Energy Transfer Partners, L.P.
Form 10-Q
May 09, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended March 31, 2013

or

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

Commission file number 1-11727

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

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

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

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

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

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

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

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

At May 1, 2013, the registrant had units outstanding as follows:
Energy Transfer Partners, L.P. 369,501,191 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 I — Item 1A. Risk Factors” in the Partnership’s Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission on March 1, 2013.

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)
AROs	asset retirement obligations
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
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
Citrus	Citrus Corp.
CrossCountry	CrossCountry Energy, LLC
DOT	U.S. Department of Transportation
ETC Compression	ETC Compression, LLC
ETC FEP	ETC Fayetteville Express Pipeline, LLC

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

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
Holdco	ETP Holdco Corporation
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
MTBE	methyl tertiary butyl ether
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
Panhandle	Panhandle Eastern Pipe Line Company, LP
PCBs	polychlorinated biphenyls
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
SUGS	Southern Union Gas Services

Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas 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 based on 100% of the subsidiaries' results of operations and for unconsolidated affiliates based on the Partnership's 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 millions)
(unaudited)

	March 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$528	$311
Accounts receivable, net	3,527	2,910
Accounts receivable from related companies	142	94
Inventories	1,631	1,495
Exchanges receivable	44	55
Price risk management assets	27	21
Current assets held for sale	136	184
Other current assets	324	334
Total current assets	6,359	5,404
PROPERTY, PLANT AND EQUIPMENT	27,888	27,412
ACCUMULATED DEPRECIATION	(1,881)	(1,639)
	26,007	25,773
NON-CURRENT ASSETS HELD FOR SALE	992	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,489	3,502
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	35	42
GOODWILL	5,586	5,606
INTANGIBLE ASSETS, net	1,544	1,561
OTHER NON-CURRENT ASSETS, net	356	357
Total assets	$44,368	$43,230

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

1

Table of Contents

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

	March 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$3,468	$3,002
Accounts payable to related companies	27	24
Exchanges payable	170	156
Price risk management liabilities	99	110
Accrued and other current liabilities	1,333	1,562
Current maturities of long-term debt	606	609
Current liabilities held for sale	80	85
Total current liabilities	5,783	5,548
NON-CURRENT LIABILITIES HELD FOR SALE	142	142
LONG-TERM DEBT, less current maturities	16,135	15,442
LONG-TERM NOTES PAYABLE — RELATED PARTY	166	166
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	124	129
DEFERRED INCOME TAXES	3,541	3,476
OTHER NON-CURRENT LIABILITIES	1,008	995
COMMITMENTS AND CONTINGENCIES (Note 12)		
EQUITY:		
General Partner	194	188
Limited Partners:		
Common Unitholders	9,151	9,026
Accumulated other comprehensive loss	(5)	(13)
Total partners’ capital	9,340	9,201
Noncontrolling interest	8,129	8,131
Total equity	17,469	17,332
Total liabilities and equity	$44,368	$43,230

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 OPERATIONS
(Dollars in millions, except per unit data)
(unaudited)

	Three Months Ended March 31,	
	2013	2012
REVENUES:		
Natural gas sales	$874	$423
NGL sales	589	369
Crude sales	3,201	—
Gathering, transportation and other fees	637	393
Refined product sales	4,662	—
Other	891	138
Total revenues	10,854	1,323
COSTS AND EXPENSES:		
Cost of products sold	9,594	781
Operating expenses	304	130
Depreciation and amortization	260	99
Selling, general and administrative	162	104
Total costs and expenses	10,320	1,114
OPERATING INCOME	534	209
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(211)	(141)
Equity in earnings of unconsolidated affiliates	72	55
Gain on deconsolidation of Propane Business	—	1,056
Loss on extinguishment of debt	—	(115)
Gains on interest rate derivatives	7	28
Other, net	3	(1)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	405	1,091
Income tax expense from continuing operations	3	2
INCOME FROM CONTINUING OPERATIONS	402	1,089
Income (loss) from discontinued operations	22	(1)
NET INCOME	424	1,088
LESS: NET INCOME (LOSS) ATTRIBUTABLE TO NONCONTROLLING INTEREST	102	(27)
NET INCOME ATTRIBUTABLE TO PARTNERS	322	1,115
GENERAL PARTNER’S INTEREST IN NET INCOME	128	117
LIMITED PARTNERS’ INTEREST IN NET INCOME	$194	$998
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:		
Basic	$0.60	$4.37
Diluted	$0.60	$4.36
NET INCOME PER LIMITED PARTNER UNIT:		
Basic	$0.63	$4.36
Diluted	$0.63	$4.35

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 millions)
(unaudited)

	Three Months Ended March 31,	
	2013	2012
Net income	$424	$1,088
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(1)	(3)
Change in value of derivative instruments accounted for as cash flow hedges	2	20
Change in value of available-for-sale securities	1	—
Actuarial loss relating to pension and other postretirement benefits	(1)	—
Foreign currency translation adjustment	(1)	—
Change in other comprehensive income from equity investments	7	—
	7	17
Comprehensive income	431	1,105
Less: Comprehensive income attributable to noncontrolling interest	101	11
Comprehensive income attributable to partners	$330	$1,094

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 THREE MONTHS ENDED MARCH 31, 2013
(Dollars in millions)
(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2012	$188	$9,026	$(13)	$8,131	$17,332
Distributions to partners	(122)	(269)	—	—	(391)
Distributions to noncontrolling interest	—	—	—	(132)	(132)
Units issued for cash	—	192	—	—	192
Capital contributions from noncontrolling interest	—	—	—	27	27
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	10	—	3	13
Other comprehensive income (loss), net of tax	—	—	8	(1)	7
Other, net	—	(2)	—	(1)	(3)
Net income	128	194	—	102	424
Balance, March 31, 2013	$194	$9,151	$(5)	$8,129	$17,469

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 millions)
(unaudited)

	Three Months Ended March 31,	
	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$424	$1,088
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	260	99
Deferred income taxes	8	(2)
Gain on curtailment of other postretirement benefits	—	(15)
Amortization of finance costs charged to interest	(23)	3
Loss on extinguishment of debt	—	115
LIFO valuation adjustment	(38)	—
Non-cash compensation expense	14	11
Gain on deconsolidation of Propane Business	—	(1,056)
Distributions on unvested awards	(3)	(2)
Equity in earnings of unconsolidated affiliates	(72)	(55)
Distributions from unconsolidated affiliates	80	37
Other non-cash	6	4
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation (see Note 4)	(303)	(167)
Net cash provided by operating activities	353	60
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for Citrus Acquisition	—	(1,895)
Cash proceeds from contribution and sale of propane operations	—	1,384
Cash received from all other acquisitions	—	472
Capital expenditures (excluding allowance for equity funds used during construction)	(595)	(521)
Contributions in aid of construction costs	8	6
Contributions to unconsolidated affiliates	(1)	(2)
Distributions from unconsolidated affiliates in excess of cumulative earnings	15	5
Proceeds from the sale of assets	10	13
Other	4	—
Net cash used in investing activities	(559)	(538)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	2,563	2,779
Repayments of long-term debt	(1,835)	(2,048)
Net proceeds from issuance of Limited Partner units	192	87
Capital contributions received from noncontrolling interest	42	67
Distributions to partners	(391)	(318)
Distributions to noncontrolling interest	(132)	(7)
Debt issuance costs	(16)	(20)
Net cash provided by financing activities	423	540
INCREASE IN CASH AND CASH EQUIVALENTS	217	62
CASH AND CASH EQUIVALENTS, beginning of period	311	107
CASH AND CASH EQUIVALENTS, end of period	$528	$169

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

6

Table of Contents

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

In accordance with GAAP, we have accounted for the Holdco Transaction, whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union).

Business Operations

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

- ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia. Our intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern’s revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus, 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.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of refined products and crude oil pipelines, terminalling and storage assets, and refined products and crude oil acquisition and marketing assets.
- Holdco, a Delaware limited liability company that directly owns Southern Union and Sunoco. As discussed in Note 3, ETP acquired ETE’s 60% interest in Holdco on April 30, 2013. Sunoco and Southern Union operations are described as follows:
- Southern Union owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the gathering, processing, transportation, storage and distribution of natural gas in the United States. As discussed in Note 3, on April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS.
- Sunoco owns and operates retail marketing assets, which sell gasoline and middle distillates at retail and operates convenience stores primarily on the east coast and in the midwest region of the United States.

7

Table of Contents

Our financial statements reflect the following reportable business segments:

- intrastate natural gas transportation and storage;
- interstate natural gas transportation and storage;
- midstream;
- NGL transportation and services;
- investment in Sunoco Logistics; and
- retail marketing.

Preparation of Interim Financial Statements

The accompanying consolidated balance sheet as of December 31, 2012, which has been derived from audited financial statements, and the unaudited interim consolidated financial statements and notes thereto of the Partnership as of March 31, 2013 and for the three month periods ended March 31, 2013 and 2012, have been prepared in accordance with GAAP for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership's operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

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 March 31, 2013, and the Partnership's results of operations and cash flows for the three months ended March 31, 2013 and 2012. 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, 2012, as filed with the SEC on March 1, 2013.

Certain prior period amounts have been reclassified to conform to the 2013 presentation. These reclassifications had no impact on net income or total equity.

2. ESTIMATES:

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

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for 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 goodwill impairment tests, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual values and results could differ from those estimates.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

Sale of Distribution Operations

In December 2012, Southern Union entered into definitive purchase and sale agreements dated December 14, 2012 (collectively, the "Purchase and Sale Agreements") with each of Plaza Missouri Acquisition, Inc. ("Laclede Missouri") and Plaza Massachusetts Acquisition, Inc. ("Laclede Massachusetts"), both of which are subsidiaries of The Laclede Group, Inc., pursuant to which Laclede Missouri has agreed to acquire the assets of Southern Union's Missouri Gas

Energy division, and Laclede Massachusetts has agreed to acquire the assets of Southern Union’s New England Gas Company division. Total consideration for the acquisitions will be $1.04 billion, subject to customary closing adjustments, less the assumption of $19

8

Table of Contents

million of debt. On February 11, 2013, the Laclede Entities announced that it had entered into an agreement with Algonquin Power & Utilities Corp ("APUC") that will allow a subsidiary of APUC to assume the right of the Laclede Entities to purchase the assets of Southern Union's New England Gas Company division, subject to certain approvals. The transactions contemplated by the Purchase and Sale Agreements are expected to close by the end of the third quarter of 2013.

For the three months ended March 31, 2013 and the period from March 26, 2012 to March 31, 2012, the distribution operations have been classified as discontinued operations in the consolidated statements of operations. The assets and liabilities of the disposal group have been classified as assets and liabilities held for sale as of March 31, 2013 and December 31, 2012.

