to bear the cost of such relocation. In any such instance, Florida Gas would seek recovery of the reimbursement costs in rates. The judge also denied all other pending post-trial motions. The FDOT/FTE filed a notice of appeal on July 12, 2011. 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.

Sunoco Litigation

Following the announcement of the Sunoco merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco's board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. The lawsuits seek an injunction barring completion of the Sunoco merger and, in some instances, damages. We and the other defendants believe that the lawsuits are without merit and we intend to defend vigorously against them.

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 $550.0 million in aggregate principal amount of 6.75% Senior Notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% Senior Notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the 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, an Administrative Law Judge certified a contested offer of settlement relating to FGT's rates and terms and conditions of service. On January 10, 2011, the contesting party withdrew its opposition to the settlement. On February 24, 2011, the FERC issued an order approving the settlement, which order settled a number of issues related to FGT's rates and terms and conditions of service. Among other matters, FGT is required to make its next NGA section 4 general rate case filing no later than November 1, 2014.

Commitments

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

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2029. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.6 million and $5.2 million for the three months ended June 30, 2012 and 2011, respectively. For the six months ended June 30, 2012 and 2011, rental expense for operating leases totaled approximately $11.2 million and $10.2 million, respectively.

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

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 December 31, 2011, accruals of approximately $18.2 million were reflected on our balance sheet related to these contingent obligations. As of June 30, 2012 there were no accruals reflected on our balance sheet related to contingent obligations, as all contingent obligations were related to our Propane Business which was contributed to AmeriGas in January (see 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 June 30, 2012 or December 31, 2011 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

CrossCountry, the ET Interstate 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 (now a subsidiary of Kinder Morgan, Inc.), 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, 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 June 30, 2012 and December 31, 2011, accruals on an undiscounted basis of $9.3 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 $5.6 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 June 30, 2012 and 2011, $2.5 million and $3.9 million, respectively, of capital costs and $4.5 million and $3.9 million of operating and maintenance costs have been incurred for pipeline integrity testing. For the six months ended June 30, 2012 and 2011, $4.6 million and $5.6 million, respectively, of capital costs and $6.0 million and $6.0 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing.

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

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

Table of Contents

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.

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

The following table details our outstanding commodity-related derivatives:

	June 30, 2012		December 31, 2011	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX [1]	7,650,000	2012-2013	(151,260,000)	2012-2013
Power (Thousand Megawatt):				
Forwards	4,800	2012-2013	—	—
Options — Puts	36,800	2012	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(55,272,500)	2012-2013	(61,420,000)	2012-2013
Swing Swaps IFERC	(19,825,000)	2012-2013	92,370,000	2012-2013
Fixed Swaps/Futures	1,062,500	2012-2014	797,500	2012
Forward Physical Contracts	(20,481,365)	2012	(10,672,028)	2012
Options — Puts	500,000	2012	—	—
Propane (Gallons):				
Forwards/Swaps	—	—	38,766,000	2012-2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(25,707,500)	2012-2013	(28,752,500)	2012
Fixed Swaps/Futures	(51,790,000)	2012-2013	(45,822,500)	2012
Hedged Item — Inventory	51,790,000	2012-2013	45,822,500	2012
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(12,850,000)	2012-2013	—	—
Fixed Swaps/Futures	(31,100,000)	2012-2013	—	—
Options — Puts	1,800,000	2012	3,600,000	2012
Options — Calls	(1,800,000)	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 $9.7 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.

Table of Contents

Interest Rate Risk

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

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

		Notional Amount Outstanding	
Term	Type [(1)]	June 30, 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.

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 $45.3 million and $66.2 million as of June 30, 2012 and December 31, 2011, respectively.

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

Table of Contents

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2012	December 31, 2011	June 30, 2012	December 31, 2011
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$12,911	$77,197	$(6,698)	$(819)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	123,426	227,337	(139,666)	(251,268)
Commodity derivatives	37,315	708	(41,054)	(4,844)
Interest rate derivatives	50,543	36,301	(140,554)	(117,020)
	211,284	264,346	(321,274)	(373,132)
Total derivatives	$224,195	$341,543	$(327,972)	$(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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$(6,534)	$2,239	13,895	8,343

	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 June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$6,616	$4,985	$10,051	$21,948

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011

Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$(1)	$458	$46	$463

24

Table of Contents

	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 June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$33,830	$15,874	$24,657	$22,291

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011
Derivatives not designated as hedging instruments:					
Commodity derivatives - Trading	Cost of products sold	$(709)	$—	$(11,295)	$—
Commodity derivatives - Non-trading	Cost of products sold	(4,571)	(11,380)	$(7,515)	$(5,001)
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	(35,917)	2,111	(8,022)	3,890
Total		$(41,197)	$(9,269)	$(26,832)	$(1,111)

We recognized $3.7 million of unrealized gains and $15.7 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 June 30, 2012 and 2011, respectively. We recognized $4.3 million and $2.1 million of unrealized gains on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the six months ended June 30, 2012 and 2011, respectively. For the three months ended June 30, 2012 and 2011 we recognized unrealized losses of $38.3 million and $16.7 million, respectively, on commodity derivatives accounted for as fair value hedges. For the six months ended June 30, 2012 and 2011 we recognized unrealized losses of $74.1 million and unrealized gains of $7.8 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 June 30, 2012, we recorded revenues of $4.0 million, cost of products sold of $8.0 million and operating expenses of $0.1 million related to transactions with Regency. For the three months ended June 30, 2011, we recorded revenues of $7.5 million, cost of products sold of $8.2 million and operating expenses of $0.4 million related to transactions with Regency. For the six months ended June 30, 2012, we recorded revenues of $12.1 million, cost of products sold of $14.1 million and operating expenses of $0.2 million related to transactions with Regency. For the six months ended June 30, 2011, we recorded revenues of $19.0 million, cost of products sold of $19.2 million and operating expenses of $1.9 million related to transactions with Regency.

