Energy Transfer Partners, L.P.
Form 10-Q
August 07, 2015

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 June 30, 2015

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	73-1493906
(State or other jurisdiction of incorporation or organization)	(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 July 31, 2015, the registrant had 509,952,838 Common Units outstanding.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (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,” “estimate,” “goal,” “ “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, 2014 filed with the Securities and Exchange Commission on March 2, 2015.

Definitions

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

/d	per day
Aqua – PVR	Aqua – PVR Water Services, LLC
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Bbls	barrels
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, LLC
CrossCountry	CrossCountry Energy, LLC
ELG	Edwards Lime Gathering LLC
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
ETE Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP Credit Facility	ETP’s $3.75 billion revolving credit facility
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP Holdco	ETP Holdco Corporation
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
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
HPC	RIGS Haynesville Partnership Co. and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	incentive distribution rights
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a subsidiary of ETE
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lone Star	Lone Star NGL LLC
MEP	Midcontinent Express Pipeline 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
ORS	Ohio River System LLC
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings LLC, a joint venture between subsidiaries of ETC OLP and Sunoco, Inc.

Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Sunoco GP	Sunoco GP LLC, the general partner of Sunoco LP
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco LP	Sunoco LP (previously named Susser Petroleum Partners, LP)
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Susser	Susser Holdings Corporation
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle

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 and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include 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.

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PART I – FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	June 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,615	$663
Accounts receivable, net	3,168	3,360
Accounts receivable from related companies	201	139
Inventories	1,851	1,460
Exchanges receivable	57	44
Derivative assets	6	81
Other current assets	361	296
Total current assets	7,259	6,043
Property, plant and equipment	48,099	43,404
Accumulated depreciation and depletion	(5,242)	(4,497)
	42,857	38,907
Advances to and investments in unconsolidated affiliates	3,667	3,760
Non-current derivative assets	1	10
Other non-current assets, net	801	786
Intangible assets, net	5,526	5,526
Goodwill	7,440	7,642
Total assets	$67,551	$62,674

The accompanying notes are an integral part of these consolidated financial statements.
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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	June 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$3,005	$3,348
Accounts payable to related companies	10	25
Exchanges payable	136	183
Derivative liabilities	12	21
Accrued and other current liabilities	1,983	2,099
Current maturities of long-term debt	15	1,008
Total current liabilities	5,161	6,684
Long-term debt, less current maturities	29,058	24,973
Non-current derivative liabilities	109	154
Deferred income taxes	4,104	4,246
Other non-current liabilities	1,220	1,258
Commitments and contingencies		
Series A Preferred Units	33	33
Redeemable noncontrolling interests	15	15
EQUITY:		
General Partner	294	184
Limited Partners:		
Common Unitholders	17,541	10,430
Class H Unitholder	3,460	1,512
Class I Unitholder	32	—
Accumulated other comprehensive loss	(14)	(56)
Total partners’ capital	21,313	12,070
Noncontrolling interest	6,538	5,153
Predecessor equity	—	8,088
Total equity	27,851	25,311
Total liabilities and equity	$67,551	$62,674

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Natural gas sales	$899	$1,361	$1,933	$2,791
NGL sales	988	1,400	1,969	2,654
Crude sales	2,680	4,432	4,888	8,525
Gathering, transportation and other fees	980	823	1,973	1,642
Refined product sales	4,434	4,938	8,090	9,416
Other	1,559	1,134	3,013	2,087
Total revenues	11,540	14,088	21,866	27,115
COSTS AND EXPENSES				
Cost of products sold	9,338	12,352	17,825	23,794
Operating expenses	651	417	1,270	831
Depreciation, depletion and amortization	501	436	980	796
Selling, general and administrative	162	115	295	220
Total costs and expenses	10,652	13,320	20,370	25,641
OPERATING INCOME	888	768	1,496	1,474
OTHER INCOME (EXPENSE)				
Interest expense, net of interest capitalized	(336)	(295)	(646)	(569)
Equity in earnings of unconsolidated affiliates	117	77	174	181
Gain on sale of AmeriGas common units	—	93	—	163
Gains (losses) on interest rate derivatives	127	(46)	50	(48)
Other, net	(16)	(21)	(9)	(21)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	780	576	1,065	1,180
Income tax expense (benefit) from continuing operations	(59)	71	(42)	216
INCOME FROM CONTINUING OPERATIONS	839	505	1,107	964
Income from discontinued operations	—	42	—	66
NET INCOME	839	547	1,107	1,030
Less: Net income attributable to noncontrolling interest	212	87	206	141
Less: Net income (loss) attributable to predecessor	(27)	(11)	(34)	3
NET INCOME ATTRIBUTABLE TO PARTNERS	654	471	935	886
General Partner’s interest in net income	260	125	502	238
Class H Unitholder’s interest in net income	64	51	118	100
Class I Unitholder’s interest in net income	32	—	65	—
Common Unitholders’ interest in net income	$298	$295	$250	$548
INCOME FROM CONTINUING OPERATIONS PER COMMON UNIT:				
Basic	$0.67	$0.79	$0.63	$1.47
Diluted	$0.67	$0.79	$0.63	$1.47
NET INCOME PER COMMON UNIT:				
Basic	$0.67	$0.92	$0.63	$1.67

Diluted	$0.67	$0.92	$0.63	$1.67

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income	$839	$547	$1,107	$1,030
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	—	2	—	6
Change in value of derivative instruments accounted for as cash flow hedges	—	(2)	1	(6)
Change in value of available-for-sale securities	(1)	—	—	—
Actuarial gain (loss) relating to pension and other postretirement benefit plans	—	—	45	(1)
Foreign currency translation adjustments	—	1	(2)	(2)
Change in other comprehensive income from unconsolidated affiliates	—	1	(2)	(6)
	(1)	2	42	(9)
Comprehensive income	838	549	1,149	1,021
Less: Comprehensive income attributable to noncontrolling interest	212	87	206	141
Less: Comprehensive income (loss) attributable to predecessor	(27)	(11)	(34)	3
Comprehensive income attributable to partners	$653	$473	$977	$877

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2015
(Dollars in millions)
(unaudited)

		Limited Partners						
	General Partner	Common Units	Class H Units	Class I Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Predecessor Equity	Total
Balance, December 31, 2014	$184	$10,430	$1,512	$—	$ (56)	$ 5,153	$ 8,088	$25,311
Distributions to partners	(393)	(842)	(116)	(33)	—	—	—	(1,384)
Predecessor distributions to partners	—	—	—	—	—	—	(202)	(202)
Distributions to noncontrolling interest	—	—	—	—	—	(165)	—	(165)
Units issued for cash	—	724	—	—	—	—	—	724
Subsidiary units issued for cash	1	101	—	—	—	911	—	1,013
Predecessor units issued for cash	—	—	—	—	—	—	34	34
Capital contributions from noncontrolling interest	—	—	—	—	—	398	—	398
Other comprehensive income, net of tax	—	—	—	—	42	—	—	42
Regency Merger	—	7,890	—	—	—	—	(7,890)	—
Bakken Pipeline Transaction	—	(999)	1,946	—	—	72	—	1,019
Sale of noncontrolling interest in Rover Pipeline LLC to AE–Midco Rover, LLC	—	4	—	—	—	60	—	64
Sunoco Logistics acquisition of noncontrolling interest	—	(30)	—	—	—	(99)	—	(129)
Other, net	—	13	—	—	—	2	4	19
Net income (loss)	502	250	118	65	—	206	(34)	1,107

Balance, June 30, 2015	$294	$17,541	$3,460	$32	$ (14)	$ 6,538	$ —	$27,851

The accompanying notes are an integral part of these consolidated financial statements.
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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)
(unaudited)

	Six Months Ended June 30, 2015	2014
OPERATING ACTIVITIES		
Net income	$1,107	$1,030
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	980	796
Deferred income taxes	79	(112)
Amortization included in interest expense	(21)	(33)
Inventory valuation adjustments	(150)	(34)
Non-cash compensation expense	43	32
Gain on sale of AmeriGas common units	—	(163)
Loss on extinguishment of debt	32	—
Distributions on unvested awards	(7)	(8)
Equity in earnings of unconsolidated affiliates	(174)	(181)
Distributions from unconsolidated affiliates	162	143
Other non-cash	20	(39)
Cash flow in operating assets and liabilities, net of effects of acquisitions and deconsolidations	(938)	361
Net cash provided by operating activities	1,133	1,792
INVESTING ACTIVITIES		
Cash proceeds from Bakken Pipeline Transaction	980	—
Cash proceeds from sale of noncontrolling interest in Rover Pipeline LLC to AE–Midco Rover, LLC	64	—
Cash proceeds from the sale of AmeriGas common units	—	759
Cash paid for acquisition of a noncontrolling interest	(129)	—
Cash paid for all other acquisitions	(475)	(407)
Capital expenditures (excluding allowance for equity funds used during construction)	(4,143)	(2,104)
Contributions in aid of construction costs	12	25
Contributions to unconsolidated affiliates	(43)	(63)
Distributions from unconsolidated affiliates in excess of cumulative earnings	64	58
Proceeds from sale of discontinued operations	—	79
Proceeds from the sale of assets	15	18
Change in restricted cash	8	7
Other	(9)	—
Net cash used in investing activities	(3,656)	(1,628)
FINANCING ACTIVITIES		
Proceeds from borrowings	12,494	5,633
Repayments of long-term debt	(9,386)	(4,913)
Net proceeds from issuance of Common Units	724	484
Subsidiary equity offerings, net of issue costs	1,013	102
Predecessor equity offerings, net of issue costs	34	465
Capital contributions received from noncontrolling interest	398	6
Distributions to partners	(1,384)	(943)
Predecessor distributions to partners	(202)	(256)

Distributions to noncontrolling interest	(165)	(108)
Debt issuance costs	(50)	(30)
Other	(1)	(2)
Net cash provided by financing activities	3,475	438
Increase in cash and cash equivalents	952	602
Cash and cash equivalents, beginning of period	663	568
Cash and cash equivalents, end of period	$1,615	$1,170

The accompanying notes are an integral part of these consolidated financial statements.
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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts, except per unit data, are in millions)
(unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Energy Transfer Partners, L.P., a publicly traded Delaware master limited partnership, and its subsidiaries (collectively, the "Partnership," "we," "us," "our" or "ETP") are managed by our 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 consolidated financial statements of the Partnership presented herein include our operating subsidiaries described below.