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The total cash consideration was reduced by $107 million of estimated closing adjustments. In addition, PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the Contribution Agreement. The Regency Class F units have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis. Upon the closing of the transaction, ETE agreed to forego all distributions with respect to its IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing.

Acquisition of ETE's Holdco Interest

On April 30, 2013, ETP acquired from ETE its interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of estimated closing adjustments. ETE, which owns the general partner and IDRs of ETP, has agreed to forego all of the IDR payments on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurs, and 50% of the IDR payments on the newly issued ETP units for the following eight consecutive quarters. As a result, ETP now owns 100% of Holdco. As this transaction occurred subsequent to March 31, 2013, the Partnership's consolidated historical results of operations, cash flows and financial position as of and for the quarter ended March 31, 2013 were not affected by this transaction.

Sunoco Merger

On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly owned subsidiary of ETP, completed its merger with Sunoco. Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 55 million ETP Common Units and $2.6 billion in cash.

Management is continuing to validate certain assumptions made in connection with the purchase price allocation of Sunoco; therefore, certain assets and/or liabilities may be adjusted in future periods.

4. CASH AND CASH EQUIVALENTS:

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

Table of Contents

The net change in operating assets and liabilities included in cash flows from operating activities is comprised as follows:

	Three Months Ended March 31, 2013	2012
Accounts receivable	$(659)	$(55)
Accounts receivable from related companies	(48)	(58)
Inventories	(48)	22
Exchanges receivable	11	7
Other current assets	36	55
Other non-current assets, net	(6)	(41)
Accounts payable	435	(15)
Accounts payable to related companies	3	76
Exchanges payable	14	(11)
Accrued and other current liabilities	(35)	(179)
Other non-current liabilities	17	(14)
Price risk management assets and liabilities, net	(23)	46
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation	$(303)	$(167)

Non-cash investing and financing activities are as follows:

	Three Months Ended March 31, 2013	2012
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$372	$209
AmeriGas limited partner interests received in exchange for contribution of Propane Business	$—	$1,123
NON-CASH FINANCING ACTIVITIES:		
Contributions receivable related to noncontrolling interest	$8	$—
Issuance of common units in connection with acquisitions	$—	$105

5. INVENTORIES:

Inventories consisted of the following:

	March 31, 2013	December 31, 2012
Natural gas and NGLs	$223	$334
Crude oil	644	418
Refined products	588	572
Appliances, parts and fittings and other	176	171
Total inventories	$1,631	$1,495

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 is recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

Table of Contents

6. FAIR VALUE MEASUREMENTS:

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

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations. During the period ended March 31, 2013, no transfers were made between any levels within the fair value hierarchy.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value of our consolidated debt obligations at March 31, 2013 and December 31, 2012 was $18.35 billion and $17.84 billion, respectively. As of March 31, 2013 and December 31, 2012, the aggregate carrying amount of our consolidated debt obligations was $16.91 billion and $16.22 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

Table of Contents

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of March 31, 2013 and December 31, 2012 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at March 31, 2013	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$51	$—	$51
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	7	7	—
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	108	99	9
Forward Physical Swaps	1	—	1
Power:			
Forwards	3	—	3
Options — Calls	4	—	4
Natural Gas Liquids — Forwards/Swaps	7	7	—
Refined Products — Futures	2	2	—
Total commodity derivatives	133	115	18
Total Assets	$184	$115	$69
Liabilities:			
Interest rate derivatives	$(213)	$—	$(213)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(12)	(12)	—
Swing Swaps IFERC	(1)	—	(1)
Fixed Swaps/Futures	(113)	(111)	(2)
Options — Calls	(1)	—	(1)
Power:			
Forwards	(1)	—	(1)
Futures	(1)	(1)	—
Options — Calls	(1)	—	(1)
Natural Gas Liquids — Forwards/Swaps	(4)	(4)	—
Refined Products — Futures	(1)	(1)	—
Crude	(1)	(1)	—
Total commodity derivatives	(136)	(130)	(6)
Total Liabilities	$(349)	$(130)	$(219)

Table of Contents

	Fair Value Total	Fair Value Measurements at December 31, 2012	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$55	$—	$55
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	11	11	—
Swing Swaps IFERC	3	—	3
Fixed Swaps/Futures	96	94	2
Options — Puts	1	—	1
Options — Calls	3	—	3
Forward Physical Swaps	1	—	1
Power:			
Forwards	27	—	27
Futures	1	1	—
Options — Calls	2	—	2
Natural Gas Liquids — Swaps	1	1	—
Refined Products	5	1	4
Total commodity derivatives	151	108	43
Total Assets	$206	$108	$98
Liabilities:			
Interest rate derivatives	$(223)	$—	$(223)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(18)	(18)	—
Swing Swaps IFERC	(2)	—	(2)
Fixed Swaps/Futures	(103)	(94)	(9)
Options — Puts	(1)	—	(1)
Options — Calls	(3)	—	(3)
Power:			
Forwards	(27)	—	(27)
Futures	(2)	(2)	—
Natural Gas Liquids — Swaps	(3)	(3)	—
Refined Products	(8)	(1)	(7)
Total commodity derivatives	(167)	(118)	(49)
Total Liabilities	$(390)	$(118)	$(272)

7. 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 income from continuing operations and weighted average units used in computing basic and diluted income from continuing operations per unit is as follows:

	Three Months Ended March 31,	
	2013	2012
Income from continuing operations	$402	$1,089
Less: Income (loss) from continuing operations attributable to noncontrolling interest	89	(27)
Income from continuing operations, net of noncontrolling interest	313	1,116
General Partner's interest in income from continuing operations	128	117
Limited Partners' interest in income from continuing operations	185	999
Distributions on employee unit awards, net of allocation to General Partner	(3)	(10)
Income from continuing operations available to Limited Partners	182	989
Weighted average Limited Partner units — basic	300,831,573	226,549,263
Basic income from continuing operations per Limited Partner unit	$0.60	$4.37
Dilutive effect of unvested Unit Awards	1,001,337	857,221
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	301,832,910	227,406,484
Diluted income from continuing operations per Limited Partner unit	$0.60	$4.36
Basic income (loss) from discontinued operations per Limited Partner unit	$0.03	$(0.01)
Diluted income (loss) from discontinued operations per Limited Partner unit	$0.03	$(0.01)

8. DEBT OBLIGATIONS:

Senior Notes

In January 2013, ETP issued $800 million of 3.6% Senior Notes due February 2023 and $450 million of 5.15% Senior Notes due February 2043. The net proceeds of $1.24 billion from the offering to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

In January 2013, Sunoco Logistics issued $350 million of 3.45% Senior Notes and $350 million of 4.95% Senior Notes (the "2023 and 2043 Senior Notes"), due January 2023 and January 2043, respectively. The terms and conditions of the 2023 and 2043 Senior Notes are comparable to those under Sunoco Logistics' existing senior notes. The net proceeds of $691 million from the offering were used to pay outstanding borrowings under the Sunoco Logistics' Credit Facilities and for general partnership purposes.

Credit Facilities

ETP Credit Facility

ETP has a $2.5 billion revolving credit facility (the "ETP Credit Facility") that expires in October 2016. Indebtedness under 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.

As of March 31, 2013, the ETP Credit Facility had $250 million outstanding, and the amount available for future borrowings was $2.17 billion after taking into account letters of credit of $76 million. The weighted average interest rate on the total amount outstanding as of March 31, 2013 was 1.70%.

Southern Union Credit Facility

The Southern Union Credit Facility provides for borrowing of up to $700 million and expires in May 2016. Borrowings under the Southern Union Credit Facility are available for working capital, other general company purposes and letter of credit requirements. Outstanding borrowings under the Southern Union Credit Facility were $240 million as of March 31, 2013. The weighted average interest rate on the total amount outstanding as of March 31, 2013 was 1.83%.

In connection with the SUGS Contribution, borrowings under the Southern Union Credit Facility were repaid and the facility was terminated.

Table of Contents

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains two credit facilities to fund its working capital requirements, finance acquisitions and capital projects and for general partnership purposes. The credit facilities consist of a $350 million unsecured credit facility which expires in August 2016 and a $200 million unsecured credit facility which expires in August 2013. There were no outstanding borrowings under these credit facilities as of March 31, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving credit facility. Outstanding borrowings under this credit facility were $33 million as of March 31, 2013.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of March 31, 2013.

9. EQUITY:

Class G Units

In April 2013, all of the outstanding ETP Class F Units, which were issued in connection with the Sunoco Merger, were exchanged for ETP Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units are based on a predetermined percentage and are not contingent on whether ETP has net income or loss.

Common Units Issued

The change in Common Units during the three months ended March 31, 2013 was as follows:

	Number of Units
Outstanding at December 31, 2012	301,485,604
Common Units issued in connection with the Equity Distribution Agreement	3,613,900
Common Units issued in connection with the Distribution Reinvestment Plan	523,082
Common Units issued under equity incentive plans	5,000
Outstanding at March 31, 2013	305,627,586

During the three months ended March 31, 2013, we received proceeds of $169 million, net of commissions of $2 million, from units issued pursuant to an Equity Distribution Agreement with Merrill Lynch, Pierce, Fenner & Smith Incorporated, which were used for general partnership purposes. We also received $29 million, net of commissions, in April 2013 from the settlement of transactions initiated in March 2013. No Common Units remain available to be issued under this agreement.

For the three months ended March 31, 2013, distributions of $23 million were reinvested under the Distribution Reinvestment Plan resulting in the issuance of 0.5 million Common Units. As of March 31, 2013, a total of 3.8 million Common Units remain available to be issued under the existing registration statement.

On April 10, 2013, we issued 13.8 million Common Units representing limited partner interests at $48.05 per Common Unit in a public unit offering. Net proceeds of $657 million from the offering were used to repay amounts outstanding under the ETP Credit Facility and for general partnership purposes.

Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by ETP subsequent to December 31, 2012:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 7, 2013	February 14, 2013	$0.89375
March 31, 2013	May 6, 2013	May 15, 2013	0.89375

Table of Contents

Sunoco Logistics Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2012:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$0.54500
March 31, 2013	May 9, 2013	May 15, 2013	0.57250

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to $220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012. In conjunction with the Holdco transaction in October 2012, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012. As discussed in Note 3, in connection with ETP's acquisition of ETE's 60% interest in Holdco on April 30, 2013, ETE also agreed to relinquish incentive distributions for the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred, and 50% of the incentive distributions for the following eight consecutive quarters on the newly issued Common Units.