In March 2012 Southern Union became a related party. For the six months ended June 30, 2012, we recorded revenues of $6.0 million and cost of products sold of $8.2 million related to transactions with Southern Union.

We received $8.9 million and $8.4 million in management fees from ETE for the provision of various general and administrative services for ETE's benefit for the six months ended June 30, 2012 and 2011, respectively. For the three months ended June 30, 2012 and 2011, we received $4.5 million and $3.5 million, respectively, in management fees from ETE for the provision of various general and administrative services for ETE's benefit. These management fees include the provision of various general and administrative services for Regency. For the three months ended June 30, 2012 and 2011, we recorded from Regency $1.8 million and $0.8 million, respectively, for reimbursement of various general and administrative expenses incurred by us. For the six months ended June 30, 2012 and 2011, we recorded from Regency $3.6 million and $3.1 million, respectively, for reimbursement of various general and administrative expenses incurred by us.

Table of Contents

16. OTHER INFORMATION:
The tables below present additional detail for certain balance sheet captions.
Other Current Assets
Other current assets consisted of the following:

	June 30, 2012	December 31, 2011
Deposits paid to vendors	$45,329	$66,231
Prepaid expenses and other	55,951	113,909
Total other current assets	$101,280	$180,140

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

	June 30, 2012	December 31, 2011
Unamortized financing costs (3 to 30 years)	$58,392	$46,618
Regulatory assets	87,502	88,993
Other	13,946	23,990
Total other non-current assets, net	$159,840	$159,601

Accrued and Other Current Liabilities
Accrued and other current liabilities consisted of the following:

	June 30, 2012	December 31, 2011
Interest payable	$177,654	$142,616
Customer advances and deposits	5,153	84,300
Accrued capital expenditures	423,594	196,789
Accrued wages and benefits	31,230	67,266
Taxes payable other than income taxes	78,956	77,073
Income taxes payable	8,780	14,422
Other	22,319	46,736
Total accrued and other current liabilities	$747,686	$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.
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

Table of Contents

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues:				
Intrastate natural gas transportation and storage:				
Revenues from external customers	$452,237	$643,653	$899,033	$1,232,331
Intersegment revenues	42,244	28,841	77,501	211,922
	494,481	672,494	976,534	1,444,253
Interstate natural gas transportation — revenues from external customers	126,900	104,850	255,176	209,951
Midstream:				
Revenues from external customers	460,077	513,584	914,176	926,779
Intersegment revenues	96,577	104,351	197,036	342,412
	556,654	617,935	1,111,212	1,269,191
NGL transportation and services:				
Revenues from external customers	147,851	93,686	302,119	93,686
Intersegment revenues	12,626	5,134	25,909	5,134
	160,477	98,820	328,028	98,820
Retail propane and other retail propane related — revenues from external customers	12,966	243,973	92,972	801,188
All other:				
Revenues from external customers	40,283	28,349	82,698	51,737
Intersegment revenues	28,921	26,472	37,078	40,899
	69,204	54,821	119,776	92,636
Eliminations	(180,368)	(164,798)	(337,524)	(600,367)
Total revenues	$1,240,314	$1,628,095	$2,546,174	$3,315,672

Table of Contents

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Segment Adjusted EBITDA				
Intrastate transportation and storage	$156,948	$171,549	$349,217	$344,364
Interstate transportation	184,419	83,498	297,399	163,608
Midstream	93,375	95,220	193,663	170,596
NGL transportation and services	38,963	24,696	74,180	24,696
Retail propane and other retail propane related	1,704	12,236	90,499	154,591
All other	(9,059)	936	(2,546)	1,579
Total	466,350	388,135	1,002,412	859,434
Depreciation and amortization	(99,102)	(104,972)	(201,019)	(200,936)
Interest expense, net of interest capitalized	(134,310)	(116,466)	(271,130)	(223,706)
Gain on deconsolidation of Propane Business	765	—	1,056,709	—
Gains (losses) on non-hedged interest rate derivatives	(35,917)	2,111	(8,022)	3,890
Non-cash unit-based compensation expense	(10,283)	(10,600)	(20,992)	(20,789)
Allowance for equity funds used during construction	123	1,201	227	69
Unrealized gains (losses) on commodity risk management activities	14,652	562	(70,974)	7,654
Gains (losses) on disposal of assets	146	(528)	(878)	(2,254)
Loss on extinguishment of debt	—	—	(115,023)	—
Adjusted EBITDA attributable to noncontrolling interest	15,810	10,585	31,057	10,585
Proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	(96,623)	(8,251)	(141,110)	(15,721)
Other	2,200	622	2,774	1,972
Income before income tax expense	123,811	162,399	$1,264,031	$420,198

	June 30, 2012	December 31, 2011
Total assets:		
Intrastate natural gas transportation and storage	$4,706,298	$4,784,630
Interstate natural gas transportation	5,606,457	3,661,098
Midstream	2,980,517	2,665,610
NGL transportation and services	3,226,953	2,360,095
Retail propane and other retail propane related	—	1,783,770
All other	1,339,194	263,413
Total	$17,859,419	$15,518,616

Table of Contents

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

(Tabular dollar amounts are in thousands)

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

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

Overview

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

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

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

Recent Developments

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 owned 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") to a subsidiary of ETE. 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 now owned by a subsidiary of Kinder Morgan Inc. 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 Rich Eagle Ford Mainline pipeline and construct a new processing facility. The pipeline expansion is expected to be completed in the fourth quarter of 2013, and the processing facility 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.