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

- ETC OLP, a Texas limited partnership primarily 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. ETC OLP's 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. ETC OLP's 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. Subsequent to its acquisition of Regency's 30% equity interest in Lone Star, as discussed below, ETC OLP now owns 100% of 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.
- ETP Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco, Inc. Panhandle and Sunoco, Inc. operations are described as follows:
- Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States.
- Sunoco, Inc. owns and operates retail marketing assets, which sell gasoline and middle distillates at retail locations and operates convenience stores primarily on the east coast and in the midwest region of the United States. Effective June 1, 2014, the Partnership combined certain Sunoco, Inc. retail assets with another wholly-owned subsidiary of ETP to form a limited liability company, Retail Holdings, owned by ETP and Sunoco, Inc.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of products, crude oil and NGL pipelines, terminalling and storage assets, and refined products, crude oil and NGL acquisition and marketing assets.
- As of June 30, 2015, ETP owned an indirect 100% equity interest in Susser and the general partner interest, incentive distribution rights and a 44% limited partner interest in Sunoco LP. As discussed in Note 2, in July 2015, ETP transferred its interest in Susser to Sunoco LP in exchange for cash and additional interests in Sunoco LP. Susser operates convenience stores in Texas, New Mexico and Oklahoma. Sunoco LP, is a publicly

traded Delaware limited partnership that distributes motor fuels to convenience stores and retail fuel outlets in Texas, New Mexico, Oklahoma, Kansas, Louisiana, Maryland, Virginia, Tennessee, Georgia and Hawaii and other commercial customers. These operations are reported within the retail marketing segment.

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• Regency is a limited partnership engaged in the gathering and processing, compression, treating and transportation of natural gas; the gathering, transportation and terminalling of oil (crude and/or condensate, a lighter oil) received from producers; and the management of coal and natural resource properties in the United States. Regency focuses on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring, Avalon and Granite Wash shales.

Our financial statements reflect the following reportable business segments:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- liquids transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and
- all other.

Basis of Presentation

The unaudited financial information included in this Form 10-Q has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014, except that the consolidated financial statements have been retrospectively adjusted to reflect the consolidation of Regency, as discussed below. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

Merger with Regency. On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency, with Regency continuing as the surviving entity (the "Regency Merger"). Each Regency common unit and Class F unit was converted into the right to receive 0.4124 Partnership common units. ETP issued 172.2 million Partnership common units to Regency unitholders, including 15.5 million units issued to Partnership subsidiaries. The 1.9 million outstanding Regency series A preferred units were converted into corresponding new Partnership Series A Preferred Units on a one-for-one basis.

In connection with the Regency Merger, ETE will reduce the incentive distributions it receives from the Partnership by a total of $320 million over a five-year period. The IDR subsidy will be $80 million in the first year post-closing and $60 million per year for the following four years.

The Regency Merger was a combination of entities under common control; therefore Regency's assets and liabilities were not adjusted. The Partnership's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner). Predecessor equity included on the consolidated financial statements represents Regency's equity prior to the Regency Merger.

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The following table presents the revenues and net income for the previously separate entities and the combined amounts presented herein:

	Three Months Ended June 30, 2015 [(1)]	2014	Six Months Ended June 30, 2015 [(1)]	2014
Revenues:				
Partnership	$11,253	$13,029	$20,783	$25,261
Regency	301	1,178	1,300	2,041
Adjustments and eliminations	(14)	(119)	(217)	(187)
Combined	$11,540	$14,088	$21,866	$27,115
Net income (loss):				
Partnership	$881	$581	$1,189	$1,072
Regency	(26)	(4)	(29)	8
Adjustments and eliminations	(16)	(30)	(53)	(50)
Combined	$839	$547	$1,107	$1,030

(1) Amounts attributable to Regency subsequent to the Regency Merger on April 30, 2015 are reflected in the Partnership amounts.

Use of Estimates

Certain prior period amounts have been reclassified to conform to the 2015 presentation. These reclassifications had no impact on net income or total equity.

The unaudited consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions made by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the consolidated financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Excise Taxes

The Partnership records the collection of taxes to be remitted to government authorities on a net basis except for the retail marketing segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and cost of products sold in the consolidated statements of operations, with no net impact on net income. Excise taxes collected by the retail marketing segment were $762 million and $573 million for the three months ended June 30, 2015 and 2014, respectively, and $1.50 billion and $1.10 billion for the six months ended June 30, 2015 and 2014, respectively.

Subsidiary Common Unit Transactions. The Partnership accounts for the difference between the carrying amount of investments in Sunoco Logistics and Sunoco LP and the underlying book value arising from the issuance or redemption of units by the respective subsidiary (excluding transactions with us) as capital transactions.

Recent Accounting Pronouncement. In February 2015, the FASB issued Accounting Standards Update No. 2015-02, Consolidation (Topic 810) ("ASU 2015-02"), which changed the requirements for consolidations analysis. Under ASU 2015-02, reporting entities are required to evaluate whether they should consolidate certain legal entities. ASU 2015-02 is effective for fiscal years beginning after December 15, 2015, and early adoption is permitted. The Partnership expects to adopt this standard for the year ending December 31, 2016, and we are currently evaluating the impact that it will have on the consolidated financial statements and related disclosures.

2. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS

Sunoco LP

In April 2015, Sunoco LP acquired a 31.58% equity interest in Sunoco, LLC from Retail Holdings for $816 million. Sunoco, LLC distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest

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regions of the United States. Sunoco LP paid $775 million in cash and issued $41 million of Sunoco LP common units to Retail Holdings, based on the five-day volume weighted average price of Sunoco LP's common units as of March 20, 2015.

In July 2015, Sunoco LP acquired 100% of Susser from ETP in a transaction valued at $1.93 billion. Sunoco LP paid approximately $967 million in cash and issued 22 million Sunoco LP common units, valued at approximately $967 million, to ETP. In addition, there will be an exchange for 11 million Sunoco LP units owned by Susser for another 11 million new Sunoco LP units to a subsidiary of ETP.

In July 2015, ETE entered into an exchange and repurchase agreement with ETP, pursuant to which ETE would acquire 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, in exchange for the repurchase of 21 million ETP common units owned by ETE. In connection with ETP's 2014 acquisition of Susser, ETE agreed to provide ETP a $35 million annual IDR subsidy for 10 years, which would terminate upon the closing of ETE's acquisition of Sunoco GP. In connection with the exchange and repurchase, ETE agreed to provide ETP a $35 million annual IDR subsidy for two years. Following this transaction, Sunoco LP will no longer be consolidated for accounting purposes by ETP. This transaction is expected to close in August 2015.

Bakken Pipeline

In March 2015, ETE transferred 30.8 million Partnership common units, ETE's 45% interest in the Bakken Pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Partnership Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to ETP. These IDR subsidies, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

Discontinued Operations

Discontinued operations for the six months ended June 30, 2014 includes the results of operations for a marketing business that was sold effective April 1, 2014.

3. CASH AND CASH EQUIVALENTS

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

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

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

	Six Months Ended June 30, 2015	2014
Accounts receivable	$82	$(891)
Accounts receivable from related companies	(53)	(78)
Inventories	(252)	294
Exchanges receivable	(14)	(26)
Other current assets	(96)	340
Other non-current assets, net	99	(25)
Accounts payable	(333)	538
Accounts payable to related companies	(262)	17
Exchanges payable	(47)	(11)
Accrued and other current liabilities	(122)	152
Other non-current liabilities	30	(33)
Derivative assets and liabilities, net	30	84
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$(938)	$361

Non-cash investing and financing activities are as follows:

	Six Months Ended June 30, 2015	2014
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$693	$339
Accrued advances to unconsolidated affiliates	—	175
Net gains from subsidiary common unit issuances	102	14
NON-CASH FINANCING ACTIVITIES:		
Issuance of common units in connection with the Regency Merger	9,250	—
Issuance of Class H Units in connection with the Bakken Pipeline Transaction	1,946	—
Subsidiary issuances of common units in connection with Regency's acquisitions	—	4,015
Long-term debt assumed in Regency's acquisitions	—	1,887
Redemption of common units in connection with the Bakken Pipeline Transaction	999	—
Redemption of common units in connection with the Lake Charles LNG Transaction	—	1,167

4. INVENTORIES

Inventories consisted of the following:

	June 30, 2015	December 31, 2014
Natural gas and NGLs	$425	$392
Crude oil	599	364
Refined products	446	392
Other	381	312
Total inventories	$1,851	$1,460

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We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