Accumulated Other Comprehensive Loss

The following table presents the components of accumulated other comprehensive loss, net of tax:

	March 31, 2013	December 31, 2012
Net gains on commodity related hedges	$1	$—
Available-for-sale securities	1	—
Foreign currency translation adjustment	(1)	—
Actuarial loss related to pensions and other postretirement benefits	(11)	(10)
Equity investments, net	(2)	(9)
Subtotal	$(12)	$(19)
Amounts attributable to noncontrolling interest	7	6
Total accumulated other comprehensive loss, net of tax	$(5)	$(13)

10. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plans

During the three months ended March 31, 2013, employees were granted a total of 1,064,413 unvested awards with five-year service vesting requirements, and directors were granted a total of 9,060 unvested awards with three-year and five-year service vesting requirements. The weighted average grant-date fair value of these awards was $45.33 per unit. As of March 31, 2013 a total of 2,885,465 unit awards remain unvested, for which we expect to recognize a total of $88 million in compensation expense over a weighted average period of 1.9 years related to unvested awards.

Sunoco Logistics' Unit-Based Compensation Plan

As of March 31, 2013, a total of 964,465 Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $23 million of expense over a weighted-average period of 2.6 years.

Table of Contents

11. RETIREMENT BENEFITS:

The following table sets forth the components of net period benefit cost of the Partnership's pension and other postretirement benefit plans for the periods presented below:

	Three Months Ended March 31,			
	2013		2012[1]	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$2	$—	$—	$—
Interest cost	9	2	—	—
Expected return on plan assets	(15)	(3)	—	—
Actuarial loss amortization	1	—	—	—
Settlement credits	(2)	—	—	—
Curtailment recognition[2]	—	—	—	(15)
	(5)	(1)	—	(15)
Regulatory adjustment[3]	2	3	—	—
Net periodic benefit cost	$(3)	$2	$—	$(15)

(1) The three months ended March 31, 2012 includes components of net periodic benefit cost of Southern Union subsequent to the Southern Union Merger on March 26, 2012.

(2) Subsequent to the Southern Union Merger, Southern Union amended certain of its other postretirement employee benefit plans, which prospectively restrict participation in the plans for the impacted active employees. The plan amendments resulted in the plans becoming currently over-funded and, accordingly, Southern Union recorded a pre-tax curtailment gain of $75 million. Such gain was offset by establishment of a non-current refund liability in the amount of $60 million. As such, the net curtailment gain recognition was $15 million.

(3) In its distribution operations, Southern Union recovers certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act of 1974, as amended, or other utility commission specific guidelines. The difference between these regulatory-based amounts and the periodic benefit cost calculated pursuant to GAAP is deferred as a regulatory asset or liability and amortized to expense over periods in which this difference will be recovered in rates, as promulgated by the applicable utility commission.

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

FERC Audit

The FERC is currently conducting an audit of PEPL, a subsidiary of Southern Union for the period from January 1, 2010 through December 31, 2011, to evaluate its compliance with the Uniform System of Accounts as prescribed by the FERC, annual and quarterly financial reporting to the FERC, reservation charge crediting policy and record retention.

Contingent Residual Support Agreement – AmeriGas

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

Table of Contents

PEPL Holdings Guarantee of Collection

In accordance with the Contribution Agreement pursuant to which Southern Union contributed SUGS to Regency, Regency issued $600 million of 4.50% Senior Notes due 2023 (the “Regency Debt”), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, under the Contribution Agreement and pay certain other expenses or disbursements directly related to the closing of the SUGS contribution. In connection with the closing of the SUGS contribution, on April 30, 2013, Regency entered into the guarantee of collection with PEPL Holdings, a subsidiary of Southern Union, pursuant to which PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas. We believe that these pipelines do not provide interstate service and that they are thus not subject to the jurisdiction of the FERC under the Interstate Commerce Act (“ICA”) and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. We cannot guarantee that the jurisdictional status of our NGL facilities will remain unchanged; however, should they be found jurisdictional, the FERC’s rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

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 2056. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled $32 million and $6 million for the three months ended March 31, 2013 and 2012, respectively, which include contingent rentals totaling $4 million in the three months ended March 31, 2013. During the three months ended March 31, 2013, $5 million of rental expense was recovered through related sublease rental income.

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 crude 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.

Sunoco Litigation

Following the announcement of the Sunoco Merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco Merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco’s board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. In September 2012, all of these lawsuits were settled with no payment obligation on the part of any of the defendants following the filing of Current Reports on Form 8-K that included additional disclosures that were incorporated by reference into the proxy statement related to the Sunoco Merger. Subsequent to the settlement of these cases, the plaintiffs' attorneys sought compensation from Sunoco for attorneys' fees related to their efforts in obtaining these additional disclosures. In January 2013, Sunoco entered into agreements to compensate the plaintiffs' attorneys in the state court actions in the aggregate amount of not more than $950,000 and to compensate the plaintiffs' attorneys in the federal court action in the amount of not more than $250,000. The payment of $950,000 is pending approval by the state court. A final approval hearing is set for June 26, 2013.

Litigation Relating to the Southern Union Merger

In June 2011, several putative class action lawsuits were filed in the Judicial District Court of Harris County, Texas naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. The lawsuits were styled Jaroslawicz v. Southern Union Company, et al., Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas and Magda v. Southern Union Company, et al., Cause No. 2011-37134, in the 11th Judicial District Court of Harris County, Texas. The lawsuits were consolidated into an action styled In re: Southern Union Company; Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas. Plaintiffs allege that the Southern Union directors breached their fiduciary duties to Southern Union's stockholders in connection with the Merger and that Southern Union and ETE aided and abetted the alleged breaches of fiduciary duty. The amended petitions allege that the Merger involves an unfair price and an inadequate sales process, that Southern Union's directors entered into the Merger to benefit themselves personally, including through consulting and noncompete agreements, and that defendants have failed to disclose all material information related to the Merger to Southern Union stockholders. The amended petitions seek injunctive relief, including an injunction of the Merger, and an award of attorneys' and other fees and costs, in addition to other relief. On October 21, 2011, the court denied ETE's October 13, 2011, motion to stay the Texas proceeding in favor of cases pending in the Delaware Court of Chancery.

Also in June 2011, several putative class action lawsuits were filed in the Delaware Court of Chancery naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. Three of the lawsuits also named Merger Sub as a defendant. These lawsuits are styled: Southeastern Pennsylvania Transportation Authority, et al. v. Southern Union Company, et al., C.A. No. 6615-CS; KBC Asset Management NV v. Southern Union Company, et al., C.A. No. 6622-CS; LBBW Asset Management Investment GmbH v. Southern Union Company, et al., C.A. No. 6627-CS; and Memo v. Southern Union Company, et al., C.A. No. 6639-CS. These cases were consolidated with the following style: In re Southern Union Co. Shareholder Litigation, C.A. No. 6615-CS, in the Delaware Court of Chancery. The consolidated complaint asserts similar claims and allegations as the Texas state-court consolidated action. On July 25, 2012, the Delaware plaintiffs filed a notice of voluntary dismissal of all claims without prejudice. In the notice, plaintiffs stated their claims were being dismissed to avoid duplicative litigation and indicated their intent to join the Texas case.

The Texas case remains pending, and discovery is ongoing.

MTBE Litigation

Sunoco, along with other refiners, manufacturers and sellers of gasoline, is a defendant in lawsuits alleging MTBE contamination of groundwater. The plaintiffs typically include water purveyors and municipalities responsible for supplying drinking water and governmental authorities. The plaintiffs are asserting primarily product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. The plaintiffs in all of the cases are seeking to recover compensatory damages, and in some cases, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2012, Sunoco was a defendant in two lawsuits involving one state and Puerto Rico. These cases are venued in a multidistrict proceeding in a New York federal court. Both cases assert natural resource damage claims. In addition, Sunoco has received notice from another state that it intends to file an MTBE lawsuit in the near future asserting natural resource damage claims.

Discovery is proceeding in these cases. There has been insufficient information developed about the plaintiffs' legal theories or the facts in the natural resource damage claims that would be relevant to an analysis of the ultimate liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on its consolidated financial position.

Other Litigation and Contingencies

In November 2011, a derivative lawsuit was filed in the Judicial District Court of Harris County, Texas naming as defendants ETP, ETP GP, ETP LLC, the boards of directors of ETP LLC (collectively with ETP GP and ETP LLC, the “ETP Defendants”), certain members of management for ETP and ETE, ETE, and Southern Union. The lawsuit is styled W. J. Garrett Trust v.

Table of Contents

Bill W. Byrne, et al., Cause No. 2011-71702, in the 157th Judicial District Court of Harris County, Texas. Plaintiffs assert claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and the individual defendants. Plaintiffs also assert claims for aiding and abetting and tortious interference with contract against Southern Union. On October 5, 2012, certain defendants filed a motion for summary judgment with respect to the primary allegations in this action. On December 13, 2012, Plaintiffs filed their opposition to the motion for summary judgment. Defendants filed a reply on December 19, 2012. On December 20, 2012, the court conducted an oral hearing on the motion. Plaintiffs filed a post-hearing sur-reply on January 7, 2013. On January 16, 2013, the Court granted defendants' motion for summary judgment. The deadline for the remaining defendants to file an answer or otherwise respond was late April 2013. Trial in this action is not currently set.

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of March 31, 2013 and December 31, 2012, accruals of approximately $42 million were reflected on our balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

No amounts have been recorded in our March 31, 2013 or December 31, 2012 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Will Price. Will Price, an individual, filed actions in the U.S. District Court for the District of Kansas for damages against a number of companies, including Panhandle, alleging mis-measurement of natural gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On September 19, 2009, the Court denied plaintiffs' request for class certification. Plaintiffs have filed a motion for reconsideration, which the Court denied on March 31, 2010. Panhandle believes that its measurement practices conformed to the terms of its FERC natural gas tariffs, which were filed with and approved by the FERC. As a result, Southern Union believes that it has meritorious defenses to the Will Price lawsuit (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Panhandle complied with the terms of its tariffs). In the event that Plaintiffs refuse Panhandle's pending request for voluntary dismissal, Panhandle will continue to vigorously defend the case. Southern Union believes it has no liability associated with this proceeding.

Simmons v. Southern Union Company. Cause No. 1316-CV-07265, in the Circuit Court of Jackson County, Missouri, Kansas City: On March 22, 2013, the first lawsuit related to the February 19, 2013 natural gas incident at JJ's Restaurant was filed in Missouri state court on behalf of six injured restaurant employees. The defendants include Southern Union Company d/b/a MGE, USIC Locating Services, Inc. (the utility marking service), Heartland Midwest, LLC (the directional boring company and contractor of Time Warner Cable Media, Inc.), Time Warner Cable Media, Inc., Missouri One Call System, Inc., (Missouri's notification center for utility locates), and Mike Palier (MGE's first responder). Plaintiffs' claims include negligence and strict liability for inherently dangerous activities. Plaintiffs have not specified an amount of damages, but seek punitive damages against MGE and certain other defendants in a jury trial. No trial date has been set.