Table of Contents

Pending Sunoco Merger

On April 30, 2012, we announced our entry into a definitive merger agreement whereby we will acquire Sunoco Inc. in exchange for ETP Common Units and cash. Under the terms of the merger agreement, Sunoco shareholders may elect to 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 of an ETP Common Unit. The cash and unit elections, however, will be subject to proration to ensure that the total amount of cash paid and the total number of ETP Common Units issued in the merger to Sunoco shareholders as a whole are equal to the total amount of cash and number of ETP Common Units that would have been paid and issued if all Sunoco shareholders received the standard mix of consideration. Upon closing, Sunoco shareholders are expected to own approximately 20% of ETP's outstanding limited partner units. 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.

Sunoco owns the general partner interest of Sunoco Logistics, consisting of a 2% general partner interest, 100% of the IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. Sunoco also generates cash flow from a portfolio of approximately 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.

Pending Holdco Transaction

On June 15, 2012, ETE and ETP entered into a transaction agreement pursuant to which, immediately following and subject to the closing of the Sunoco Transaction, (i) ETE will contribute its interest in Southern Union into an ETP-controlled entity in exchange for a 60% equity interest in the new entity, to be called ETP Holdco Corporation (“Holdco”) and (ii) ETP will contribute its interest in Sunoco to Holdco and will retain a 40% equity interest in Holdco. Sunoco will contribute its interests in Sunoco Logistics to ETP in exchange for 50,706,000 Class F Units representing limited partner interests in ETP (“Class F Units”) plus an additional number of Class F Units determined based upon the amount of cash contributed to ETP by Sunoco at the closing of the merger, as calculated in accordance with the merger agreement. The Class F Units will be entitled to 35% of the quarterly cash distributions generated by ETP and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year.

Pursuant to a stockholders agreement between ETE and ETP, ETP will control Holdco. Consequently, ETP expects to consolidate Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

Southern Union is engaged primarily in the transportation, storage, gathering, processing and distribution of natural gas. Southern Union owns and operates interstate pipeline that transports natural gas from the Gulf of Mexico, South Texas and the Panhandle regions of Texas and Oklahoma to major U.S. markets in the Midwest and Great Lakes regions. It owns and operates a LNG import terminal located on Louisiana's Gulf Coast. Through Southern Union Gas Services, it owns natural gas and NGL pipelines, cryogenic plants, treating plants and is engaged in connecting producing wells of exploration and production companies to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs and redelivering natural gas and NGLs to a variety of markets in West Texas and New Mexico. Southern Union also has regulated utility operations in Missouri and Massachusetts.

Equity Offering

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

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

We also generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used to describe a pricing environment when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. Our earnings from natural gas storage we purchase, store and sell are subject to the current market prices (spot price in relation to forward price) at the time the storage gas is hedged. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical 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 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. We sold our cylinder exchange business in June 2012.

32

Table of Contents

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.

Results of Operations

Consolidated Results

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Segment Adjusted EBITDA						
Intrastate transportation and storage	$156,948	$171,549	$(14,601)	$349,217	$344,364	$4,853
Interstate transportation	184,419	83,498	100,921	297,399	163,608	133,791
Midstream	93,375	95,220	(1,845)	193,663	170,596	23,067
NGL transportation and services	38,963	24,696	14,267	74,180	24,696	49,484
Retail propane and other retail propane related	1,704	12,236	(10,532)	90,499	154,591	(64,092)
All other	(9,059)	936	(9,995)	(2,546)	1,579	(4,125)
Total	466,350	388,135	78,215	1,002,412	859,434	142,978
Depreciation and amortization	(99,102)	(104,972)	5,870	(201,019)	(200,936)	(83)
Interest expense, net of interest capitalized	(134,310)	(116,466)	(17,844)	(271,130)	(223,706)	(47,424)
Gain on deconsolidation of Propane Business	765	—	765	1,056,709	—	1,056,709
Gains (losses) on non-hedged interest rate derivatives	(35,917)	2,111	(38,028)	(8,022)	3,890	(11,912)
Non-cash unit-based compensation expense	(10,283)	(10,600)	317	(20,992)	(20,789)	(203)
Allowance for equity funds used during construction	123	1,201	(1,078)	227	69	158
Unrealized gains (losses) on commodity risk management activities	14,652	562	14,090	(70,974)	7,654	(78,628)
Gains (losses) on disposal of assets	146	(528)	674	(878)	(2,254)	1,376
Loss on extinguishment of debt	—	—	—	(115,023)	—	(115,023)
Adjusted EBITDA attributable to noncontrolling interest	15,810	10,585	5,225	31,057	10,585	20,472
Proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	(96,623)	(8,251)	(88,372)	(141,110)	(15,721)	(125,389)
Other	2,200	622	1,578	2,774	1,972	802
Income before income tax expense	123,811	162,399	(38,588)	1,264,031	420,198	843,833
Income tax expense	(24)	(5,783)	5,759	(14,147)	(16,380)	2,233
Net income	$123,787	$156,616	$(32,829)	$1,249,884	$403,818	$846,066

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. For the three and six months ended June 30, 2012, depreciation and amortization decreased by approximately $19.7 million and $37.6 million due to the deconsolidation of the Propane Business in January 2012. These decreases were offset by additional depreciation recorded from assets placed in service.

Table of Contents

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 in January 2012.
Gains (Losses) on Non-Hedged Interest Rate Derivatives. During the three months ended June 30, 2012, forward rates decreased sharply which resulted in unrealized losses on our forward-starting floating-to-fixed swaps. For the six months ended June 30, 2012, the unrealized losses also reflect the offsetting impact of forward rate increases in the first quarter of 2012.
Income Tax Expense. The decrease 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.
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 for the six months ended June 30, 2012 in connection with our tender offers in which we repurchased approximately $750.0 million in aggregate principal amount of Senior Notes in January 2012.
Adjusted EBITDA Attributable to Noncontrolling Interest. These amounts represent 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.
Other. Includes other income and expense amounts, net and amortization of regulatory assets.
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.

Table of Contents

- 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.