5. FAIR VALUE MEASURES

We have commodity derivatives, interest rate derivatives and embedded derivatives in the preferred units 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. Level 3 inputs are unobservable. Derivatives related to the preferred units were valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected value, and are considered Level 3. During the six months ended June 30, 2015, no transfers were made between any levels within the fair value hierarchy.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations at June 30, 2015 was $29.24 billion and $29.07 billion, respectively. As of December 31, 2014, the aggregate fair value and carrying amount of our consolidated debt obligations was $26.91 billion and $25.98 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of June 30, 2015 and December 31, 2014 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2015		
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$1	$—	$1	$—
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	7	7	—	—
Swing Swaps IFERC	2	—	2	—
Fixed Swaps/Futures	213	213	—	—
Forward Physical Swaps	2	—	2	—
Power:				
Forwards	4	—	4	—
Futures	3	3	—	—
Options – Calls	5	5	—	—
Natural Gas Liquids – Forwards/Swaps	31	31	—	—
Refined Products – Futures	6	6	—	—
Total commodity derivatives	273	265	8	—
Total assets	$274	$265	$9	$—
Liabilities:				
Interest rate derivatives	$(105)	$—	$(105)	$—
Embedded derivatives in the ETP Preferred Units	(12)	—	—	(12)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(7)	(7)	—	—
Swing Swaps IFERC	(2)	(1)	(1)	—
Fixed Swaps/Futures	(189)	(189)	—	—
Forward Physical Swaps	(1)	—	(1)	—
Power:				
Forwards	(3)	—	(3)	—
Futures	(7)	(7)	—	—
Options – Puts	(4)	(4)	—	—
Natural Gas Liquids – Forwards/Swaps	(29)	(29)	—	—
Refined Products – Futures	(6)	(6)	—	—
Total commodity derivatives	(248)	(243)	(5)	—
Total liabilities	$(365)	$(243)	$(110)	$(12)

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	Fair Value Total	Fair Value Measurements at December 31, 2014 Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$3	$—	$3	$—
Commodity derivatives:				
Condensate – Forward Swaps	36	—	36	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	19	19	—	—
Swing Swaps IFERC	26	1	25	—
Fixed Swaps/Futures	566	541	25	—
Forward Physical Swaps	1	—	1	—
Power:				
Forwards	3	—	3	—
Futures	4	4	—	—
Natural Gas Liquids – Forwards/Swaps	69	46	23	—
Refined Products – Futures	21	21	—	—
Total commodity derivatives	745	632	113	—
Total assets	$748	$632	$116	$—
Liabilities:				
Interest rate derivatives	$(155)	$—	$(155)	$—
Embedded derivatives in the Regency Preferred Units	(16)	—	—	(16)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(18)	(18)	—	—
Swing Swaps IFERC	(25)	(2)	(23)	—
Fixed Swaps/Futures	(490)	(490)	—	—
Power:				
Forwards	(4)	—	(4)	—
Futures	(2)	(2)	—	—
Natural Gas Liquids – Forwards/Swaps	(32)	(32)	—	—
Refined Products – Futures	(7)	(7)	—	—
Total commodity derivatives	(578)	(551)	(27)	—
Total liabilities	$(749)	$(551)	$(182)	$(16)

The following table presents the material unobservable inputs used to estimate the fair value of the Preferred Units and the embedded derivatives in the Preferred Units:

	Unobservable Input	June 30, 2015
Embedded derivatives in the Preferred Units:	Credit spread	3.57%
	Volatility	24.90%

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The following table presents a reconciliation of the beginning and ending balances for our Level 3 financial instruments measured at fair value on a recurring basis using significant unobservable inputs for the six months ended June 30, 2015.

Balance, December 31, 2014	$(16	)
Net unrealized gains included in other income (expense)	4	
Balance, June 30, 2015	$(12	)

6. NET INCOME PER LIMITED PARTNER UNIT

Net income for partners’ capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to the General Partner, the holder of the IDRs pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests. Earnings attributable to predecessor represents amounts allocated to the former Regency partners and have no impact on income from continuing operations per unit for the periods prior to the Regency Merger.

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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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Income from continuing operations	$839	$505	$1,107	$964
Less: Income from continuing operations attributable to noncontrolling interest	212	87	206	141
Less: Income (loss) from continuing operations attributable to predecessor	(27)	(11)	(34)	3
Income from continuing operations, net of noncontrolling interest and predecessor income (loss)	654	429	935	820
General Partner’s interest in income from continuing operations	260	125	502	238
Class H Unitholder’s interest in income from continuing operations	64	51	118	100
Class I Unitholder’s interest in income from continuing operations	32	—	65	—
Common Unitholders’ interest in income from continuing operations	298	253	250	482
Additional earnings allocated from (to) General Partner	(2)	1	(4)	(2)
Distributions on employee unit awards, net of allocation to General Partner	(3)	(3)	(7)	(6)
Income from continuing operations available to Common Unitholders	$293	$251	$239	$474
Weighted average Common Units – basic	434.8	318.5	379.6	321.4
Basic income from continuing operations per Common Unit	$0.67	$0.79	$0.63	$1.47
Dilutive effect of unvested Unit Awards	1.5	1.0	1.5	1.0
Weighted average Common Units, assuming dilutive effect of unvested Unit Awards	436.3	319.5	381.1	322.4
Diluted income from continuing operations per Common Unit	$0.67	$0.79	$0.63	$1.47
Basic income from discontinued operations per Common Unit	$0.00	$0.13	$0.00	$0.20
Diluted income from discontinued operations per Common Unit	$0.00	$0.13	$0.00	$0.20

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7. DEBT OBLIGATIONS

Our debt obligations consist of the following:

	June 30, 2015	December 31, 2014
ETP Senior Notes	$15,640	$10,890
Transwestern Senior Notes	782	782
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	465	715
Sunoco Logistics Senior Notes(1)	3,975	3,975
Sunoco LP Senior Notes	800	—
Regency Senior Notes:		
8.375% Senior Notes due June 1, 2019	—	499
8.375% Senior Notes due June 1, 2020	390	390
5.75% Senior Notes due September 1, 2020	400	400
6.5% Senior Notes due May 15, 2021	400	400
6.5% Senior Notes due July 15, 2021	500	500
5.875% Senior Notes due March 1, 2022	900	900
5.0% Senior Notes due October 1, 2022	700	700
5.5% Senior Notes due April 15, 2023	700	700
4.5% Senior Notes due November 1, 2023	600	600
Revolving credit facilities:		
ETP $3.75 billion Revolving Credit Facility due November 2019	—	570
Sunoco Logistics' subsidiary $35 million Revolving Credit Facility due April 2015	—	35
Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020	550	150
Sunoco LP $1.5 billion Revolving Credit Facility due September 2019	725	683
Regency $2.5 billion Revolving Credit Facility due November 25, 2019(2)	—	1,504
Other long-term debt	202	223
Unamortized premiums, net of discounts and fair value adjustments	259	280
Total debt	29,073	25,981
Less: Current maturities of long-term debt	15	1,008
Long-term debt, less current maturities	$29,058	$24,973

(1) Sunoco Logistics' 6.125% senior notes due May 15, 2016 were classified as long-term debt as of June 30, 2015 as Sunoco Logistics has the ability and the intent to refinance such borrowings on a long-term basis.

(2) On April 30, 2015, in connection with the Regency Merger, the Regency Credit Facility was paid off in full and terminated.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $259 million in unamortized premiums and fair value adjustments:

2015 (remainder)	$15
2016	314
2017	1,228
2018	2,205
2019	1,729
Thereafter	23,323
Total	$28,814

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ETP Senior Notes

In June 2015, ETP issued $650 million aggregate principal amount of 2.50% senior notes due June 2018, $350 million aggregate principal amount of 4.15% senior notes due October 2020, $1.0 billion aggregate principal amount of 4.75% senior notes due January 2026 and $1.0 billion aggregate principal amount of 6.125% senior notes due December 2045. ETP used the net proceeds of $2.98 billion from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

In March 2015, ETP issued $1.0 billion aggregate principal amount of 4.05% senior notes due March 2025, $500 million aggregate principal amount of 4.90% senior notes due March 2035, and $1.0 billion aggregate principal amount of 5.15% senior notes due March 2045. ETP used the $2.48 billion net proceeds from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

Sunoco LP Senior Notes

In April 2015, Sunoco LP issued $800 million aggregate principal amount of 6.375% senior notes due April 2023. The net proceeds from the offering were used to fund the cash portion of the dropdown of Sunoco, LLC interests and to repay outstanding balances under the Sunoco LP revolving credit facility.

In July 2015, Sunoco LP issued $600 million aggregate principal amount of 5.5% senior notes due August 2020. The net proceeds from the offering were used to fund a portion of the cash consideration for Sunoco LP's acquisition of Susser.

Regency Senior Notes

The following table reflects outstanding indebtedness assumed in the Regency Merger:

	April 30, 2015
Regency Senior Notes	$5,088
Regency $2.5 billion Revolving Credit Facility due November 25, 2019[(1)]	—
Unamortized premiums, net of discounts and fair value adjustments	43
Total debt	$5,131

(1) On April 30, 2015, in connection with the Regency Merger, the Regency Credit Facility was paid off in full and terminated.

On June 1, 2015, Regency redeemed all of the outstanding $499 million aggregate principal amount of its 8.375% senior notes due June 2019.

In July 2015, Regency issued notices of redemption to the holders of the $390 million aggregate principal amount of its 8.375% senior notes due June 2020, with a redemption date of August 13, 2015, and the $400 million aggregate principal amount of its 6.50% senior notes due May 2021, with a redemption date of August 10, 2015.

The Regency senior notes were registered under the Securities Act of 1933 (as amended). Regency may redeem some or all of the Regency senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the Regency senior notes. The balance is payable upon maturity and interest is payable semi-annually.

The senior notes issued by Regency are fully and unconditionally guaranteed, on a joint and several basis, by all of Regency's consolidated subsidiaries, except for ELG and its wholly-owned subsidiaries, Aqua – PVR and ORS. As a result, excluding ELG, Aqua – PVR and ORS, the Regency senior notes effectively rank junior to any future indebtedness of Regency's or its subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the Regency senior notes effectively rank junior to all indebtedness and other liabilities of Regency's existing and future subsidiaries.