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General ("AG") filed a regulatory complaint with the MDPU against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged "excessive and imprudently incurred costs" related to legal fees associated with Southern Union's environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company's collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, the Southern Union former Vice Chairman, President and Chief Operating Officer, joined Southern Union's management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism since 2005, the period during which a member of the firm served as Southern Union's Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the AG contends only qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral

Table of Contents

estoppel. The hearing officer has deferred consideration of Southern Union's motion to dismiss. The AG's motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. The hearing officer has stayed discovery until resolution of a separate matter concerning the applicability of attorney-client privilege to legal billing invoices. Southern Union believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Southern Union will continue to assess its potential exposure for such cost recoveries as the matter progresses.

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, there can be no assurance 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, will not result in substantial costs and liabilities. 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.

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.

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Southern Union's distribution operations are responsible for soil and groundwater remediation at certain sites related to manufactured gas plants ("MGPs") and may also be responsible for the removal of old MGP structures.
- Currently operating Sunoco retail sites.
- Legacy sites related to Sunoco, that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party ("PRP"). As of March 31, 2013, Sunoco had been named as a PRP at 39 identified or potentially identifiable as "Superfund" sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco's purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated balance sheets.

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	March 31, 2013	December 31, 2012
Current	$41	$46
Non-current	164	165
Total environmental liabilities	$205	$211

During the three months ended March 31, 2013, Sunoco recorded $7 million of expenditures related to environmental cleanup programs.

The EPA's 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 Clean Air Act ("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 we replace equipment or expand existing facilities 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.

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. 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.

Table of Contents

13. 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 withdraw 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 and storage 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.

We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream segment whereby the our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGLs. We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes. Certain contracts that qualify for hedge accounting are accounted for as cash flow hedges. 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.

Table of Contents

The following table details our outstanding commodity-related derivatives:

	March 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX [1]	3,057,500	2013-2014	(30,980,000)	2013-2014
Power (Megawatt):				
Forwards	311,150	2013	19,650	2013
Futures	(452,400)	2013	(1,509,300)	2013
Options — Calls	57,600	2013	1,656,400	2013
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(1,867,500)	2013-2014	150,000	2013
Swing Swaps IFERC	(11,755,000)	2013	(83,292,500)	2013
Fixed Swaps/Futures	(6,065,000)	2013-2015	27,077,500	2013
Forward Physical Contracts	2,021,900	2013-2014	11,689,855	2013-2014
Natural Gas Liquid (Bbls):				
Forwards/Swaps	(205,000)	2013	(30,000)	2013
Refined Products (Bbls) — Futures	1,772	2013-2014	(666,000)	2013
Crude (Bbls) — Futures	(120,000)	2013	—	—
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(6,960,000)	2013	(18,655,000)	2013
Fixed Swaps/Futures	(7,260,000)	2013	(44,272,500)	2013
Hedged Item — Inventory	7,260,000	2013	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(3,437,500)	2013	—	—
Fixed Swaps/Futures	(9,625,000)	2013	(8,212,500)	2013
Natural Gas Liquid (Bbls):				
Forwards/Swaps	(695,000)	2013	(930,000)	2013
Refined Products (Bbls) — Futures	—	—	(98,000)	2013
Crude (Bbls) — Futures	(270,000)	2013	—	—

(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 losses of $5 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps

Table of Contents

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.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type(1)	March 31, 2013	December 31, 2012
ETP	July 2013(2)	Forward-starting to pay a fixed rate of 4.02% and receive a floating rate	$400	$400
ETP	July 2014(2)	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	January 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	200	—
Southern Union	November 2016	Pay a fixed rate of 2.91% and receive a floating rate	75	75
Southern Union	November 2021	Pay a fixed rate of 3.75% and receive a floating rate	450	450

(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, 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.

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 $23 million and $41 million as of March 31, 2013 and December 31, 2012, respectively.

Certain of Southern Union's derivative instruments contain provisions that require Southern Union's debt to be maintained at an investment grade credit rating from each of the major credit rating agencies. If Southern Union's debt were to fall below investment grade, Southern Union would be in violation of these provisions, and the counterparties to the derivative instruments could potentially require Southern Union to post collateral for certain of the derivative instruments.

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 a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	March 31, 2013	December 31, 2012	March 31, 2013	December 31, 2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$4	$8	$(14)	$(10)
	$4	$8	$(14)	$(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	$120	$110	$(125)	$(116)
Commodity derivatives	59	33	(53)	(34)
Current assets held for sale	8	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	(2)	(9)
Interest rate derivatives	51	55	(213)	(223)
	238	200	(393)	(382)
Total derivatives	$242	$208	$(407)	$(392)

In addition to the above derivatives, $1 million and $6 million in option premiums were included in “Price risk management assets” and “Price risk management liabilities,” respectively, as of March 31, 2013 are being amortized in 2013. In addition to the above derivatives, $7 million in option premiums were included in “Price risk management liabilities” as of December 31, 2012.

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
Contract Type	Balance Sheet Location	March 31, 2013	December 31, 2012	March 31, 2013	December 31, 2012
Bi-lateral contracts	Price risk management asset (liability)	$54	$28	$(52)	$(27)
Broker cleared derivative contracts	Other current assets (liabilities)	183	149	(225)	(221)
	Gross fair value	237	177	(277)	(248)
Collateral paid to OTC counterparties	Other current assets (liabilities)	—	—	—	2
Counterparty netting	Price risk management asset (liability)	(51)	(25)	51	25
Payments on margin deposit	Other current assets (liabilities)	—	—	38	59
	Net fair value	$186	$152	$(188)	$(162)

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.

Table of Contents

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

	Change in Value Recognized in OCI on Derivatives (Effective Portion)	
	Three Months Ended March 31,	
	2013	2012
Derivatives in cash flow hedging relationships:		
Commodity derivatives	$ 2	$ 20
Total	$ 2	$ 20

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
		Three Months Ended March 31,	
		2013	2012
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$1	$3
Total		$1	$3

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness	
		Three Months Ended March 31,	
		2013	2012
Derivatives in fair value hedging relationships (including hedged item):			
Commodity derivatives	Cost of products sold	$5	$(9)
Total		$5	$(9)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2013	2012
Derivatives not designated as hedging instruments:			
Commodity derivatives – Trading	Cost of products sold	$(4)	$(11)
Commodity derivatives – Non-trading	Cost of products sold	(18)	(3)
Commodity derivatives – Non-trading	Deferred gas purchases	(5)	—
Interest rate derivatives	Gains on interest rate derivatives	7	28
Total		$(20)	$14

Table of Contents

14. RELATED PARTY TRANSACTIONS:

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

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

Sunoco Logistics has an agreement with PES relating to the Fort Mifflin Terminal Complex. Under this agreement, PES will deliver an average of 300,000 Bbls/d of crude oil and refined products per contract year at the Fort Mifflin facility. PES does not have exclusive use of the Fort Mifflin Terminal Complex; however, Sunoco Logistics is obligated to provide the necessary tanks, marine docks and pipelines for PES to meet its minimum requirements under the agreement. Sunoco Logistics executed a 10-year agreement with PES in September 2012.

In September 2012, Sunoco assigned its lease for the use of Sunoco Logistics' inter-refinery pipelines between the Philadelphia and Marcus Hook refineries to PES. Under the 20-year lease agreement which expires in February 2022, PES leases the inter-refinery pipelines for an annual fee which escalates at 1.67% each January 1 for the term of the agreement. The lease agreement also requires PES to reimburse Sunoco Logistics for any non-routine maintenance expenditures, as defined, incurred during the term of the agreement. There were no material reimbursements under this agreement during 2010 through 2012.

The following table summarizes the affiliate revenue on our consolidated statements of operations:

	Three Months Ended March 31,	
	2013	2012
Affiliated revenue	$382	$7

The following table summarizes the related company balances on our consolidated balance sheets:

	March 31, 2013	December 31, 2012
Accounts receivable from related companies:		
ETE	$13	$16
Regency	11	10
PES	57	60
FGT	34	2
Other	27	6
Total accounts receivable from related companies:	$142	$94
Accounts payable to related companies:		
ETE	$8	$7
Regency	3	2
PES	1	13
FGT	7	—
Other	8	2
Total accounts payable to related companies:	$27	$24

Table of Contents

15. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	March 31, 2013	December 31, 2012
Deposits paid to vendors	$23	$41
Prepaid expenses and other	301	293
Total other current assets	$324	$334

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	March 31, 2013	December 31, 2012
Interest payable	$245	$256
Customer advances and deposits	36	44
Accrued capital expenditures	355	356
Accrued wages and benefits	126	236
Taxes payable other than income taxes	231	203
Income taxes payable	39	40
Deferred income taxes	86	130
Other	215	297
Total accrued and other current liabilities	$1,333	$1,562

16. REPORTABLE SEGMENTS:

As a result of the Sunoco Merger and Holdco Transaction, our reportable segments were re-evaluated and changed in 2012. Our financial statements currently reflect six 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 and storage;
- midstream;
- NGL transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and
- all other.

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 and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our investment in Sunoco

Table of Contents

Logistics segment are primarily reflected in crude sales. Revenues from our Retail marketing segment are primarily reflected in refined product sales.

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership's proportionate ownership. Previously, amounts for less than wholly owned subsidiaries were reflected in Segment Adjusted EBITDA based on the Partnership's proportionate ownership, such that the measure was reduced for amounts attributable to noncontrolling interests. During the three months ended December 31, 2012, management changed its definition of Segment Adjusted EBITDA to reflect amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations. Management believes that the revised segment performance measure more closely reflects the presentation of less than wholly owned subsidiaries within the Partnership's consolidated financial statements. For periods prior to the three months ended December 31, 2012, only the NGL transportation and services segment included a less than wholly owned subsidiary. Based on this change in our definition of Segment Adjusted EBITDA, we have recast the presentation of our segment results for 2012 to be consistent with the current year presentation.