Intrastate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Natural gas transported (MMBtu/d)	9,928,726	11,322,195	(1,393,469)	10,021,540	11,477,624	(1,456,084)
Revenues	$494,481	$672,494	$(178,013)	$976,534	$1,444,253	$(467,719)
Cost of products sold	272,897	440,570	(167,673)	587,068	973,200	(386,132)
Gross margin	221,584	231,924	(10,340)	389,466	471,053	(81,587)
Unrealized (gains) losses on commodity risk management activities	(15,034)	121	(15,155)	66,653	(6,710)	73,363
Operating expenses, excluding non-cash compensation expense	(46,961)	(49,496)	2,535	(85,864)	(95,295)	9,431
Selling, general and administrative expenses, excluding non-cash compensation expense	(2,827)	(10,930)	8,103	(21,629)	(25,430)	3,801
Adjusted EBITDA related to unconsolidated affiliates	186	(70)	256	591	746	(155)
Segment Adjusted EBITDA	$156,948	$171,549	$(14,601)	$349,217	$344,364	$4,853

Volumes. We experienced a decrease in transported volumes for both the three and six months ended June 30, 2012 compared to the same periods in the prior year due to an unfavorable natural gas price environment. The average spot price at Houston Ship Channel declined to $2.23/MMBtu and $2.32/MMBtu during the three and six months ended June 30, 2012, respectively, compared to $4.32/MMBtu and $4.21/MMBtu during the three and six months ended June 30, 2011, respectively.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Transportation fees	$137,356	$157,672	$(20,316)	$281,205	$300,338	$(19,133)
Natural gas sales and other	32,693	18,390	14,303	46,507	63,589	(17,082)
Retained fuel revenues	16,395	36,680	(20,285)	33,367	71,662	(38,295)
Storage margin, including fees	35,140	19,182	15,958	28,387	35,464	(7,077)
Total gross margin	$221,584	$231,924	$(10,340)	$389,466	$471,053	$(81,587)

Table of Contents

For the three months ended June 30, 2012 compared to the three months ended June 30, 2011, intrastate transportation and storage gross margin decreased primarily due to the following factors:

- Transportation fees decreased $20.3 million due to lower demand fees of $17.4 million primarily due to a change in a customer contract that impacted the timing of the recording of demand fees and an unfavorable impact of $3.8 million from a decline in transported volumes.
- Margin from sales of natural gas and other activities increased $14.3 million primarily due to favorable mark-to-market impacts from system optimization activities of $22.3 million offset by a decline of $11.4 million in margin where we utilize third party processing. We also experienced a $3.5 million decrease in natural gas costs compared to the same period 2011.

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 in addition to trading activities using financial commodity derivatives. Excluding derivatives related to storage, unrealized gains of $6.1 million were recorded during the three months ended June 30, 2012 compared to unrealized losses of $16.2 million during the three months ended June 30, 2011.

- 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 $20.3 million due to lower retained volumes of 0.9 Bcf and a decrease in natural gas prices as noted above.

For the six months ended June 30, 2012 compared to the six months ended June 30, 2011, intrastate transportation and storage gross margin decreased primarily due to the following factors:

- Transportation fees decreased $19.1 million primarily due to lower demand fees of $13.1 million primarily due to a change in a customer contract that impacted the timing of the recording of demand fees and an unfavorable impact of $6.5 million from a decline in transported volumes.
- Margin from sales of natural gas and other activities decreased $17.1 million primarily due to a decline of $18.1 million in margin related to the utilization of third-party processing.
- 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 $38.3 million due to lower retained volumes of 1.6 Bcf and a decrease in natural gas prices as noted above.

Storage margin was comprised of the following:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Withdrawals from storage natural gas inventory (MMBtu)	3,893,660	647,373	3,246,287	4,440,394	15,772,126	(11,331,732)
Margin on physical sales	$(7,079)	$179	$(7,258)	$(7,954)	$10,691	$(18,645)
Settlements of derivatives	25,906	(5,199)	31,105	87,465	571	86,894
Realized margin (loss) on natural gas inventory transactions	18,827	(5,020)	23,847	79,511	11,262	68,249
Fair value inventory adjustments	48,229	3,309	44,920	(2,072)	4,831	(6,903)
Unrealized gains (losses) on derivatives	(39,270)	12,750	(52,020)	(64,667)	1,793	(66,460)
Margin recognized on natural gas inventory and related derivatives	27,786	11,039	16,747	12,772	17,886	(5,114)
Revenues from fee-based storage	7,411	8,218	(807)	15,890	17,819	(1,929)
Other costs	(57)	(75)	18	(275)	(241)	(34)
Total storage margin	$35,140	$19,182	$15,958	$28,387	$35,464	$(7,077)

The increase in our storage margin for the three months ended June 30, 2012 compared to the three months ended June 30, 2011 was principally driven by an increase in inventory valuation and derivatives settled during the period due to a recent increase in prices and a larger inventory balance at June 30, 2012. The decrease in margin for the six months ended June 30, 2012 compared to the six months ended June 30, 2012 was due to fewer withdrawals given the price environment and a decline in fee-based revenue resulting from the cessation of 4.5 Bcf in fixed fee contracts in 2011.

Table of Contents

Unrealized Gains (Losses) 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 June 30, 2012 primarily due to the impacts of fair value accounting as prices increased during June 2012. During the three months ended June 30, 2012, we settled derivatives for a $27.1 million gain. We also recorded additional mark-to-market gains of $6.1 million in the three months ended June 30, 2012 related to non-storage derivatives.

Unrealized losses for the six months ended June 30, 2012 were primarily due to derivatives related to our stored natural gas. The impact of unrealized losses to storage margin was offset by realized derivative gains.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased during the three months ended June 30, 2012 principally due to a decrease in natural gas consumed for compression of $8.7 million offset by increases in electricity costs of $1.2 million, environmental expenses of $2.8 million and various other expenses of $2.3 million.