Panhandle previously agreed to fully and unconditionally guarantee (the "Panhandle Guarantee") all of the payment obligations of Regency and Regency Energy Finance Corp. under their $600 million in aggregate principal amount of 4.50% senior notes due November 2023. On May 28, 2015, ETP entered into a supplemental indenture relating to the senior notes pursuant to which it has agreed to become a co-obligor with respect to the payment obligations thereunder. Accordingly, pursuant to the terms of the senior notes, Panhandle's obligations under the Panhandle Guarantee have been released.

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The Regency senior notes contain various covenants that limit, among other things, Regency's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $3.75 billion and expires in November 2019. The 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 June 30, 2015, the ETP Credit Facility had no outstanding borrowings.

Sunoco Logistics Credit Facilities

In March 2015, Sunoco Logistics amended and restated its $1.5 billion unsecured credit facility, which was scheduled to mature in November 2018. The amended and restated credit facility is a $2.5 billion unsecured revolving credit agreement (the "Sunoco Logistics Credit Facility"), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $3.25 billion under certain conditions. As of June 30, 2015, the Sunoco Logistics Credit Facility had $550 million of outstanding borrowings.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.5 billion revolving credit facility (the "Sunoco LP Credit Facility"), which expires in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP's written request, subject to certain conditions, up to an additional $250 million. As of June 30, 2015, the Sunoco LP Credit Facility had $725 million of outstanding borrowings.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of June 30, 2015.

8. SERIES A PREFERRED UNITS

In connection with the closing of the Regency Merger as discussed in Note 1, 1.9 million of Regency's outstanding series A preferred units were converted into corresponding newly issued ETP Series A Preferred Units (the "Preferred Units") on a one-for-one basis. If outstanding, the Preferred Units are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon and are reflected as long-term liabilities in our consolidated balance sheets. The Preferred Units are entitled to a preferential quarterly cash distribution of $0.445 per Preferred Unit if outstanding on the record dates of the Partnership's common unit distributions. Holders of the Preferred Units can elect to convert the ETP Preferred Units to ETP Common Units at any time in accordance with ETP's partnership agreement. The number of common units issuable upon conversion of the Preferred Units is equal to the issue price of $18.30, plus all accrued but unpaid distributions and interest thereon, divided by the conversion price of $44.37. As of June 30, 2015, the Preferred Units were convertible to 0.9 million ETP Common Units.

9. REDEEMABLE NONCONTROLLING INTERESTS

The noncontrolling interest holders in one of Sunoco Logistics' consolidated subsidiaries have the option to sell their interests to Sunoco Logistics. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable interest on ETP's consolidated balance sheets.

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10. EQUITY

Class H Units and Class I Units

In March 2015, ETE transferred 30.8 million Partnership common units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics. In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to the Partnership. These IDR subsidies, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

The impact of (i) the IDR subsidy adjustments and (ii) the Class I Unit distributions, along with the currently effective IDR subsidies, is included in the table below under "Quarterly Distributions of Available Cash."

ETP Common Unit Activity

The changes in common units during the six months ended June 30, 2015 were as follows:

	Number of Units
Number of common units at December 31, 2014	355.5
Common units issued in connection with Equity Distribution Agreements	10.1
Common units issued in connection with the Distribution Reinvestment Plan	2.8
Common units issued in connection with the Regency Merger	172.2
Common units redeemed in connection with the Bakken Pipeline Transaction	(30.8)
Issuance of common units under equity incentive plans	0.2
Number of common units at June 30, 2015	510.0

During the six months ended June 30, 2015, the Partnership received proceeds of $569 million, net of commissions of $6 million, from the issuance of common units pursuant to equity distribution agreements, which were used for general partnership purposes. As of June 30, 2015, $832 million of the Partnership's common units remained available to be issued under an equity distribution agreement.

During the six months ended June 30, 2015, distributions of $155 million were reinvested under the Distribution Reinvestment Plan resulting in the issuance of 2.8 million common units. As of June 30, 2015, a total of 4.5 million common units remain available to be issued under the existing registration statement in connection with the Distribution Reinvestment Plan.

Sales of Common Units by Sunoco Logistics

In 2014, Sunoco Logistics entered into equity distribution agreements pursuant to which Sunoco Logistics may sell from time to time common units having aggregate offering prices of up to $1.25 billion. During the six months ended June 30, 2015, Sunoco Logistics received proceeds of $385 million, net of commissions of $4 million, which were used for general partnership purposes.

Additionally, Sunoco Logistics completed a public offering of 13.5 million common units for net proceeds of $547 million in March 2015. The net proceeds were used to repay outstanding borrowings under the $2.5 billion Sunoco Logistics Credit Facility and for general partnership purposes. In April 2015, an additional 2.0 million common units were issued for net proceeds of $82 million related to the exercise of an option in connection with the March 2015 offering.

As a result of Sunoco Logistics' issuances of common units during the six months ended June 30, 2015, the Partnership recognized increases in partners' capital of $102 million.

Sales of Common Units by Sunoco LP

In July 2015, Sunoco LP completed an offering of 5.5 million Sunoco LP common units for net proceeds of $213 million. The net proceeds from the offering were used to repay outstanding balances under the Sunoco LP revolving credit facility.

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Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by the Partnership subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 6, 2015	February 13, 2015	$0.9950
March 31, 2015	May 8, 2015	May 15, 2015	1.0150
June 30, 2015	August 6, 2015	August 14, 2015	1.0350

ETE agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units.

	Total Year
2015 (remainder)	$56
2016	137
2017	128
2018	105
2019	95

Sunoco Logistics Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 9, 2015	February 13, 2015	$0.4000
March 31, 2015	May 11, 2015	May 15, 2015	0.4190
June 30, 2015	August 10, 2015	August 14, 2015	0.4380

Sunoco LP Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco LP subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 17, 2015	February 27, 2015	$0.6000
March 31, 2015	May 19, 2015	May 29, 2015	0.6450
June 30, 2015	August 18, 2015	August 28, 2015	0.6934

Accumulated Other Comprehensive Income (Loss)

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

	June 30, 2015	December 31, 2014
Available-for-sale securities	$3	$3
Foreign currency translation adjustment	(5)	(3)
Net loss on commodity related hedges	—	(1)
Actuarial loss related to pensions and other postretirement benefits	(12)	(57)
Investments in unconsolidated affiliates, net	—	2
Total AOCI, net of tax	$(14)	$(56)

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11. INCOME TAXES

For the three and six months ended June 30, 2015, the Partnership's effective income tax rate decreased from the prior year primarily due to lower earnings among the Partnership's consolidated corporate subsidiaries. In addition, the three and six months ended June 30, 2015 also reflect a benefit of $22 million related to the exclusion of a portion of the dividend income received by certain of our consolidated corporate subsidiaries. For the three and six months ended June 30, 2015, the Partnership's income tax expense was favorably impacted by $11 million due to a reduction in the statutory Texas franchise tax rate which was enacted by the Texas legislature during the second quarter of 2015. For the three and six months ended June 30, 2014, the Partnership's income tax expense from continuing operations included unfavorable income tax adjustments of $87 million related to the Lake Charles LNG Transaction, which was treated as a sale for tax purposes.

During the three months ended June 30, 2015, Sunoco, Inc. filed a petition for refund with the United States Court of Federal Claims in response to a notice of disallowance denying previously filed refund claims related to certain government incentive payments. Also, during the same period, Sunoco, Inc. filed amended state income tax returns in material jurisdictions based on the Federal claim. The state refund claim is $87 million ($57 million after Federal taxes). Consistent with treatment of Federal claims, Sunoco, Inc. has established a reserve for the full amount of the increase due to the uncertain nature of the claims.

On July 23, 2015, we reached a final settlement with the Internal Revenue Service ("IRS") with regards to the IRS examination of Southern Union's tax years 2004 through 2009. For the 2006 tax year, the IRS had challenged $545 million of the $690 million deferred gain associated with the like kind exchange involving certain assets of Southern Union's distribution operations and gathering and processing operations. The terms of the settlement specify that our position with regards to the deferred gain on the like kind exchange was materially correct and as a result, we will receive refunds totaling approximately $6 million for the periods under examination.

12. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Certain FDOT/FTE projects have been or are the subject of litigation in Broward County, Florida. On November 16, 2012, FDOT paid to FGT the sum of approximately $100 million, representing the amount of the judgment, plus interest, in a case tried in 2011.

On April 14, 2011, FGT filed suit against the FDOT/FTE and other defendants in Broward County, Florida seeking an injunction and damages as the result of the construction of a mechanically stabilized earth wall and other encroachments in FGT easements as part of FDOT/FTE's I-595 project. On August 21, 2013, FGT and FDOT/FTE entered into a settlement agreement pursuant to which, among other things, FDOT/FTE paid FGT approximately $19 million in September 2013 in settlement of FGT's claims with respect to the I-595 project. The settlement agreement also provided for agreed easement widths for FDOT/FTE right-of-way and for cost sharing between FGT and FDOT/FTE for any future relocations. Also in September 2013, FDOT/FTE paid FGT an additional approximate $1 million for costs related to the aforementioned turnpike/State Road 91 case tried in 2011.

FGT will continue to seek rate recovery in the future for these types of costs to the extent not reimbursed by the FDOT/FTE. There can be no assurance that FGT will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of such reimbursement will fully compensate FGT for its costs.

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETP agreed to provide contingent, residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third party purchasers.

Guarantee of Collection

Panhandle previously guaranteed the collections of the payment of $600 million of Regency 4.50% senior notes due 2023. On May 28, 2015, ETP entered into a supplemental indenture relating to the senior notes pursuant to which it has agreed to become a co-obligor with respect to the payment obligations thereunder. Accordingly, pursuant to the terms of the senior notes, Panhandle’s obligations under the Panhandle Guarantee have been released.