Table of Contents

The following tables present the financial information by segment:

	Three Months Ended March 31,	
	2013	2012
Revenues:		
Intrastate transportation and storage:		
Revenues from external customers	$651	$447
Intersegment revenues	39	35
	690	482
Interstate transportation and storage:		
Revenues from external customers	323	142
Intersegment revenues	1	—
	324	142
Midstream:		
Revenues from external customers	750	459
Intersegment revenues	201	104
	951	563
NGL transportation and services:		
Revenues from external customers	346	154
Intersegment revenues	19	13
	365	167
Investment in Sunoco Logistics:		
Revenues from external customers	3,457	—
Intersegment revenues	55	—
	3,512	—
Retail marketing:		
Revenues from external customers	5,217	—
Intersegment revenues	5	—
	5,222	—
All other:		
Revenues from external customers	110	121
Intersegment revenues	40	8
	150	129
Eliminations	(360)	(160)
Total revenues	$10,854	$1,323

31

Table of Contents

	Three Months Ended March 31, 2013	2012
Segment Adjusted EBITDA:		
Intrastate transportation and storage	$132	$192
Interstate transportation and storage	297	80
Midstream	79	89
NGL transportation and services	80	50
Investment in Sunoco Logistics	236	—
Retail marketing	37	—
All other	95	83
Total	956	494
Depreciation and amortization	(260)	(99)
Interest expense, net of interest capitalized	(211)	(141)
Gain on deconsolidation of Propane Business	—	1,056
Gains on interest rate derivatives	7	28
Non-cash unit-based compensation expense	(14)	(11)
Unrealized gains (losses) on commodity risk management activities	19	(86)
LIFO valuation adjustment	38	—
Loss on extinguishment of debt	—	(115)
Adjusted EBITDA attributable to discontinued operations	(40)	(7)
Adjusted EBITDA related to unconsolidated affiliates	(165)	(99)
Equity in earnings of unconsolidated affiliates	72	55
Other, net	3	16
Income from continuing operations before income tax expense	$405	$1,091

	March 31, 2013	December 31, 2012
Total assets:		
Intrastate transportation and storage	$4,579	$4,691
Interstate transportation and storage	11,749	11,794
Midstream	4,989	5,098
NGL transportation and services	3,904	3,765
Investment in Sunoco Logistics	10,993	10,291
Retail marketing	4,039	3,926
All other	4,115	3,665
Total	$44,368	$43,230

Table of Contents

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

(Tabular dollar amounts are in millions)

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, 2012 filed with the SEC on March 1, 2013. 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 I - Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2012.

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

Overview

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

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage through Southern Union and La Grange Acquisition, L.P., which conducts business under the assumed name of ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Southern Union. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry. Southern Union is the parent company of Panhandle, which provides transportation and storage services through the Panhandle, Trunkline and Sea Robin transmission systems.
- NGL transportation, storage and fractionation services primarily through Lone Star.
- Refined product and crude oil operations, including the following:
  - refined product and crude oil transportation through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco.
- Other operations, including the following:
  - natural gas compression services through ETC Compression;
  - a limited partner interest in AmeriGas;
  - natural gas distribution operations through Southern Union; and
  - an approximate 30% non-operating interest in a refining joint venture.

Recent Developments

Sale of Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with The Laclede Group, Inc., pursuant to which Laclede Missouri has agreed to acquire the assets of Southern Union's Missouri Gas Energy division, and Laclede Massachusetts has agreed to acquire the assets of Southern Union's New England Gas Company division. Total consideration is expected to be $1.04 billion, subject to customary closing adjustments, less the assumption of $19 million of debt. On February 11, 2013, The Laclede Group, Inc. announced that it had entered into an agreement with APUC that will allow a subsidiary of APUC to assume the right of The Laclede Group, Inc. to purchase the assets of Southern Union's New England Gas Company division, subject to certain approvals. It is expected that the transactions contemplated by the purchase and sale agreement will close in the third quarter of 2013.

For the three months ended March 31, 2013 and the period from March 26, 2012 to March 31, 2012, the distribution operations have been classified as discontinued operations in the consolidated statements of operations. The assets and liabilities of the disposal group have been classified as assets and liabilities held for sale as of March 31, 2013 and December 31, 2012.

Crude Oil Joint Venture with Enbridge

On February 15, 2013, Enbridge Inc. ("Enbridge") and ETP announced that we have entered into an agreement on the terms for the joint development of a project to provide crude oil pipeline access to the eastern Gulf Coast refinery market from the Patoka, Illinois hub. The project will involve the conversion from natural gas service to crude oil service of certain segments of pipeline that are currently in operation as part of the natural gas system of Trunkline, a subsidiary of ETP. This agreement is subject to

approval by the FERC of Trunkline's July 2012 request to abandon certain designated segments of pipeline from natural gas transmission service. The converted 30-inch diameter crude oil pipeline is expected to be in service by 2015. It will have capacity of up to 420,000 to 660,000 Bbls/d depending on crude slate and the level of subscriptions received in an open season to be conducted in the near future. Once completed, the project will span more than 700 miles, including a new lateral from central Louisiana, near the town of Boyce, to the refining market and the crude oil hub at St. James, Louisiana. The St. James hub will provide access to refineries in the eastern Gulf Coast, as well as dock access for water-borne shipments.

Enbridge and ETP would each own 50% of the joint venture entity. Enbridge's participation in the venture is subject to a minimum level of commitments being obtained in the open season and on completion of due diligence.

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The total cash consideration was reduced by $107 million of estimated closing adjustments. In addition, PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the Contribution Agreement. The Regency Class F units have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis. Upon the closing of the transaction, ETE agreed to forego all distributions with respect to its IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing.

Acquisition of ETE's Holdco Interest

On April 30, 2013, ETP acquired from ETE its interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of estimated closing adjustments. ETE, which owns the general partner and IDRs of ETP, has agreed to forego all of the IDR payments on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurs, and 50% of the IDR payments on the newly issued ETP units for the following eight consecutive quarters. As a result, ETP now owns 100% of Holdco. As this transaction occurred subsequent to March 31, 2013, the consolidated historical results of operations, cash flows and financial position as of and for the quarter ended March 31, 2013 were not affected by this transaction.

Equity Offering

On April 10, 2013, we issued 13.8 million Common Units representing limited partner interests at $48.05 per Common Unit in a public offering. Net proceeds of $657 million from the offering were used to repay amounts outstanding under the ETP Credit Facility 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 pursuing organic growth projects related to our existing assets and integrating strategic acquisitions completed in recent years including the acquisition with Regency of LDH, the Citrus Acquisition, the Sunoco merger, and the Holdco Transaction. 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.

During the past several years, we have been successful in completing several transactions that have increased our distributable cash flow. We have also made, and are continuing to make, significant investments in organic growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will contribute to growth in our distributable cash flow for years to come.

Our principal operations as of March 31, 2013 included the following segments:

- Intrastate transportation and storage — Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that primarily impact our interruptible business are primarily among receipt points between West Texas to East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold. Conversely, when basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary

Table of Contents

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 transportation and storage — The majority of our interstate transportation and storage revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Certain shippers have made long-term 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. 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.

Table of Contents

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. The Mont Belvieu NGL fractionation facility fractionates mixed NGLs from major NGL supply basins and is supported by long-term customer commitments.

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.

- Investment in Sunoco Logistics — Revenues are generated by charging tariffs for transporting refined products, crude oil and other hydrocarbons through our pipelines as well as by charging fees for terminalling services for refined products, crude oil and other hydrocarbons at our facilities. Revenues are also generated by acquiring and marketing crude oil and refined products. Generally, crude oil and refined products purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.

- Retail marketing — Revenue is principally generated from the sale of gasoline and middle distillates and the operation of convenience stores primarily on the east coast and in the midwest region of the United States. These stores supplement sales of fuel products with a broad mix of merchandise such as groceries, fast foods, beverages and tobacco products.

Table of Contents

Results of Operations

Consolidated Results

	Three Months Ended March 31, 2013	2012	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$132	$192	$(60)
Interstate transportation and storage	297	80	217
Midstream	79	89	(10)
NGL transportation and services	80	50	30
Investment in Sunoco Logistics	236	—	236
Retail marketing	37	—	37
All other	95	83	12
Total	956	494	462
Depreciation and amortization	(260)	(99)	(161)
Interest expense, net of interest capitalized	(211)	(141)	(70)
Gain on deconsolidation of Propane Business	—	1,056	(1,056)
Gains on interest rate derivatives	7	28	(21)
Non-cash unit-based compensation expense	(14)	(11)	(3)
Unrealized gains (losses) on commodity risk management activities	19	(86)	105
LIFO valuation adjustment	38	—	38
Loss on extinguishment of debt	—	(115)	115
Adjusted EBITDA attributable to discontinued operations	(40)	(7)	(33)
Adjusted EBITDA related to unconsolidated affiliates	(165)	(99)	(66)
Equity in earnings of unconsolidated affiliates	72	55	17
Other, net	3	16	(13)
Income from continuing operations before income tax expense	405	1,091	(686)
Income tax expense	(3)	(2)	(1)
Income from continuing operations	402	1,089	(687)
Income (loss) from discontinued operations	22	(1)	23
Net income	$424	$1,088	$(664)

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization increased for the three months ended March 31, 2013 compared to the same period last year primarily due to:

- depreciation and amortization related to Southern Union of $59 million;
- depreciation and amortization related to Sunoco Logistics and Sunoco of $92 million; and
- additional depreciation and amortization recorded from assets placed in service.

Interest Expense. Interest expense increased for the three months ended March 31, 2013 compared to the same period last year primarily due to:

- interest expense recorded by Southern Union of $33 million;
- interest expense recorded by Sunoco Logistics and Sunoco of $28 million; and
- incremental interest expense due to the issuance of $1.25 billion of Senior Notes in January 2013; offset by

Table of Contents

- a reduction of several series of our higher coupon notes that were repurchased in the tender offers 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 on Interest Rate Derivatives. Gains on interest rate derivatives were higher in the prior period due to an increase in forward rates during the three months ended March 31, 2012, which resulted in unrealized gains on our forward-starting floating-to-fixed swaps.

Unrealized (Gains) Losses on Commodity Risk Management Activities. See discussion of the unrealized (gains) losses on commodity risk management activities included in “Segment Operating Results” below.

LIFO Valuation Adjustment. A LIFO valuation reserve adjustment was recorded for the inventory associated with Sunoco’s retail marketing operations as a result of commodity price changes between periods.

Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized for the three months ended March 31, 2012 in connection with our repurchase of $750 million of Senior Notes in January 2012.

Adjusted EBITDA Attributable to Discontinued Operations. Amounts reflect the operations of Canyon, which was sold in October 2012, and Southern Union’s distribution operations beginning March 26, 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. See additional information in “Supplemental Information on Unconsolidated Affiliates” and “Segment Operating Results” below. Our investments in AmeriGas and Citrus are only reflected for a partial period during the three months ended March 31, 2012.

Other, net. Includes amortization of regulatory assets and other income and expense amounts.