For the six months ended June 30, 2012, operating expenses decreased due to a decrease in natural gas consumed for compression of $13.0 million offset by increases in environmental expenses of $1.4 million, employee costs of $0.8 million and various other expenses of $1.6 million.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. For the three and six months ended June 30, 2012, intrastate transportation and storage selling, general and administrative expenses decreased as a result of a decrease in employee-related costs (including allocated overhead expenses).

Interstate Transportation

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Natural gas transported (MMBtu/d)	2,832,897	2,712,947	119,950	2,992,985	2,482,807	510,178
Natural gas sold (MMBtu/d)	17,770	22,158	(4,388)	19,144	22,868	(3,724)
Revenues	$126,900	$104,850	$22,050	$255,176	$209,951	$45,225
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(29,220)	(25,550)	(3,670)	(57,141)	(52,175)	(4,966)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(8,719)	(9,276)	557	(18,862)	(15,929)	(2,933)
Adjusted EBITDA related to unconsolidated affiliates	95,458	13,474	81,984	118,226	21,761	96,465
Segment Adjusted EBITDA	$184,419	$83,498	$100,921	$297,399	$163,608	$133,791

Volumes. Transported volumes increased for the three and six months ended June 30, 2012 compared to the same periods in the prior year primarily due to additional transported volumes related to the expansion of Tiger pipeline which went in service August 2011. Operational sales volumes decreased in the Transwestern pipeline principally as a result of unfavorable market conditions.

Revenues. Interstate transportation revenues increased compared to the same periods in the prior year as a result of $29.2 million and $59.4 million in incremental reservation fees resulting from increased contractual commitments related to the Tiger pipeline expansion for the three and six months ended June 30, 2012, respectively. The increases for the three and six months ended June 30, 2012 were partially offset by decreased revenues 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, Amortization and Accretion Expenses. Interstate transportation operating expenses increased during the three and six months ended June 30, 2012 compared to the same periods in the prior year primarily due to increases in property taxes related to Tiger's expansion project.

Table of Contents

Selling, General and Administrative, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation selling, general and administrative expenses increased during the six months ended June 30, 2012 compared to the same period in the prior year primarily due to higher allocated corporate and pipeline costs, outside services and employee-related costs primarily during the first three months of 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates. Interstate transportation Adjusted EBITDA from unconsolidated affiliates increased for the three and six months ended June 30, 2012 compared to the same periods in the prior year primarily due to increases of $5.0 million and $15.3 million, respectively, in Adjusted EBITDA from FEP. In addition, Adjusted EBITDA from unconsolidated affiliates reflects the results of our investment in Citrus subsequent to our acquisition of a 50% interest in Citrus on March 26, 2012. For the three and six months ended June 30, 2012, Adjusted EBITDA attributable to Citrus was $77.0 million and $81.3 million, respectively.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Gathered volumes (MMBtu/d)	2,450,673	2,080,027	370,646	2,424,862	2,003,745	421,117
NGLs produced (Bbls/d)	82,807	50,728	32,079	74,474	50,243	24,231
Equity NGLs produced (Bbls/d)	22,744	17,137	5,607	20,413	16,519	3,894
Revenues	$556,654	$617,935	$(61,281)	$1,111,212	$1,269,191	$(157,979)
Cost of products sold	421,578	490,854	(69,276)	846,606	1,039,197	(192,591)
Gross margin	135,076	127,081	7,995	264,606	229,994	34,612
Unrealized (gains) losses on commodity risk management activities	(245)	(673)	428	2,167	(1,172)	3,339
Operating expenses, excluding non-cash compensation expense	(28,656)	(24,696)	(3,960)	(56,867)	(49,103)	(7,764)
Selling, general and administrative expenses, excluding non-cash compensation expense	(12,800)	(6,492)	(6,308)	(16,243)	(9,123)	(7,120)
Segment Adjusted EBITDA	$93,375	$95,220	$(1,845)	$193,663	$170,596	$23,067

Volumes. NGL production increased during the three and six months ended June 30, 2012 primarily due to increased inlet volumes at our La Grange and Chisolm plants as a result of increased capacity and more production in the Eagle Ford Shale offset by reduced inlet volumes at our Godley plant as a result of lower production in the Barnett Shale. The increase in equity NGL production was primarily due to higher overall production which was offset by a higher concentration of volumes under fee-based contracts during the three and six months ended June 30, 2012 as compared to the same periods last year.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Gathering and processing fee-based revenues	$82,048	$65,989	$16,059	$157,949	$125,596	$32,353
Non fee-based contracts and processing	58,679	64,579	(5,900)	119,185	110,949	8,236
Other	(5,651)	(3,487)	(2,164)	(12,528)	(6,551)	(5,977)
Total gross margin	$135,076	$127,081	$7,995	$264,606	$229,994	$34,612

For the three months ended June 30, 2012, midstream gross margin increased compared to the same period last year due to the following:

- Increased volumes, primarily as a result of increased capacity from growth projects in the Eagle Ford Shale, resulted in an increase in fee-based revenues of $16.1 million.

Table of Contents

- Our non-fee-based gross margins decreased $5.9 million primarily due to lower NGL prices offset by higher equity NGL volumes resulting from increased capacity from growth projects in the Eagle Ford Shale. The composite NGL price decreased during the three months ended June 30, 2012 to $0.94 per gallon from $1.33 per gallon during the same period last year.

For the six months ended June 30, 2012, midstream gross margin increased compared to the same period last year due to the following:

- Increased volumes, primarily as a result of increased capacity from growth projects in the Eagle Ford Shale, resulted in an increase in fee-based revenues of $32.4 million.

- Our non-fee-based gross margins increased $8.2 million primarily due to higher equity NGL volumes resulting from increased capacity from growth projects in the Eagle Ford Shale offset by lower NGL prices.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized gains of $0.2 million during the three months ended June 30, 2012 compared to unrealized gains of $0.7 million in the same period last year. For the six months ended June 30, 2012, we recorded unrealized losses of $2.2 million compared to unrealized gains of $1.2 million in the same period last year. These changes were due to less favorable prices.