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On April 30, 2015, in connection with the Regency Merger, ETP entered into various supplemental indentures pursuant to which ETP has agreed to fully and unconditionally guarantee all payment obligations of Regency for all of its outstanding senior notes.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas and New Mexico. We commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992. Under the ICA, tariff rates must be just and reasonable and not unduly discriminatory and pipelines may not confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, 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.

Transwestern Rate Case

On October 1, 2014, Transwestern filed a general NGA Section 4 rate case pursuant to the 2011 settlement agreement with its shippers. On December 2, 2014, the FERC issued an order accepting and suspending the rates to be effective April 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in late 2015. On June 22, 2015, Transwestern filed a settlement with the Commission which resolved, or provided for the resolution of all issues set for hearing in the case. The settlement is subject to Commission approval.

FGT Rate Case

On October 31, 2014, FGT filed a general NGA Section 4 rate case pursuant to a 2010 settlement agreement with its shippers. On November 28, 2014, the FERC issued an order accepting and suspending the rates to be effective no earlier than May 1, 2015, subject to refund. Currently a procedural schedule is set with a hearing scheduled in early 2016.

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 2058. The table below reflects rental expense under these operating leases included in operating expenses in the accompanying statements of operations, which include contingent rentals, and rental expense recovered through related sublease rental income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Rental expense[(1)]	$54	$27	$106	$59
Less: Sublease rental income	(4)	(10)	(12)	(18)
Rental expense, net	$50	$17	$94	$41

(1) Includes contingent rentals totaling $6 million and $6 million for the three months ended June 30, 2015 and 2014 and $10 million and $9 million for the six months ended June 30, 2015 and 2014, respectively.

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

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude oil 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.

Regency Merger Litigation

Following the January 26, 2015 announcement of the definitive merger agreement with Regency, purported Regency unitholders filed lawsuits in state and federal courts in Dallas, Texas and Delaware state court asserting claims relating to the proposed transaction.

On February 3, 2015, William Engel and Enno Seago, purported Regency unitholders, filed a class action petition on behalf of Regency's common unitholders and a derivative suit on behalf of Regency in the 162nd Judicial District Court of Dallas County, Texas (the "Engel Lawsuit"). The lawsuit names as defendants the Regency General Partner, the members of the Regency General Partner's board of directors, ETP, ETP GP, ETE, and, as a nominal party, Regency. The Engel Lawsuit alleges that (1) the Regency General Partner's directors breached duties to Regency and the Regency's unitholders by employing a conflicted and unfair process and failing to maximize the merger consideration; (2) the Regency General Partner's directors breached the implied covenant of good faith and fair dealing by engaging in a flawed merger process; and (3) the non-director defendants aided and abetted in these claimed breaches. The plaintiffs seek an injunction preventing the defendants from closing the proposed transaction or an order rescinding the transaction if it has already been completed. The plaintiffs also seek money damages and court costs, including attorney's fees.

On February 9, 2015, Stuart Yeager, a purported Regency unitholder, filed a class action petition on behalf of the Regency's common unitholders and a derivative suit on behalf of Regency in the 134th Judicial District Court of Dallas County, Texas (the "Yeager Lawsuit"). The allegations, claims, and relief sought in the Yeager Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 10, 2015, Lucien Coggia a purported Regency unitholder, filed a class action petition on behalf of Regency's common unitholders and a derivative suit on behalf of Regency in the 192nd Judicial District Court of Dallas County, Texas (the "Coggia Lawsuit"). The allegations, claims, and relief sought in the Coggia Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 3, 2015, Linda Blankman, a purported Regency unitholder, filed a class action complaint on behalf of the Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Blankman Lawsuit"). The allegations and claims in the Blankman Lawsuit are similar to those in the Engel Lawsuit. However, the Blankman Lawsuit does not allege any derivative claims and includes Regency as a defendant rather than a nominal party. The lawsuit also omits one of the Regency General Partner's directors, Richard Brannon, who was named in the Engel Lawsuit. The Blankman Lawsuit alleges that the Regency General Partner's directors breached their fiduciary duties to the unitholders by failing to maximize the value of Regency, failing to properly value Regency, and ignoring conflicts of interest. The plaintiff also asserts a claim against the non-director defendants for aiding and abetting the directors' alleged breach of fiduciary duty. The Blankman Lawsuit seeks the same relief that the plaintiffs seek in the Engel Lawsuit.

On February 6, 2015, Edwin Bazini, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Bazini Lawsuit"). The allegations, claims, and relief sought in the Bazini Lawsuit are nearly identical to those in the Blankman Lawsuit. On March 27, 2015, Plaintiff Bazini filed an amended complaint asserting additional claims under Sections 14(a) and 20(a) of the Securities Exchange Act of 1934.

On February 11, 2015, Mark Hinnau, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Hinnau Lawsuit"). The allegations, claims, and relief sought in the Hinnau Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Stephen Weaver, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Weaver

Lawsuit”). The allegations, claims, and relief sought in the Weaver Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Adrian Dieckman, a purported Regency unitholder, filed a class action complaint on behalf of Regency’s common unitholders in the United States District Court for the Northern District of Texas (the “Dieckman Lawsuit”). The allegations, claims, and relief sought in the Dieckman Lawsuit are similar to those in the Blankman Lawsuit, except that the Dieckman Lawsuit does not assert an aiding and abetting claim.

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On February 13, 2015, Irwin Berlin, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Berlin Lawsuit"). The allegations, claims, and relief sought in the Berlin Lawsuit are similar to those in the Blankman Lawsuit.

On March 13, 2015, the Court in the 95th Judicial District Court of Dallas County, Texas transferred and consolidated the Yeager and Coggia Lawsuits into the Engel Lawsuit and captioned the consolidated lawsuit as Engel v. Regency GP, LP, et al. (the "Consolidated State Lawsuit").

On March 30, 2015, Leonard Cooperman, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Cooperman Lawsuit"). The allegations, claims, and relief sought in the Cooperman Lawsuit are similar to those in the Blankman Lawsuit.

On March 31, 2015, the Court in United States District Court for the Northern District of Texas consolidated the Blankman, Bazini, Hinnau, Weaver, Dieckman, and Berlin Lawsuits into a consolidated lawsuit captioned Bazini v. Bradley, et al. (the "Consolidated Federal Lawsuit"). On April 1, 2015, plaintiffs in the Consolidated Federal Lawsuit filed an Emergency Motion to Expedite Discovery. On April 9, 2015, by order of the Court, the parties submitted a joint submission wherein defendants opposed plaintiffs' request to expedite discovery. On April 17, 2015, the Court denied plaintiffs' motion to expedite discovery.

On June 10, 2015, Adrian Dieckman, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the Court of Chancery of the State of Delaware (the "Dieckman DE Lawsuit"). The lawsuit alleges that the transaction did not comply with the Regency partnership agreement because the Conflicts Committee was not properly formed.

Each of these lawsuits is at a preliminary stage. ETP cannot predict the outcome of these or any other lawsuits that might be filed, nor can we predict the amount of time and expense that will be required to resolve these lawsuits. ETP and the other defendants named in the lawsuits intend to defend vigorously against these and any other actions.

MTBE Litigation

Sunoco, Inc., 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 also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of June 30, 2015, Sunoco, Inc. is a defendant in six cases, including cases initiated by the States of New Jersey, Vermont, the Commonwealth of Pennsylvania, two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action, and one case by the City of Breaux Bridge in the USDC Western District of Louisiana. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court. The New Jersey, Puerto Rico, Vermont, and Pennsylvania cases assert natural resource damage claims.

Fact discovery has concluded with respect to an initial set of 19 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. Insufficient information has been developed about the plaintiffs' legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco, Inc. in these matters. It is reasonably possible that a loss may be realized; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. 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 during 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 the Partnership's consolidated financial position.

Enterprise Products Partners, L.P. and Enterprise Products Operating LLC Litigation

On January 27, 2014, a trial commenced between ETP against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETP against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETP. The jury also found that ETP owed Enterprise approximately $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETP and awarded ETP $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETP shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise has filed a notice of appeal. In

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accordance with GAAP, no amounts related to the original verdict or the July 29, 2014 final judgment will be recorded in our financial statements until the appeal process is completed.

Other Litigation and Contingencies

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 June 30, 2015 and December 31, 2014, accruals of approximately $38 million and $37 million, respectively, were reflected on our consolidated 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. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued.

No amounts have been recorded in our June 30, 2015 or December 31, 2014 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

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 Massachusetts Department of Public Utilities (“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 approximately $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 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. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Panhandle (as successor to Southern Union) believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Panhandle 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. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, 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.

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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.
- Currently operating Sunoco, Inc. retail sites.
- Legacy sites related to Sunoco, Inc., that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco, Inc. 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 June 30, 2015, Sunoco, Inc. had been named as a PRP at approximately 52 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.’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. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. 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.

	June 30, 2015	December 31, 2014
Current	$49	$41
Non-current	334	360
Total environmental liabilities	$383	$401

In 2013, we established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

During the three months ended June 30, 2015 and 2014, Sunoco, Inc. recorded $11 million and $9 million, respectively, of expenditures related to environmental cleanup programs. During the six months ended June 30, 2015 and 2014, Sunoco, Inc. recorded $18 million and $17 million, respectively, of expenditures related to environmental cleanup programs.

On June 29, 2011, the U.S. Environmental Protection Agency finalized a rule under the Clean Air Act 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 U.S. Department of Transportation 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.

13. DERIVATIVE 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 our 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 statements of operations.

We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream segment whereby 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

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transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

We may use derivatives in our liquids transportation and services segment to manage our storage facilities and the purchase and sale of purity NGLs.