Income Tax Expense. Income tax expense increased primarily due to the acquisitions of Southern Union and Sunoco, both of which are taxable corporations.

Supplemental Pro Forma Financial Information

The following unaudited pro forma consolidated financial information of ETP has been prepared in accordance with Article 11 of Regulation S-X and reflects the pro forma impacts of the Sunoco Merger and Holdco Transaction for the three months ended March 31, 2012 giving effect that each occurred on January 1, 2012. This unaudited pro forma financial information is provided to supplement the discussion and analysis of the historical financial information and should be read in conjunction with such historical financial information. This unaudited pro forma information is for illustrative purposes only and is not necessarily indicative of the financial results that would have occurred if the Sunoco Merger and Holdco Transaction had been consummated on January 1, 2012.

Table of Contents

The following table presents pro forma financial information for the three months ended March 31, 2012.

	ETP Historical	Propane Transaction (a)	Sunoco Historical (b)	Southern Union Historical (c)	Holdco Pro Forma Adjustments (d)	Pro Forma
REVENUES	$1,323	$(68)	$12,211	$443	$(4,620)	$9,289
COSTS AND EXPENSES:						
Cost of products sold and natural gas operations	911	(55)	11,491	313	(4,264)	8,396
Depreciation and amortization	99	(2)	61	49	26	233
Selling, general and administrative	104	(1)	144	—	(25)	222
Impairment charges	—	—	109	—	(35)	74
Total costs and expenses	1,114	(58)	11,805	362	(4,298)	8,925
OPERATING INCOME	209	(10)	406	81	(322)	364
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(141)	2	(47)	(50)	(20)	(256)
Equity in earnings of affiliates	55	4	3	16	(21)	57
Gain on deconsolidation of Propane Business	1,056	(1,056)	—	—	—	—
Gain (loss) on disposal of assets	(1)	2	104	—	—	105
Loss on extinguishment of debt	(115)	115	—	—	—	—
Gains on interest rate derivatives	28	—	—	—	—	28
Other, net	—	—	3	(2)	—	1
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	1,091	(943)	469	45	(363)	299
Income tax expense	2	—	170	12	(154)	30
INCOME FROM CONTINUING OPERATIONS	$1,089	$(943)	$299	$33	$(209)	$269

(a) Propane Transaction adjustments reflect the following:

- The adjustments reflect the deconsolidation of ETP's propane operations in connection with the Propane Transaction.
- The adjustments reflect the pro forma impacts from the consideration received in connection with the Propane Transaction, including ETP's receipt of AmeriGas common units and ETP's use of cash proceeds from the transaction to redeem long-term debt.
- The 2012 adjustments include the elimination of (i) the gain recognized by ETP in connection with the deconsolidation of the Propane Business and (ii) ETP's loss on extinguishment of debt recognized in connection with the use of proceeds to redeem long-term debt.

(b) Sunoco historical amounts in 2012 include the period from January 1, 2012 through March 31, 2012.

(c) Southern Union historical amounts in 2012 include the period from January 1, 2012 through March 25, 2012.

(d) Substantially all of the Holdco pro forma adjustments relate to Sunoco's exit from its Northeast refining operations and formation of the PES joint venture, except for the following:

- The adjustment to depreciation and amortization reflects incremental amounts for estimated fair values recorded in purchase accounting related to Sunoco and Southern Union.
- The adjustment to selling, general and administrative expenses includes the elimination of merger-related costs incurred, because such costs would not have a continuing impact on results of operations.
-

The adjustment to interest expense includes incremental amortization of fair value adjustments to debt recorded in purchase accounting.

Table of Contents

- The adjustment to equity in earnings of affiliates reflects the reversal of amounts related to Citrus Corp. recorded in Southern Union's historical income statements.
- The adjustment to income tax expense includes the pro forma impact resulting from the pro forma adjustments to pre-tax income of Sunoco and Southern Union.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended March 31,		
	2013	2012	Change
Equity in earnings of unconsolidated affiliates:			
AmeriGas	$63	$40	$23
Citrus	14	1	13
FEP	13	13	—
Other	(18)	1	(19)
Total equity in earnings of unconsolidated affiliates	$72	$55	$17
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:			
AmeriGas	$34	$35	$(1)
Citrus	48	3	45
FEP	5	6	(1)
Other	6	—	6
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$93	$44	$49
Adjusted EBITDA related to unconsolidated affiliates:			
AmeriGas	$97	$75	$22
Citrus	62	4	58
FEP	18	19	(1)
Other	(12)	1	(13)
Total Adjusted EBITDA attributable to unconsolidated affiliates	$165	$99	$66
Distributions received from unconsolidated affiliates:			
AmeriGas	$24	$23	$1
Citrus	24	—	24
FEP	17	18	(1)
Other	30	1	29
Total distributions received from unconsolidated affiliates	$95	$42	$53

Segment Operating Results

Our reportable segments are discussed below. "All other" includes our compression, our equity method investment in AmeriGas, Southern Union's distribution operations, our approximate 30% non-operating interest in PES and our wholesale propane businesses.

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, our all other segment includes eleven days of consolidated activity related to our Propane Business for the three months ended March 31, 2012. Amounts attributable to our investment in AmeriGas are reflected above in "Supplemental Information on Unconsolidated Affiliates."

Table of Contents

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.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for year ended December 31, 2012 filed with the SEC on March 1, 2013.

Intrastate Transportation and Storage

	Three Months Ended March 31,		
	2013	2012	Change
Natural gas transported (MMBtu/d)	9,733,480	10,114,354	(380,874)
Revenues	$690	$482	$208
Cost of products sold	496	314	182
Gross margin	194	168	26
Unrealized (gains) losses on commodity risk management activities	(12)	82	(94)
Operating expenses, excluding non-cash compensation expense	(39)	(39)	—
Selling, general and administrative expenses, excluding non-cash compensation expense	(11)	(19)	8
Segment Adjusted EBITDA	$132	$192	$(60)

Volumes. Transported volumes decreased due to the cessation of certain long-term contracts and lower volumes transported through our pipeline systems as a result of a continued unfavorable natural gas price environment.

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

	Three Months Ended March 31,		
	2013	2012	Change
Transportation fees	$129	$144	$(15)
Natural gas sales and other	27	14	13
Retained fuel revenues	23	17	6
Storage margin, including fees	15	(7)	22
Total gross margin	$194	$168	$26

Intrastate transportation and storage gross margin increased between the periods due to the net impact of the following:

- Transportation fees. Transportation fees decreased primarily due to lower volumes resulting from the cessation of certain long-term transportation contracts and lower volumes transported through our pipeline systems as a result of a continued unfavorable natural gas price environment.

Table of Contents

From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible transportation capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $7 million during the three months ended March 31, 2013 and 2012.

- Natural gas sales and other. Margin from natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. For the three months ended March 31, 2013 compared to the same period last year, margin from natural gas sales and other increased primarily due to an increase of $10 million in margin from system optimization activities and an increase of $2 million in margin from wellhead sales and purchases from the Eagle Ford Shale that were sold to end users on our HPL system. Excluding derivatives related to storage, unrealized gains of $1 million were recorded in the three months ended March 31, 2013 as compared to unrealized losses of $6 million in the same period last year.
- Retained fuel revenues. 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. For the three months ended March 31, 2013 compared to the same period last year, retention fuel revenue increased $6 million primarily due to an increase in the average of natural gas spot prices. The average spot price at the Houston Ship Channel for the three months ended March 31, 2013 increased to $3.43/MMBtu from $2.41/MMBtu in the same period last year. The increase in retained fuel revenues between the periods was attributable to an increase of $8 million due to price increases offset by a decrease of $2 million due to lower retention gas volumes.

Storage margin was comprised of the following:

	Three Months Ended March 31, 2013	2012	Change
Withdrawals from storage natural gas inventory (MMBtu)	37,320,557	546,734	36,773,823
Realized margin on natural gas inventory transactions	$(3)	$61	$(64)
Fair value inventory adjustments	20	(50)	70
Unrealized losses on derivatives	(9)	(26)	17
Margin recognized on natural gas inventory, including related derivatives	8	(15)	23
Revenues from fee-based storage	7	8	(1)
Total storage margin	$15	$(7)	$22

The increase in storage margin for the three months ended March 31, 2013 compared to the same period last year was principally driven by gains on the fair value adjustment of natural gas inventory held at our Bammel storage facility which was partially offset by an unfavorable variance from the settlement of derivatives used to hedge storage gas inventory. In the three months ended March 31, 2012, gains from the settlement of storage derivatives were realized with little physical offset due to the lack of withdrawals during the unusually warm winter season. Storage gas withdrawals resumed during the three months ended March 31, 2013, providing for greater parity between the margin realized on physical sales of storage gas and the loss on settlement of related storage derivatives.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Unrealized gains and 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 to inventory. For the three months ended March 31, 2013, unrealized gains of $12 million included fair value adjustments to storage gas inventory of $20 million, partially offset by unrealized losses on derivatives of $8 million. For the three months ended March 31, 2012, unrealized losses of $82 million included unrealized losses on fair value adjustments to storage gas inventory of $50 million and unrealized losses on derivatives of $32 million. The unrealized losses for the three months ended March 31, 2012 reflected the impact of holding a larger volume of natural gas in our Bammel storage facility due to the warmer weather patterns noted above and were partially offset by settled financial derivative gains of $61 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses reflected a $2 million decrease in pipeline maintenance offset by a $2 million increase in fuel consumption.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses decreased primarily due to employee-related costs and allocated overhead expenses.

Table of Contents

Interstate Transportation and Storage

	Three Months Ended March 31,		
	2013	2012	Change
Natural gas transported (MMBtu/d):			
ETP legacy assets	2,613,154	3,153,073	(539,919)
Southern Union transportation and storage	4,420,650	3,764,599	656,051
Natural gas sold (MMBtu/d) – ETP legacy assets	16,768	20,517	(3,749)
Revenues	$324	$142	$182
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(72)	(32)	(40)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(35)	(53)	18
Adjusted EBITDA related to unconsolidated affiliates	80	23	57
Segment Adjusted EBITDA	$297	$80	$217

Volumes. For the three months ended March 31, 2013 compared to the same period last year, the ETP legacy assets transported volumes decreased on the Tiger pipeline due to declines in supply, and transported volumes decreased on the Transwestern pipeline primarily due to lower basis differentials primarily on the eastern side of the pipeline. For the Southern Union assets, transported volumes increased on a daily average basis primarily due to colder weather along the Panhandle Eastern pipeline.