Operating Expenses, Excluding Non-Cash Compensation Expense. Increases in midstream operating expenses for the three and six months ended June 30, 2012 compared to the same periods in the prior year were primarily attributable to incremental operating expenses from new assets placed into service in the Eagle Ford Shale. Midstream operating expenses increased for the three months ended June 30, 2012 compared to the same period in the prior year due to an increase in operating expenses of $1.3 million, an increase in maintenance expenses of $1.1 million, an increase in ad valorem taxes of $1.1 million and an increase in employee related costs of $0.5 million. For the six months ended June 30, 2012 compared to the same period in the prior year, midstream operating expenses increased primarily due to an increase in ad valorem taxes of $3.6 million, an increase in operating expenses of $2.2 million, an increase in maintenance expenses of $1.1 million and an increase in employee related costs of $0.9 million.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased for the three and six months ended June 30, 2012 compared to the same periods in the prior year primarily due to increases in employee related costs.

NGL Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
NGL transportation volumes (Bbls/d)	175,591	128,127	47,464	163,531	128,127	35,404
NGL fractionation volumes (Bbls/d)	21,204	15,658	5,546	20,606	15,658	4,948
Revenues	$160,477	$98,820	$61,657	$328,028	$98,820	$229,208
Cost of products sold	85,341	52,404	32,937	183,988	52,404	131,584
Gross margin	75,136	46,416	28,720	144,040	46,416	97,624
Operating expenses, excluding non-cash compensation expense	(16,334)	(6,487)	(9,847)	(29,970)	(6,487)	(23,483)
Selling, general and administrative expenses, excluding non-cash compensation expense	(5,126)	(4,648)	(478)	(10,191)	(4,648)	(5,543)
Adjusted EBITDA related to unconsolidated affiliates	1,097	—	1,097	1,358	—	1,358

Adjusted EBITDA attributable to noncontrolling interest	(15,810)	(10,585)	(5,225)	(31,057)	(10,585)	(20,472)
Segment Adjusted EBITDA	$38,963	$24,696	$14,267	$74,180	$24,696	$49,484

Table of Contents

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 were recently placed in service.
Volumes. The volumes reflected above for the three and six months ended June 30, 2011 represent average daily volumes for the period from May 2, 2011 to June 30, 2011. NGL transportation volumes increased for the three and six month ended June 30, 2012 as compared to the three and six month ended June 30, 2011 primarily due to an increase in volumes transported on our wholly-owned NGL pipelines originating from our La Grange and Chisholm plants as a result of more production in the Eagle Ford area. Additionally, fractionation volumes increased for the three and six months ended June 30, 2012 as compared to the three and six months ended June 30, 2011 due to increased production at our Geismar, Louisiana fractionation complex as a result of less refinery downtime for turnarounds during the three and six months ended June 30, 2012.
Gross Margin. The components of our NGL transportation and services segment gross margin were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Storage margin	$30,560	$23,414	7,146	$62,192	$23,414	$38,778
Transportation fees	17,677	7,051	10,626	30,749	7,051	23,698
Processing and fractionation margin	26,904	16,722	10,182	51,105	16,722	34,383
Other margin	(5)	(771)	766	(6)	(771)	765
Total gross margin	$75,136	$46,416	$28,720	$144,040	$46,416	$97,624

Retail Propane and Other Retail Propane Related

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Change	2012	2011	Change
Retail propane gallons (in thousands)	3,328	84,161	(80,833)	29,720	288,301	(258,581)
Revenues	$11,637	$220,296	$(208,659)	$87,082	$748,762	$(661,680)
Other retail propane related revenues	1,329	23,677	(22,348)	5,890	52,426	(46,536)
Cost of products sold	7,325	139,472	(132,147)	56,027	454,892	(398,865)
Gross margin	5,641	104,501	(98,860)	36,945	346,296	(309,351)
Unrealized (gains) losses on commodity risk management activities	1,320	(10)	1,330	3,318	228	3,090
Operating expenses, excluding non-cash compensation expense	(5,615)	(79,134)	73,519	(23,604)	(166,726)	143,122
Selling, general and administrative expenses, excluding non-cash compensation expense	198	(13,121)	13,319	(1,256)	(25,207)	23,951
Adjusted EBITDA related to unconsolidated affiliates	160	—	160	75,096	—	75,096
Segment Adjusted EBITDA	$1,704	$12,236	$(10,532)	$90,499	$154,591	$(64,092)

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, 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 six months ended June 30, 2012. For the three and six months ended June 30, 2012, the retail propane and other retail propane related segment data presented above also included our equity investment in AmeriGas. We recorded equity in losses related to AmeriGas of $36.4 million and equity in earnings of $3.1 million for the three and six months ended June 30, 2012, respectively.

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 $450.0 million and $500.0 million for the remainder of 2012;
- growth capital expenditures for our NGL transportation and services segment of between $700.0 million and $800.0 million 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 $200.0 million and $250.0 million; and
- maintenance capital expenditures of between $50.0 million and $60.0 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.

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.

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 for the next 12 months; 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.

We anticipate utilizing our revolving credit facility to fund cash requirements, including the net cash that will be required to complete the Sunoco Acquisition. However, we expect to continue to prudently raise debt and equity to fund our growth capital requirements, to maintain sufficient liquidity, and to manage our credit metrics in order to maintain our investment grade credit ratings.

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 inventories, and the timing of advances and deposits received from customers.