Sunoco Logistics utilizes derivatives such as swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products, crude and NGLs. These derivative contracts act as a hedging mechanism against the volatility of prices by allowing Sunoco Logistics to transfer this price risk to counterparties who are able and willing to bear it. Sunoco Logistics does not designate any of its derivative contracts as hedges for accounting purposes. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

We also use derivatives to hedge a variety of price risks in our retail marketing segment. Futures and swaps are used to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales and transportation costs. The derivatives used in our retail marketing segment represent economic hedges; however, we have elected not to designate any of these derivative contracts as hedges in this business segment. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

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 and marketing activities related to power and natural gas 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.

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The following table details our outstanding commodity-related derivatives:

	June 30, 2015		December 31, 2014	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	(1,075,000)	2015-2016	(232,500)	2015
Basis Swaps IFERC/NYMEX[1]	(4,527,500)	2015-2016	(13,907,500)	2015-2016
Options – Calls	5,000,000	2015	5,000,000	2015
Power (Megawatt):				
Forwards	373,357	2015-2016	288,775	2015
Futures	436,789	2015-2016	(156,000)	2015
Options – Puts	(581,328)	2015	(72,000)	2015
Options – Calls	(1,428,154)	2015	198,556	2015
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	10,327,500	2015-2016	57,500	2015
Swing Swaps IFERC	23,335,000	2015-2016	46,150,000	2015
Fixed Swaps/Futures	(11,577,500)	2015-2016	(34,304,000)	2015-2016
Forward Physical Contracts	4,424,847	2015	(9,116,777)	2015
Natural Gas Liquid and Crude (Bbls) – Forwards/Swaps	(3,730,800)	2015-2016	(4,417,400)	2015-2016
Refined Products (Bbls) – Futures	(1,195,000)	2015-2016	13,745,755	2015
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(37,555,000)	2016	(39,287,500)	2015
Fixed Swaps/Futures	(37,555,000)	2016	(39,287,500)	2015
Hedged Item – Inventory	37,555,000	2016	39,287,500	2015

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

Regency previously had swap contracts that settled against certain NGLs, condensate and natural gas market prices. In April 2015, in connection with the Regency Merger, Regency settled all outstanding swap contracts and received net proceeds of $56 million.

Interest Rate Risk

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

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

Term	Type(1)	Notional Amount Outstanding	
		June 30, 2015	December 31, 2014
July 2015(2)	Forward-starting to pay a fixed rate of 3.40% and receive a floating rate	$100	$200
July 2016(3)	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	200
July 2017(4)	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	300
July 2018(4)	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
July 2019(4)	Forward-starting to pay a fixed rate of 3.25% and receive a floating rate	200	300
December 2018	Pay a floating rate based on 3-month LIBOR and receive a fixed rate of 1.53%	1,200	—
March 2019	Pay a floating rate based on 3-month LIBOR and receive a fixed rate of 1.42%	300	—
February 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	—	200

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

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

(3) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.

(4) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

Credit Risk

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership’s portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership’s counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, motor fuel distributors, municipalities, gas and electric utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic factors or regulatory changes that impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

We have maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, 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 or about 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.

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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 sheets and recognized in net income or other comprehensive income.

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2015	December 31, 2014	June 30, 2015	December 31, 2014
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$3	$43	$—	$—
	3	43	—	—
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	265	617	(245)	(577)
Commodity derivatives	18	107	(16)	(23)
Interest rate derivatives	1	3	(105)	(155)
Embedded derivatives in ETP Preferred Units	—	—	(12)	(16)
	284	727	(378)	(771)
Total derivatives	$287	$770	$(378)	$(771)

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	
	Balance Sheet Location	June 30, 2015	December 31, 2014	June 30, 2015	December 31, 2014
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	$18	$23	$(16)	$(23)
Broker cleared derivative contracts	Other current assets	264	674	(248)	(574)
		282	697	(264)	(597)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(12)	(19)	12	19
Payments on margin deposit	Other current assets	16	5	(9)	(22)
		4	(14)	3	(3)
Net derivatives with offsetting agreements		286	683	(261)	(600)
Derivatives without offsetting agreements		1	87	(117)	(171)
Total derivatives		$287	$770	$(378)	$(771)

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.

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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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$—	$(2)	$1	$(6)
Total	$—	$(2)	$1	$(6)

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2015	2014	2015	2014
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$—	$(2)	$—	$(6)
Total		$—	$(2)	$—	$(6)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2015	2014	2015	2014
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$11	$—	$8	$(6)
Total		$11	$—	$8	$(6)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2015	2014	2015	2014
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$(6)	$(5)	$(8)	$2
Commodity derivatives – Non-trading	Cost of products sold	(40)	(37)	(48)	(43)
Interest rate derivatives	Gains (losses) on interest rate derivatives	127	(46)	50	(48)
Embedded derivatives	Other expense	2	(9)	4	(10)

Total	$83	$(97)	$(2)	$(99)

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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 on behalf of other subsidiaries of ETE, which includes the reimbursement of various operating and general and administrative expenses incurred by us on behalf of ETE and its subsidiaries.

In connection with the Lake Charles LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015.

The Partnership also has related party transactions with several of its equity method investees. In addition to commercial transactions, these transactions include the provision of certain management services and leases of certain assets.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Affiliated revenues	$130	$361	$206	$689

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

	June 30, 2015	December 31, 2014
Accounts receivable from related companies:		
ETE	$32	$11
PES	27	6
FGT	9	9
Lake Charles LNG	35	3
Other	98	110
Total accounts receivable from related companies:	$201	$139
Accounts payable to related companies:		
PES	$8	$—
FGT	—	2
Lake Charles LNG	2	2
Other	—	21
Total accounts payable to related companies:	$10	$25

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15. OTHER INFORMATION

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

Other Current Assets

Other current assets consisted of the following:

	June 30, 2015	December 31, 2014
Deposits paid to vendors	$36	$65
Deferred income taxes	—	14
Income taxes receivable	151	17
Prepaid expenses and other	174	200
Total other current assets	$361	$296

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	June 30, 2015	December 31, 2014
Interest payable	$397	$382
Customer advances and deposits	100	103
Accrued capital expenditures	608	673
Accrued wages and benefits	156	233
Taxes payable other than income taxes	302	236
Income taxes payable	4	54
Deferred income taxes	99	99
Other	317	319
Total accrued and other current liabilities	$1,983	$2,099

16. REPORTABLE SEGMENTS

Our financial statements currently reflect the following reportable segments, which conduct their business in the United States, as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- liquids 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 liquids transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our investment in Sunoco

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

In connection with the Regency Merger, Regency’s operations were aggregated into ETP’s existing segments. Regency’s gathering and processing operations were aggregated into our midstream segment. Regency’s natural gas transportation operations were aggregated into our intrastate transportation and storage and interstate transportation and storage segments. Regency’s contract services and natural resources operations were aggregated into our all other segment. Additionally, in June 2015 Regency’s 30% equity interest in Lone Star was transferred to ETC OLP.

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 include 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.

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The following tables present financial information by segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$486	$667	$1,027	$1,512
Intersegment revenues	83	45	128	134
	569	712	1,155	1,646
Interstate transportation and storage:				
Revenues from external customers	239	245	510	540
Intersegment revenues	4	4	9	7
	243	249	519	547
Midstream:				
Revenues from external customers	771	1,297	1,524	2,349
Intersegment revenues	473	501	875	908
	1,244	1,798	2,399	3,257
Liquids transportation and services:				
Revenues from external customers	779	867	1,587	1,659
Intersegment revenues	45	36	68	74
	824	903	1,655	1,733
Investment in Sunoco Logistics:				
Revenues from external customers	3,121	4,766	5,647	9,218
Intersegment revenues	82	55	128	80
	3,203	4,821	5,775	9,298
Retail marketing:				
Revenues from external customers	5,557	5,568	10,339	10,576
Intersegment revenues	(20)	—	3	3
	5,537	5,568	10,342	10,579
All other:				
Revenues from external customers	587	678	1,232	1,261
Intersegment revenues	134	147	231	224
	721	825	1,463	1,485
Eliminations	(801)	(788)	(1,442)	(1,430)
Total revenues	$11,540	$14,088	$21,866	$27,115

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$117	$124	$294	$315
Interstate transportation and storage	285	291	586	617
Midstream	376	356	689	592
Liquids transportation and services	151	141	317	269
Investment in Sunoco Logistics	326	280	547	488
Retail marketing	140	136	269	245
All other	93	65	152	205
Total	1,488	1,393	2,854	2,731
Depreciation, depletion and amortization	(501)	(436)	(980)	(796)
Interest expense, net of interest capitalized	(336)	(295)	(646)	(569)
Gain on sale of AmeriGas common units	—	93	—	163
Gains (losses) on interest rate derivatives	127	(46)	50	(48)
Non-cash unit-based compensation expense	(23)	(15)	(43)	(32)
Unrealized losses on commodity risk management activities	(42)	(1)	(119)	(33)
Inventory valuation adjustments	184	20	150	34
Adjusted EBITDA related to discontinued operations	—	—	—	(27)
Adjusted EBITDA related to unconsolidated affiliates	(215)	(190)	(361)	(400)
Equity in earnings of unconsolidated affiliates	117	77	174	181
Other, net	(19)	(24)	(14)	(24)
Income from continuing operations before income tax expense	$780	$576	$1,065	$1,180

	June 30, 2015	December 31, 2014
Assets:		
Intrastate transportation and storage	$4,934	$4,984
Interstate transportation and storage	11,452	10,779
Midstream	16,412	15,562
Liquids transportation and services	6,322	4,568
Investment in Sunoco Logistics	14,683	13,619
Retail marketing	8,092	8,930
All other	5,656	4,232
Total assets	$67,551	$62,674

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17. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

On April 30, 2015, in connection with the Regency Merger, ETP entered into various supplemental indentures pursuant to which ETP has agreed to fully and unconditionally guarantee all payment obligations of Regency for all of its outstanding senior notes.