Revenues. Interstate transportation and storage revenues increased primarily due to the consolidation of Southern Union’s transportation and storage operations beginning March 26, 2012. The increase was offset slightly by a decrease in revenues of $3 million related to the Transwestern and Tiger pipelines.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Substantially all of the increase in interstate transportation and storage operating expenses was due the consolidation of Southern Union’s transportation and storage operations beginning March 26, 2012. The increase was offset slightly by a decrease in operating expenses of $4 million related to the Transwestern and Tiger pipelines.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. The variances in selling, general and administrative expenses were primarily due to the consolidation of Southern Union’s transportation and storage operations, beginning March 26, 2012, which resulted in incremental expenses of $27 million in the three months ended March 31, 2013. The impact of the incremental expenses in the current year was more than offset by Southern Union’s recognition of merger-related expenses during the period from March 26, 2012 to March 31, 2012. Selling, general and administrative expenses related to the Transwestern and Tiger pipelines decreased less than $1 million from the prior year.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates increased for the three months ended March 31, 2013 compared to the same period last year primarily due to an increase of $58 million from Citrus, offset by a decrease of $1 million from FEP. We acquired a 50% interest in Citrus on March 26, 2012.

Table of Contents

Midstream

	Three Months Ended March 31,		
	2013	2012	Change
Gathered volumes (MMBtu/d):			
ETP legacy assets	2,587,787	2,239,220	348,567
Southern Union gathering and processing	480,339	404,422	75,917
NGLs produced (Bbls/d)			
ETP legacy assets	96,775	65,627	31,148
Southern Union gathering and processing	39,681	38,723	958
Equity NGLs produced (Bbls/d)			
ETP legacy assets	9,499	17,630	(8,131)
Southern Union gathering and processing	7,206	8,744	(1,538)
Revenues	$951	$563	$388
Cost of products sold	794	436	358
Gross margin	157	127	30
Unrealized losses on commodity risk management activities	—	2	(2)
Operating expenses, excluding non-cash compensation expense	(49)	(26)	(23)
Selling, general and administrative expenses, excluding non-cash compensation expense	(29)	(19)	(10)
Adjusted EBITDA attributable to discontinued operations	—	5	(5)
Segment Adjusted EBITDA	$79	$89	$(10)

Volumes. NGL production increased primarily due to increased inlet volumes as a result of more production by our customers in the Eagle Ford Shale area. The decrease in equity NGL production was primarily due to processing plants optimizing NGL recoveries in response to the current NGL pricing environment.

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

	Three Months Ended March 31,		
	2013	2012	Change
Gathering and processing fee-based revenues	$97	$70	$27
Non fee-based contracts and processing	67	64	3
Other	(7)	(7)	—
Total gross margin	$157	$127	$30

For the three months ended March 31, 2013 compared to the same period last year, midstream gross margin increased between the periods due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased production in the Eagle Ford Shale resulted in increased fee-based revenues of $22 million. Additional volumes from the Woodford Shale also increased gross margin from our North Texas system by $3 million. The consolidation of Southern Union's gathering and processing segment also increased gross margin by $5 million. These increases were partially offset by a decline of $3 million on our Southeast Texas system as production shifted to the Eagle Ford Shale.
- Non fee-based contracts and processing. Our non fee-based gross margins increased $3 million primarily due to the consolidated of Southern Union’s gathering and processing segment, which contributed $22 million during the three months ended March 31, 2013. The composite NGL price decreased to $0.86 per gallon for the three months ended March 31, 2013 from $1.17 per gallon during the same period last year causing non fee-based margins to decrease by $19 million between the periods.

Table of Contents

- Other midstream gross margin. Other midstream gross margin included fees charged by our intrastate transportation systems, which were recognized as income by our intrastate transportation and storage segment and eliminated in our consolidated results of operations.

Unrealized Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized losses associated with our marketing and NGL hedging activities of less than $1 million during the three months ended March 31, 2013 compared to unrealized losses of $2 million in the same period last year, mainly due to lower notional volumes hedged and price movements.

Operating Expenses, Excluding Non-Cash Compensation Expense. Substantially all of the increase in midstream operating expenses for the three months ended March 31, 2013 compared to the same period last year was due to the consolidation of Southern Union's gathering and processing operations beginning March 26, 2012.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased for the three months ended March 31, 2013 compared to the same period last year primarily due to the consolidation of Southern Union's gathering and processing operations beginning March 26, 2012.

NGL Transportation and Services

	Three Months Ended March 31,		
	2013	2012	Change
NGL transportation volumes (Bbls/d)	274,030	150,881	123,149
NGL fractionation volumes (Bbls/d)	86,703	20,006	66,697
Revenues	$365	$167	$198
Cost of products sold	257	98	159
Gross margin	108	69	39
Operating expenses, excluding non-cash compensation expense	(19)	(14)	(5)
Selling, general and administrative expenses, excluding non-cash compensation expense	(10)	(5)	(5)
Adjusted EBITDA related to unconsolidated affiliates	1	—	1
Segment Adjusted EBITDA	$80	$50	$30

Volumes. NGL transportation volumes increased on our wholly-owned and joint venture NGL pipelines due to the completion of the Gateway and Justice pipelines in December 2012 and additional volumes from the startup of our Jackson and Kenedy processing plants in February 2013 and December 2012, respectively. Average daily fractionated volumes, including all physical and contractual volumes where we collected a fractionation fee, increased due to the commissioning of our fractionator at Mont Belvieu, Texas in December 2012.

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

	Three Months Ended March 31,		
	2013	2012	Change
Storage margin	$32	$32	$—
Transportation margin	41	13	28
Processing and fractionation margin	34	24	10
Other margin	1	—	1
Total gross margin	$108	$69	$39

NGL transportation and services segment gross margin increased between the periods due to the following:

- Transportation margin. Transportation margin increased due to an increase in volumes transported out of West Texas due to the commissioning of Lone Star's Gateway pipeline during the fourth quarter of 2012. A higher concentration of volumes sourced from transportation contracts originating in West Texas and renegotiated contracts on the East side of the legacy Lone Star pipeline system increased our average realized rate. These volume and rate factors increases on our Lone Star pipeline system accounted for $21 million of the increase in transportation margin between the periods. The completion of our Justice

Table of Contents

pipeline connection to Mont Belvieu, Texas and additional NGL production from our processing plants accounted for the remainder of the increase in transportation margin.

- Processing and fractionation margin. Processing and fractionation margin increased due to the startup of Lone Star's fractionator at Mont Belvieu, Texas in December 2012, which contributed $16 million during the three months ended March 31, 2013. The increase in margin related to our fractionator was offset by a decrease in margin attributable to our fractionator in Geismar, Louisiana due to a less favorable pricing environment and contract mix.
- Other margin. Other margin included storage optimization and fractionator off-take agreements, for which there was no comparable activity in the same period last year.

Operating Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services operating expenses increased for the three months ended March 31, 2013 compared to the same period last year primarily due to increases in ad valorem taxes of $3 million and incremental expenses related to the start-up of Lone Star's fractionator.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services selling, general and administrative expenses increased for the three months ended March 31, 2013 compared to the same period last year primarily due to an increase in employee-related costs and allocated overhead expenses due to the overall asset growth on the system.

Investment in Sunoco Logistics

	Three Months Ended March 31,		
	2013	2012	Change
Revenue	$3,512	$—	$3,512
Cost of products sold	3,226	—	3,226
Gross margin	286	—	286
Unrealized gains on commodity risk management activities	(3)	—	(3)
Operating expenses, excluding non-cash compensation expense	(24)	—	(24)
Selling, general and administrative expenses, excluding non-cash compensation expense	(30)	—	(30)
Adjusted EBITDA related to unconsolidated affiliates	7	—	7
Segment Adjusted EBITDA	$236	$—	$236

We obtained control of Sunoco Logistics on October 5, 2012 in connection with our acquisition of Sunoco; therefore, no comparative results were reflected in our financial statements.

Retail Marketing

	Three Months Ended March 31,		
	2013	2012	Change
Total retail gasoline outlets, end of period	4,979	—	4,979
Total company-operated outlets, end of period	439	—	439
Gasoline and diesel throughput per company-operated site (gallons/month)	187,000	—	187,000
Revenue	$5,222	$—	$5,222
Cost of products sold	5,036	—	5,036
Gross margin	186	—	186
Operating expenses, excluding non-cash compensation expense	(98)	—	(98)
Selling, general and administrative expenses, excluding non-cash compensation expense	(15)	—	(15)
LIFO valuation adjustment	(38)	—	(38)
Adjusted EBITDA related to unconsolidated affiliates	2	—	2
Segment Adjusted EBITDA	$37	$—	$37

Table of Contents

We acquired our retail marketing segment on October 5, 2012 in connection with our acquisition of Sunoco; therefore, no comparative results were reflected in our financial statements.

All Other

	Three Months Ended March 31,		
	2013	2012	Change
Revenue	$150	$129	$21
Cost of products sold	137	91	46
Gross margin	13	38	(25)
Unrealized (gains) losses on commodity risk management activities	(4)	2	(6)
Operating expenses, excluding non-cash compensation expense	(5)	(20)	15
Selling, general and administrative expenses, excluding non-cash compensation expense	(18)	(13)	(5)
Adjusted EBITDA attributable to discontinued operations	40	2	38
Adjusted EBITDA related to unconsolidated affiliates	76	75	1
Elimination	(7)	(1)	(6)
Segment Adjusted EBITDA	$95	$83	$12

Amounts reflected in our all other segment primarily include:

- Our retail propane and other retail propane related operations prior to our contribution of those operations to AmeriGas in January 2012. Our investment in AmeriGas was reflected in the all other segment subsequent to that transaction;
- Southern Union’s local distribution operations beginning March 26, 2012;
- Our natural gas compression operations; and,
- An approximate 30% non-operating interest in PES, a refining joint venture, effective upon our acquisition of Sunoco on October 5, 2012.

The decrease in gross margin and operating expenses is primarily due to our recognition of $31 million of gross margin and $18 million of operating expenses from our retail propane operations prior to the deconsolidation of those operations in January 2012. We also recognized $1 million of selling, general and administrative expenses from our retail propane operations prior to the deconsolidation in January 2012; however, the impact from the deconsolidation was more than offset by the recognition of additional selling, general and administrative expenses related to Sunoco in the three months ended March 31, 2013.

Adjusted EBITDA attributable to discontinued operations reflected the results of Southern Union's local distribution operations. Adjusted EBITDA related to unconsolidated affiliates reflected the results from our investments in AmeriGas and PES. Additional information related to unconsolidated affiliates is provided above in “Supplemental Information on Unconsolidated Affiliates.”