Six months ended June 30, 2012 compared to six months ended June 30, 2011. Cash provided by operating activities during 2012 was $599.5 million as compared to $639.4 million for 2011 and net income was $1.25 billion and $403.8 million for 2012 and 2011, respectively. The difference between net income and cash provided by operating activities for the six months ended June 30, 2012 primarily consisted of the gain on the deconsolidation of propane of $1.06 billion and changes in operating assets and liabilities of $58.6 million, offset by the loss on extinguishment of debt of $115.0 million and non-cash items totaling $236.8

million. The difference between net income and cash provided by operating activities for the six months ended June 30, 2011 primarily consisted of non-cash items totaling $229.9 million and changes in operating assets and liabilities of $7.5 million.

The non-cash activity in 2012 and 2011 consisted primarily of depreciation and amortization of $201.0 million and $200.9 million, respectively. In addition, non-cash compensation expense was $21.0 million and $20.8 million for 2012 and 2011, respectively.

Cash paid for interest, net of interest capitalized, was $221.9 million and $216.1 million for the six months ended June 30, 2012 and 2011, respectively.

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.

Six months ended June 30, 2012 compared to six months ended June 30, 2011. Cash used in investing activities during 2012 was $1.40 billion as compared to $2.58 billion for 2011. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2012 were $1.02 billion, including changes in accruals of $263.6 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2011 of $621.9 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 $1.44 billion from the contribution of the Propane Business. In 2011 we paid cash for acquisitions of $1.95 billion, primarily for the acquisition of LDH (the “LDH Acquisition”), and made net advances to our joint ventures of $22.7 million.

Growth capital expenditures for 2012, before changes in accruals, were $1.22 billion for our midstream, intrastate transportation and storage and NGL segments, $3.5 million for our interstate transportation segment, and $1.9 million for our retail propane and all other segments. We also incurred $54.3 million in maintenance capital expenditures, of which $33.3 million related to our midstream, intrastate transportation and storage and NGL segments, $16.2 million related to our interstate transportation segment and $4.8 million related to our retail propane and all other segments.

Growth capital expenditures for 2011, before changes in accruals, were $433.6 million for our midstream and intrastate transportation and storage segments, $117.7 million for our interstate transportation segment, and $16.0 million for our retail propane and all other segments. We also incurred $49.1 million in maintenance capital expenditures, of which $29.6 million related to our midstream and intrastate transportation and storage segments, $9.4 million related to our interstate transportation segment and $10.1 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.

Six months ended June 30, 2012 compared to six months ended June 30, 2011. Cash provided by financing activities during 2012 was $883.1 million as compared to cash provided by financing activities of $2.02 billion for 2011. In 2012, we received net proceeds from Common Unit offerings of $93.6 million compared to $770.2 million 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 $1.30 billion as compared to a net increase of $1.24 billion for 2011, primarily due to our issuance of $2.00 billion in aggregate principal amount of senior notes in January 2012 to fund the Citrus Merger, partially offset by the repurchase of $750.0 million in aggregate 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 compared to $12.3 million in debt issuance costs in 2011 related to the issuance of senior notes in May 2011. We paid distributions of $628.2 million to our partners in 2012 as compared to $568.6 million in 2011. In addition, we received capital contributions of $151.2 million from Regency for its noncontrolling interest in Lone Star as compared to $591.7 million in 2011.

Table of Contents

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	June 30, 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	493,449	314,438
Other long-term debt	—	10,345
Unamortized discounts	(20,847)	(15,457)
Fair value adjustments related to interest rate swaps	8,841	11,647
Total debt	9,151,443	7,812,287
Less: current maturities	(108,050)	(424,117)
Long-term debt, less current maturities	$9,043,393	$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 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. Indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

As of June 30, 2012, we had $493.4 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.98 billion after taking into account letters of credit of $30.3 million. The weighted average interest rate on the total amount outstanding as of June 30, 2012 was 1.74%.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the acquisition of our Propane Business 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 acquisition of our Propane Business, 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 June 30, 2012.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of June 30, 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	$9,163,449	$108,050	$729,947	$1,368,449	$6,957,003
Interest on long-term debt (a)	4,975,082	224,879	845,313	709,139	3,195,751
Payments on derivatives	149,645	9,091	140,554	—	—
Purchase commitments (b)	117,813	116,423	1,390	—	—
Operating lease obligations	227,600	9,501	35,343	32,767	149,989

Totals (c)	$14,633,589	$467,944	$1,752,547	$2,110,355	$10,302,743

43

Table of Contents

(a) Interest payments on long-term debt are based on the principal amount of debt obligations as of June 30, 2012. With respect to variable rate debt, the interest payments were estimated using the interest rate as of June 30, 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 June 30, 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 $142.3 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
June 30, 2012	August 6, 2012	August 14, 2012	0.89375

The total amounts of distributions declared during the six months ended June 30, 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):

	Six Months Ended June 30,	
	2012	2011
Limited Partners:		
Common Units	$424,484	$372,970
Class E Units	6,242	6,242
General Partner interest	9,833	9,792
IDRs	206,678	206,540
Total distributions declared	$647,237	$595,544

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to approximately $220.0 million of the IDRs from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters. Accordingly, the distributions reflected above for the six months ended June 30, 2012 reflect IDR reductions totaling $27.5 million.

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.

Table of Contents

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. 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. Unless there is a ruling on a pending legal proceeding seeking to enjoin those rules, the CFTC's position limits will become effective 60 days after the CFTC publishes its final swap definition rule. Based on the CFTC's public statements, the expected publication date of that rule is August 13, 2012, which would result in an October 12, 2012 compliance date for the CFTC's position limits. The 60-day period following publication of the swap definition rule also triggers the start of certain reporting and recordkeeping rules, with full compliance phased in over an additional 180-day period depending on swap asset class and counterparty. 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.

Table of Contents

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of June 30, 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.