ELG, Aqua – PVR and ORS do not fully and unconditionally guarantee, on a joint and several basis, the Regency senior notes. Included in the Parent financial statements are the Partnership's intercompany investments in all consolidated subsidiaries. Included in the Issuer financial statements are Regency's intercompany investments in all consolidated subsidiaries and Regency's investments in unconsolidated affiliates. ELG, Aqua – PVR and ORS are included in the non-guarantor subsidiaries, as well as the unconsolidated subsidiaries of ETP.

The consolidating financial information for the Parent, Issuer, Guarantor Subsidiaries, and Non-Guarantor Subsidiaries are as follows:

	June 30, 2015					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$306	$—	$—	$ 1,317	$(8)	$1,615
All other current assets	2,988	—	419	2,902	(665)	5,644
Property, plant, and equipment, net	153	—	9,295	33,630	(221)	42,857
Investments in subsidiaries	36,273	19,545	—	6,664	(62,482)	—
Investments in unconsolidated affiliates	23	—	1,029	2,388	227	3,667
All other assets	3,177	—	4,620	9,599	(3,628)	13,768
Total assets	$42,920	$19,545	$15,363	$ 56,500	$(66,777)	$67,551
Current liabilities	362	—	972	4,492	(665)	5,161
Non-current liabilities	16,156	4,634	67	17,310	(3,628)	34,539
Noncontrolling interest	—	—	—	35	6,503	6,538
Total partners' capital	26,402	14,911	14,324	34,663	(68,987)	21,313
Total liabilities and equity	$42,920	$19,545	$15,363	$ 56,500	$(66,777)	$67,551

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	December 31, 2014					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$17	$—	$—	$ 654	$(8)	$663
All other current assets	273	—	667	4,587	(147)	5,380
Property, plant, and equipment, net	103	—	8,948	30,094	(238)	38,907
Investments in subsidiaries	24,361	19,829	—	6,755	(50,945)	—
Investments in unconsolidated affiliates	63	—	2,252	2,441	(996)	3,760
All other assets	3,826	—	4,765	10,047	(4,674)	13,964
Total assets	$28,643	$19,829	$16,632	$ 54,578	$(57,008)	$62,674
Current liabilities	1,117	—	723	5,073	(229)	6,684
Non-current liabilities	11,561	5,185	1,575	16,952	(4,594)	30,679
Noncontrolling interest	—	—	—	60	5,093	5,153
Predecessor equity	—	14,644	14,334	358	(21,248)	8,088
Total partners’ capital	15,965	—	—	32,135	(36,030)	12,070
Total liabilities and equity	$28,643	$19,829	$16,632	$ 54,578	$(57,008)	$62,674

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	Three Months Ended June 30, 2015					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$—	$887	$ 10,665	$(12)	$11,540
Operating costs, expenses, and other	(12)	1	903	9,771	(11)	10,652
Operating income (loss)	12	(1)	(16)	894	(1)	888
Interest expense, net	(190)	(74)	7	(125)	46	(336)
Equity in earnings (losses) of unconsolidated affiliates	430	32	(6)	281	(620)	117
Gains on interest rate derivatives	127	—	—	—	—	127
Other, net	319	(21)	(12)	(256)	(46)	(16)
Income (loss) before income taxes	698	(64)	(27)	794	(621)	780
Income tax benefit	(8)	(8)	—	(43)	—	(59)
Income (loss) from continuing operations	706	(56)	(27)	837	(621)	839
Income from discontinued operations	—	—	48	—	(48)	—
Net income (loss)	706	(56)	21	837	(669)	839
Less: Net income attributable to noncontrolling interest	—	—	—	220	(8)	212
Less: Net loss attributable to predecessor	—	—	—	(26)	(1)	(27)
Net income (loss) attributable to partners	$706	$(56)	$21	$ 643	$(660)	$654
Other comprehensive income (loss)	$(1)	$—	$—	$ 1	$(1)	$(1)
Comprehensive income (loss)	705	(56)	21	838	(670)	838
Comprehensive income attributable to noncontrolling interest	—	—	—	220	(8)	212
Comprehensive loss attributable to predecessor	—	—	—	(27)	—	(27)
Comprehensive income (loss) attributable to partners	$705	$(56)	$21	$ 645	$(662)	$653

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	Three Months Ended June 30, 2014					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$—	$1,163	$ 12,926	$(1)	$14,088
Operating costs, expenses, and other	(68)	—	1,138	12,253	(3)	13,320
Operating income	68	—	25	673	2	768
Interest expense, net	(172)	65	(6)	(95)	(87)	(295)
Equity in earnings (losses) of unconsolidated affiliates	520	(51)	(3)	293	(682)	77
Gain on sale of AmeriGas common units	93	—	—	—	—	93
Losses on interest rate derivatives	(39)	—	—	(7)	—	(46)
Other, net	39	(7)	—	(3)	(50)	(21)
Income before income taxes	509	7	16	861	(817)	576
Income tax expense (benefit)	(6)	1	—	76	—	71
Income from continuing operations	515	6	16	785	(817)	505
Income from discontinued operations	—	—	51	42	(51)	42
Net income	515	6	67	827	(868)	547
Less: Net income attributable to noncontrolling interest	—	—	3	77	7	87
Less: Net loss attributable to predecessor	—	—	—	(11)	—	(11)
Net income attributable to partners	$515	$6	$64	$ 761	$(875)	$471
Other comprehensive income (loss)	$2	$—	$—	$ (2)	$2	$2
Comprehensive income	517	6	67	825	(866)	549
Comprehensive income attributable to noncontrolling interest	—	—	3	77	7	87
Comprehensive loss attributable to predecessor	—	—	—	(11)	—	(11)
Comprehensive income attributable to partners	$517	$6	$64	$ 759	$(873)	$473

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	Six Months Ended June 30, 2015					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$—	$1,869	$ 20,009	$(12)	$21,866
Operating costs, expenses, and other	(19)	1	1,864	18,537	(13)	20,370
Operating income (loss)	19	(1)	5	1,472	1	1,496
Interest expense, net	(358)	(150)	1	(240)	101	(646)
Equity in earnings of unconsolidated affiliates	741	106	44	279	(996)	174
Gains on interest rate derivatives	50	—	—	—	—	50
Other, net	480	(19)	(11)	(358)	(101)	(9)
Income (loss) before income taxes	932	(64)	39	1,153	(995)	1,065
Income tax benefit	(3)	(3)	—	(36)	—	(42)
Income (loss) from continuing operations	935	(61)	39	1,189	(995)	1,107
Income from discontinued operations	—	—	48	—	(48)	—
Net income (loss)	935	(61)	87	1,189	(1,043)	1,107
Less: Net income attributable to noncontrolling interest	—	—	—	210	(4)	206
Less: Net loss attributable to predecessor	—	—	—	(34)	—	(34)
Net income (loss) attributable to partners	$935	$(61)	$87	$ 1,013	$(1,039)	$935
Other comprehensive income (loss)	$42	$—	$—	$ (42)	$42	$42
Comprehensive income (loss)	977	(61)	87	1,147	(1,001)	1,149
Comprehensive income attributable to noncontrolling interest	—	—	—	210	(4)	206
Comprehensive loss attributable to predecessor	—	—	—	(34)	—	(34)
Comprehensive income (loss) attributable to partners	$977	$(61)	$87	$ 971	$(997)	$977

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	Six Months Ended June 30, 2014					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$—	$2,011	$ 25,105	$(1)	$27,115
Operating costs, expenses, and other	(36)	—	1,972	23,708	(3)	25,641
Operating income	36	—	39	1,397	2	1,474
Interest expense, net	(349)	16	(13)	(181)	(42)	(569)
Equity in earnings of unconsolidated affiliates	985	—	40	320	(1,164)	181
Gain on sale of AmeriGas common units	163	—	—	—	—	163
Losses on interest rate derivatives	(35)	—	—	(13)	—	(48)
Other, net	82	(8)	3	(3)	(95)	(21)
Income before income taxes	882	8	69	1,520	(1,299)	1,180
Income tax expense (benefit)	(6)	1	(2)	223	—	216
Income from continuing operations	888	7	71	1,297	(1,299)	964
Income from discontinued operations	—	—	51	66	(51)	66
Net income	888	7	122	1,363	(1,350)	1,030
Less: Net income attributable to noncontrolling interest	—	—	—	134	7	141
Less: Net income attributable to predecessor	—	—	—	3	—	3
Net income attributable to partners	$888	$7	$122	$ 1,226	$(1,357)	$886
Other comprehensive income (loss)	$(9)	$—	$—	$ 9	$(9)	$(9)
Comprehensive income	879	7	122	1,372	(1,359)	1,021
Comprehensive income attributable to noncontrolling interest	—	—	—	134	7	141
Comprehensive income attributable to predecessor	—	—	—	3	—	3
Comprehensive income attributable to partners	$879	$7	$122	$ 1,235	$(1,366)	$877

	Six Months Ended June 30, 2015					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$(2,719)	$—	$727	$ 4,036	$(911)	$1,133
Cash flows from investing activities	(666)	—	(620)	(3,764)	1,394	(3,656)
Cash flows from financing activities	3,674	—	(107)	391	(483)	3,475
Change in cash	289	—	—	663	—	952

Cash at beginning of period	17	—	—	654	(8)	663
Cash at end of period	$306	$—	$—	$ 1,317	$(8)	$1,615

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	Six Months Ended June 30, 2014					
	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$514	$—	$234	$ 2,299	$(1,255)	$1,792
Cash flows from investing activities	759	—	(653)	(1,791)	57	(1,628)
Cash flows from financing activities	(995)	—	430	(195)	1,198	438
Change in cash	278	—	11	313	—	602
Cash at beginning of period	—	—	—	568	—	568
Cash at end of period	$278	$—	$11	$ 881	$—	$1,170

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

(Tabular dollar and unit amounts, except per unit data, 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 (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; (ii) our Annual Report on Form 10-K for the year ended December 31, 2014 filed with the SEC on March 2, 2015; and (iii) our management's discussion and analysis of financial condition and results of operations included in our 2014 Form 10-K. 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, 2014.