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 expect the following capital expenditures for the remainder of 2013:

	Growth		Maintenance	
	Low	High	Low	High
ETP legacy assets:				
Midstream and intrastate transportation and storage	$200	$240	$65	$75
NGL transportation and services[(1)]	440	500	10	20
Interstate transportation and storage	10	20	15	25
	650	760	90	120
Holdco:				
Southern Union transportation and storage	30	40	90	100
Retail marketing	20	50	55	65
	50	90	145	165
Investment in Sunoco Logistics	500	600	55	65
Total projected capital expenditures	$1,200	$1,450	$290	$350

(1) We expect to receive capital contributions from Regency related to their 30% share of Lone Star of $100 million.

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 the ETP 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 the ETP Credit Facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2013; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Cash Flows

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

Operating Activities

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

Three months ended March 31, 2013 compared to three months ended March 31, 2012. Cash provided by operating activities during 2013 was $353 million compared to $60 million for 2012 and net income was $424 million and $1.09

billion for 2013 and 2012, respectively. The difference between net income and cash provided by operating activities for the three months ended March 31, 2013 primarily consisted of net changes in operating assets and liabilities of $303 million and non-cash items totaling $155 million.

The non-cash activity in 2013 and 2012 consisted primarily of depreciation and amortization of $260 million and $99 million, respectively, and non-cash compensation expense of $14 million and $11 million, respectively.
Cash paid for interest, net of interest capitalized, was $248 million and $134 million for the three months ended March 31, 2013 and 2012, respectively.
Investing Activities
Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, cash distributions from our joint ventures, and cash proceeds from the contribution of the Propane Business in 2012. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.
Three months ended March 31, 2013 compared to three months ended March 31, 2012. Cash used in investing activities during 2013 was $559 million compared to $538 million for 2012. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2013 were $595 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2012 of $521 million. Additional detail related to our capital expenditures is provided in the table below. In addition, in 2012 we paid net cash for acquisitions of $1.42 billion, primarily for the Citrus Merger. We also received net cash proceeds of $1.38 billion from the contribution of the Propane Business in 2012.
The following is a summary of capital expenditures for the three months ended March 31, 2013:

	Capital Expenditures Recorded During Period			(Increase)Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
ETP legacy assets:					
Intrastate transportation and storage	$2	$3	$5	$ (2)	$3
Interstate transportation and storage	2	3	5	12	17
Midstream	113	5	118	27	145
NGL transportation and services	102	3	105	21	126
	219	14	233	58	291
Holdco:					
Southern Union transportation and storage	—	(1)	(1)	15	14
Southern Union gathering and processing	80	7	87	9	96
Retail marketing	6	10	16	8	24
	86	16	102	32	134
Investment in Sunoco Logistics	136	4	140	14	154
All other (including eliminations)	(6)	17	11	5	16
Total	$435	$51	$486	$ 109	$595

Financing Activities
Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.
Three months ended March 31, 2013 compared to three months ended March 31, 2012. Cash provided by financing activities during 2013 was $423 million compared to $540 million for 2012. In 2013, we received net proceeds from Common Unit offerings of $192 million compared to $87 million in 2012. During 2013, we had a net increase in our debt level of $728 million compared to a net increase of $731 million for 2012. We incurred debt issuance costs of $16 million in 2013 compared to $20 million in 2012. We paid distributions of $391 million to our partners in 2013

compared to $318 million in 2012. In addition, we received capital contributions of $42 million from Regency for its noncontrolling interest in Lone Star compared to $67 million in 2012.

Table of Contents

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	March 31, 2013	December 31, 2012
ETP Debt	$9,165	$9,073
Transwestern Debt	869	869
Southern Union Debt	1,556	1,526
Panhandle Debt	1,748	1,757
Sunoco Debt	1,085	1,094
Sunoco Logistics Debt	2,318	1,732
Note Payable to ETE	166	166
Total	16,907	16,217
Less: current maturities	(606)	(609)
Long-term debt and notes payable, less current maturities	$16,301	$15,608

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, 2012, filed with the SEC on March 1, 2013 and in Note 8 to our consolidated financial statements.

Credit Facilities

ETP Credit Facility

ETP has a $2.5 billion revolving credit facility, the ETP Credit Facility, that expires in October 2016. Indebtedness under 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.

As of March 31, 2013, we had $250 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $2.17 billion after taking into account letters of credit of $76 million. The weighted average interest rate on the total amount outstanding as of March 31, 2013 was 1.70%.

Southern Union Credit Facility

The Southern Union Credit Facility provides for borrowings of up to $700 million and expires in May 2016. Borrowings under the Southern Union Credit Facility are available for working capital, other general company purposes and letter of credit requirements. Outstanding borrowings under the Southern Union Credit Facility were $240 million as of March 31, 2013. The weighted average interest rate on the total amount outstanding as of March 31, 2013 was 1.83%.

In connection with the SUGS Contribution, borrowings under the Southern Union Credit Facility were repaid and the facility was terminated.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains two credit facilities to fund its working capital requirements, finance acquisitions and capital projects and for general partnership purposes. The credit facilities consist of a $350 million unsecured credit facility which expires in August 2016 (the "$350 million Credit Facility") and a $200 million unsecured credit facility which expires in August 2013 (the "$200 million Credit Facility"). There were no outstanding borrowings under the $350 million Credit Facility and the $200 million Credit Facility as of March 31, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving credit facility. Outstanding borrowings under this credit facility were $33 million as of March 31, 2013.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of March 31, 2013.

Table of Contents

Cash Distributions

Cash Distributions Paid by ETP

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, 2012:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 7, 2013	February 14, 2013	$0.89375
March 31, 2013	May 6, 2013	May 15, 2013	0.89375

The total amounts of distributions declared during the three months ended March 31, 2013 and 2012 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Three Months Ended March 31,	
	2013	2012
Limited Partners:		
Common Units	$286	$205
Class E Units	3	3
Class G Units	85	—
General Partner interest	5	5
IDRs	125	100
Total distributions declared	$504	$313

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to $220 million of distributions associated with the IDRs from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters. In addition, under the terms of the Holdco transaction agreement, ETE will relinquish an aggregate of $210 million of incentive distributions over 12 consecutive quarters following the closing of the Holdco Transaction. The distributions reflected above for the three months ended March 31, 2013 and 2012 reflect IDR reductions totaling $31 million and $14 million, respectively, which includes one quarter of IDR relinquishment related to the Citrus Merger and one quarter related to the Holdco Transaction for 2013 and one quarter of IDR relinquishment related to the Citrus Merger for 2012.

Cash Distributions Paid by Subsidiaries

Sunoco Logistics is required by its partnership agreement to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by its general partner.

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2012:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$0.54500
March 31, 2013	May 9, 2013	May 15, 2013	0.57250

Table of Contents

The total amounts of Sunoco Logistics distributions declared during the three months ended March 31, 2013 were as follows (all from Available Cash from Sunoco Logistics' operating surplus and are shown in the period with respect to which they relate):

	Three Months Ended March 31, 2013
Limited Partners:	
Common Units	$59
General Partner interest	1
IDRs	25
Total distributions declared	$85

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, 2012 filed with the SEC on March 1, 2013.

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, 2012, 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, 2012. Since December 31, 2012, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of March 31, 2013 and December 31, 2012, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Dollar amounts are presented in millions.

Table of Contents

	March 31, 2013			December 31, 2012		
	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 (MMBtu):						
Basis Swaps IFERC/NYMEX [(1)]	3,057,500	$(4)	$—	(30,980,000)	$(6)	$—
Power (Megawatt):						
Forwards	311,150	2	1	19,650	—	1
Futures	(452,400)	(1)	—	(1,509,300)	(1)	1
Options — Calls	57,600	3	1	1,656,400	2	1
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(1,867,500)	(1)	—	150,000	(1)	—
Swing Swaps IFERC	(11,755,000)	—	—	(83,292,500)	1	1
Fixed Swaps/Futures	(6,065,000)	7	11	27,077,500	(7)	9
Forward Physical Contracts	2,021,900	1	—	11,689,855	—	2
Natural Gas Liquid (Bbls):						
Forwards/Swaps	(205,000)	—	1	(30,000)	—	—
Refined Products (Bbls) — Futures	1,772	1	35	(666,000)	(3)	14
Crude (Bbls) — Futures	(120,000)	—	1	—	—	—
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(6,960,000)	—	—	(18,655,000)	(1)	—
Fixed Swaps/Futures	(7,260,000)	(4)	3	(44,272,500)	4	15
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(3,437,500)	—	—	—	—	—
Fixed Swaps/Futures	(9,625,000)	(7)	4	(8,212,500)	(3)	3
Natural Gas Liquid (Bbls):						
Forwards/Swaps	(695,000)	3	4	(930,000)	(2)	7
Refined Products (Bbls) — Futures	—	—	—	(98,000)	—	1
Crude (Bbls) — Futures	(270,000)	(1)	2	—	—	—

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

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

53

Table of Contents

Interest Rate Risk

As of March 31, 2013, we had $1.75 billion 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 $18 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.

The following table summarizes our interest rate swaps outstanding (dollars in millions), none of which are designated as hedges for accounting purposes:

Entity	Term	Type [1]	Notional Amount Outstanding March 31, 2013	Notional Amount Outstanding December 31, 2012
ETP	July 2013[2]	Forward-starting to pay a fixed rate of 4.02% and receive a floating rate	$400	$400
ETP	July 2014[2]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	January 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	200	—
Southern Union	November 2016	Pay a fixed rate of 2.91% and receive a floating rate	75	75
Southern Union	November 2021	Pay a fixed rate of 3.75% and receive a floating rate	450	450

(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 interest rate derivatives) of $33 million and $52 million as of March 31, 2013 and December 31, 2012, respectively. For the $800 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 of $8 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. For Southern Union's interest rate swaps, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $5 million.

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 March 31, 2013 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

During the three months ended March 31, 2013, Southern Union's accounting systems were transitioned to the accounting systems of ETP and ETE and accordingly certain controls changed at that time. None of these changes are in response to any identified deficiency or weakness in internal control over financial reporting.

There have been no other changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended March 31, 2013 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, 2012 and Note 12 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2013.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors described in Part I, Item 1A in our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2012.

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
(*)	10.1	Amended and Restated Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan
(*)	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, 2013 and December 31, 2012; (ii) our Consolidated Statements of Operations for the three months ended March 31, 2013 and 2012; (iii) our Consolidated Statements of Comprehensive Income for the three months ended March 31, 2013 and 2012; (iv) our Consolidated Statement of Partners' Capital for the three months ended March 31, 2013; (v) our Consolidated Statements of Cash Flows for the three months ended March 31, 2013 and 2012; and (vi) the notes to our Consolidated Financial Statements.

* Filed herewith.

** Furnished herewith.

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: May 9, 2013

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