	June 30, 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]	7,650,000	$(15,822)	$ 196	(151,260,000)	$(22,582)	$ 2,593
Power:						
Forwards	4,800	1,061	863	—	—	—
Options – Puts	36,800	104	10	—	—	—
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(55,272,500)	(3,018)	23	(61,420,000)	4,024	266
Swing Swaps IFERC	(19,825,000)	(1,914)	28	92,370,000	(1,072)	138
Fixed Swaps/Futures	1,062,500	3,607	536	797,500	(4,301)	145
Forward Physical Contracts	(20,481,365)	589	1,866	(10,672,028)	(13)	1,118
Options – Puts	500,000	(55)	—	—	—	—
Propane:						
Forwards/Swaps	—	—	—	38,766,000	(4,122)	5,290
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(25,707,500)	(630)	103	(28,752,500)	(808)	181
Fixed Swaps/Futures	(51,790,000)	(3,542)	17,474	(45,822,500)	70,761	14,048
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(12,850,000)	(369)	42	—	—	—
Fixed Swaps/Futures	(31,100,000)	7,067	10,565	—	—	—
Options – Puts	1,800,000	3,688	506	3,600,000	6,435	933
Options – Calls	(1,800,000)	(1)	—	(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

Table of Contents

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.

Interest Rate Risk

As of June 30, 2012, we had $493.4 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 $4.9 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 June 30, 2012 and December 31, 2011 (dollars in thousands), none of which are designated as hedges for accounting purposes:

Term	Type [1]	Notional Amount Outstanding	
		June 30, 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 $85.2 million as of June 30, 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.

Table of Contents

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.

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 June 30, 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 June 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Table of Contents

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 June 30, 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 and "Part II — Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.

Risks Relating to the Sunoco Merger and the Holdco Restructuring

Our acquisition of Sunoco and the Holdco restructuring are subject to the satisfaction of certain conditions to closing.

Our acquisition of Sunoco is subject to the satisfaction of certain conditions to closing, including the adoption of the Sunoco merger agreement by the shareholders of Sunoco, the receipt of required regulatory approvals, the effectiveness of a registration statement on Form S-4 relating to the ETP Common Units to be issued in connection with the merger, and the absence of any law, injunction, judgment or ruling prohibiting or restraining the Sunoco merger or making the consummation of the Sunoco merger illegal. In the event those conditions to closing are not satisfied or waived, we would not complete the acquisition of Sunoco.

Additionally, the Holdco restructuring is subject to the satisfaction of certain conditions to closing, including the closing of the Sunoco merger. We cannot predict with certainty whether and when these conditions will be satisfied. Any delay in completing the merger, and thereby the Holdco restructuring, could cause us not to realize, or delay the realization, of some or all of the benefits of the Sunoco merger and the Holdco restructuring.

Any acquisition we complete, including the 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.

Any acquisition we complete, including the proposed Sunoco acquisition, 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;
- the validity of our assessment of environmental liabilities, including legacy liabilities;
- a significant 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 or 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 other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

Table of Contents

If we consummate future acquisitions, our capitalization and results of operations may change significantly. As we determine the application of our funds and other resources, unitholders will not have an opportunity to evaluate the economics, financial and other relevant information that we will consider.

Also, 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 and the Holdco restructuring may 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 agreement requires that we pay Sunoco shareholders a combination of cash and ETP Common Units as consideration for Sunoco common shares. We plan to fund the cash payment partially with Sunoco's cash on hand and with borrowings under our amended and restated revolving credit facility. The incurrence of this additional indebtedness will increase our overall level of debt and adversely affect our ratios of total indebtedness to EBITDA and EBITDA to interest expense, both on a current basis and a pro forma basis taking into account our merger with Sunoco. As of June 30, 2012, our unaudited pro forma condensed consolidated long-term debt (including current maturities) after giving effect to the Sunoco merger and the Holdco restructuring would have been approximately $15.5 billion. If we are unable to finance the cash portion of the consideration for the Sunoco merger with borrowings under our amended and restated revolving credit facility, 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 agreement.

Pending litigation against us and Sunoco could result in an injunction preventing completion of the merger, the payment of damages in the event the 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 shareholders of Sunoco have filed several shareholder class action lawsuits against us, Sunoco, the Sunoco board of directors and others. Among other remedies, the plaintiffs seek 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 us and Sunoco, including any costs associated with the indemnification of directors. Additional lawsuits may be filed against us and/or Sunoco related to the Sunoco merger. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition or results of operations.

Failure to successfully combine our businesses and the businesses of Sunoco in the expected time frame may adversely affect our future results, which may adversely affect the value of our Common Units that Sunoco shareholders would receive in the Sunoco merger.

The success of the Sunoco merger will depend, in part, on our ability to realize the anticipated benefits from combining our businesses with the businesses of Sunoco. To realize these anticipated benefits, our and Sunoco's businesses must be successfully combined. If the combined company is not able to achieve these objectives, the anticipated benefits of the 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 merger.

We and Sunoco, including our respective subsidiaries, have operated and, until the completion of the 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 the combined company's ability to maintain relationships with customers and employees after the merger or to achieve the anticipated benefits of the 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 us and Sunoco.

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

None.

Table of Contents

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

ITEM 5. OTHER INFORMATION

None.

Table of Contents

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	Agreement and Plan of Merger, dated as of April 29, 2012 by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc. and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P.
(3)	2.2	Transaction Agreement, dated as of June 15, 2012, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage Holdings, Inc., Energy Transfer Equity, L.P., ETE Sigma Holdco, LLC and ETE Holdco Corporation.
(4)	2.3	Amendment No. 1, dated as of June 15, 2012, to the Agreement and Plan of Merger, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc., and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P.
(2)	10.1	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(*)	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.

(1) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on May 1, 2012.
(2) Incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on May 1, 2012.
(3) Incorporated by reference to Exhibit 2.1 to 2.3 to Registrant's Form 8-K filed on June 20, 2012.
(4) Incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed on June 20, 2012.

Table of Contents

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: August 8, 2012	By: /s/ Martin Salinas, Jr. Martin Salinas, Jr. Chief Financial Officer (duly authorized to sign on behalf of the registrant)