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

OVERVIEW

The primary activities and 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 La Grange Acquisition, L.P., which we refer to as ETC OLP and Regency; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger, CrossCountry and ET Rover Pipeline LLC. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems. Regency owns a 50% interest in MEP.
- Liquids operations, including NGL transportation, storage and fractionation services primarily through Lone Star.
- Product and crude oil operations, including the following:
  - product and crude oil transportation, terminalling services and acquisition and marketing activities through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco, Inc., Susser and Sunoco LP.

RECENT DEVELOPMENTS

Sunoco LP

In April 2015, Sunoco LP acquired a 31.58% equity interest in Sunoco, LLC from Retail Holdings for $816 million. Sunoco, LLC distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest regions of the United States. Sunoco LP paid $775 million in cash and issued $41 million of Sunoco LP common units to Retail Holdings, based on the five-day volume weighted average price of Sunoco LP's common units as of March 20, 2015.

In July 2015, Sunoco LP acquired 100% of Susser from ETP in a transaction valued at $1.93 billion. Sunoco LP paid approximately $967 million in cash and issued 22 million Sunoco LP common units, valued at approximately $967 million, to ETP. In addition, there will be an exchange for 11 million Sunoco LP units owned by Susser for another 11 million new Sunoco LP units to a subsidiary of ETP.

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In July 2015, ETE entered into an exchange and repurchase agreement with ETP, pursuant to which ETE would acquire 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, in exchange for the repurchase of 21 million ETP common units owned by ETE. In connection with ETP's 2014 acquisition of Susser, ETE agreed to provide ETP a $35 million annual IDR subsidy for 10 years, which would terminate upon the closing of ETE's acquisition of Sunoco GP. In connection with the exchange and repurchase, ETE agreed to provide ETP a $35 million annual IDR subsidy for two years. Following this transaction, Sunoco LP will no longer be consolidated for accounting purposes by ETP. This transaction is expected to close in August 2015.

Regency Merger

On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency, with Regency continuing as the surviving entity (the "Regency Merger"). Each Regency common unit and Class F unit was converted into the right to receive 0.4124 Partnership common units. ETP issued 172.2 million Partnership common units to Regency unitholders, including 15.5 million units issued to Partnership subsidiaries. The 1.9 million outstanding Regency series A preferred units were converted into corresponding new Partnership Series A Preferred Units on a one-for-one basis.

In connection with the Regency Merger, ETE will reduce the incentive distributions it receives from the Partnership by a total of $320 million over a five-year period. The IDR subsidy will be $80 million in the first year post-closing and $60 million per year for the following four years.

The Regency Merger was a combination of entities under common control; therefore Regency's assets and liabilities were not adjusted. The Partnership's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner). Predecessor equity included on the consolidated financial statements represents Regency's equity prior to the Regency Merger.

Quarterly Cash Distribution Increase

In July 2015, ETP announced an increase in its quarterly distribution to $1.035 per Partnership common unit ($4.14 annualized) for the quarter ended June 30, 2015, representing an increase of $0.32 per Partnership common unit on an annualized basis, or 8.4%, compared to the second quarter of 2014.

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Results of Operations

Consolidated Results

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Change	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$117	$124	$(7)	$294	$315	$(21)
Interstate transportation and storage	285	291	(6)	586	617	(31)
Midstream	376	356	20	689	592	97
Liquids transportation and services	151	141	10	317	269	48
Investment in Sunoco Logistics	326	280	46	547	488	59
Retail marketing	140	136	4	269	245	24
All other	93	65	28	152	205	(53)
Total	1,488	1,393	95	2,854	2,731	123
Depreciation, depletion and amortization	(501)	(436)	(65)	(980)	(796)	(184)
Interest expense, net of interest capitalized	(336)	(295)	(41)	(646)	(569)	(77)
Gain on sale of AmeriGas common units	—	93	(93)	—	163	(163)
Gains (losses) on interest rate derivatives	127	(46)	173	50	(48)	98
Non-cash unit-based compensation expense	(23)	(15)	(8)	(43)	(32)	(11)
Unrealized losses on commodity risk management activities	(42)	(1)	(41)	(119)	(33)	(86)
Inventory valuation adjustments	184	20	164	150	34	116
Adjusted EBITDA related to discontinued operations	—	—	—	—	(27)	27
Adjusted EBITDA related to unconsolidated affiliates	(215)	(190)	(25)	(361)	(400)	39
Equity in earnings of unconsolidated affiliates	117	77	40	174	181	(7)
Other, net	(19)	(24)	5	(14)	(24)	10
Income from continuing operations before income tax expense	780	576	204	1,065	1,180	(115)
Income tax (expense) benefit from continuing operations	59	(71)	130	42	(216)	258
Income from continuing operations	839	505	334	1,107	964	143
Income from discontinued operations	—	42	(42)	—	66	(66)
Net income	$839	$547	$292	$1,107	$1,030	$77

See the detailed discussion of Segment Adjusted EBITDA and Segment Operating Results.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

Gain on Sale of AmeriGas Common Units. In January 2014 and June 2014, the Partnership recognized a gain on the sale of 9.2 million and 8.5 million AmeriGas common units, respectively, that were originally received in connection with the contribution of our propane business to AmeriGas in 2012. As of June 30, 2015, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

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Gains (Losses) on Interest Rate Derivatives. Gains on interest rate derivatives during the three and six months ended June 30, 2015 resulted from increases in forward interest rates, which caused our forward-starting swaps to increase in value. Conversely, decreases in forward interest rates resulted in losses on interest rate derivatives during the three and six months ended June 30, 2014.

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

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco Logistics and our retail marketing operations as a result of commodity price changes between periods.

Adjusted EBITDA Related to Discontinued Operations. Amounts for the six months ended June 30, 2014 reflect the results of a marketing business that was sold effective April 1, 2014.

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

Income Tax Expense (Benefit) from Continuing Operations. For the three and six months ended June 30, 2015, the Partnership’s income tax expense from continuing operations decreased primarily due to a decrease in earnings among the Partnership’s consolidated corporate subsidiaries, which resulted in decreases in income tax expense of $75 million and $135 million, respectively. The Partnership’s income tax expense also decreased for the three and six months ended June 30, 2015 by $12 million due to the exclusion of a portion of the dividend income received by certain of our consolidated corporate subsidiaries. For the three and six months ended June 30, 2015, the Partnership’s income tax expense was favorably impacted by $11 million due to a reduction in the statutory Texas franchise tax rate which was enacted by the Texas legislature during the second quarter of 2015. In addition, for the six months ended June 30, 2015, the Partnership’s income tax expense from continuing operations also decreased due to unfavorable income tax adjustments of $87 million in the prior period related to the Lake Charles LNG Transaction, which occurred in the first quarter of 2014 and was treated as a sale for tax purposes.

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$29	$26	$3	$48	$44	$4
FEP	13	13	—	27	27	—
PES	47	18	29	38	35	3
MEP	11	11	—	23	22	1
HPC	6	8	(2)	15	15	—
AmeriGas	(2)	(8)	6	4	26	(22)
Other	13	9	4	19	12	7
Total equity in earnings of unconsolidated affiliates	$117	$77	$40	$174	$181	$(7)
Adjusted EBITDA related to unconsolidated affiliates[(1)]:						
Citrus	$85	$81	$4	$154	$149	$5
FEP	18	18	—	37	37	—
PES	54	25	29	56	48	8
MEP	24	26	(2)	48	52	(4)
HPC	15	14	1	30	28	2
AmeriGas	—	5	(5)	—	56	(56)
Other	19	21	(2)	36	30	6
Total Adjusted EBITDA related to unconsolidated affiliates	$215	$190	$25	$361	$400	$(39)
Distributions received from unconsolidated affiliates:						
Citrus	$47	$41	$6	$80	$75	$5
FEP	16	16	—	32	32	—
PES	19	—	19	21	—	21
MEP	20	18	2	40	36	4
HPC	14	11	3	27	21	6
AmeriGas	—	11	(11)	—	22	(22)
Other	9	11	(2)	20	16	4
Total distributions received from unconsolidated affiliates	$125	$108	$17	$220	$202	$18

(1) These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates and are based on our equity in earnings or losses of our unconsolidated affiliates adjusted for our proportionate share of the unconsolidated affiliates' interest, depreciation, amortization, non-cash items and taxes.

Segment Operating Results

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.

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The tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

- Gross margin, operating expenses, and selling, general and administrative expenses. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.
- Unrealized gains or losses on commodity risk management activities and inventory valuation adjustments. 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 expenses. 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.

Intrastate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Natural gas transported (MMBtu/d)	8,666,363	9,069,215	(402,852)	8,739,721	9,299,177	(559,456)
Revenues	$569	$712	$(143)	$1,155	$1,646	$(491)
Cost of products sold	383	551	(168)	799	1,285	(486)
Gross margin	186	161	25	356	361	(5)
Unrealized (gains) losses on commodity risk management activities	(34)	(3)	(31)	1	24	(23)
Operating expenses, excluding non-cash compensation expense	(42)	(43)	1	(78)	(85)	7
Selling, general and administrative expenses, excluding non-cash compensation expense	(8)	(5)	(3)	(15)	(12)	(3)
Adjusted EBITDA related to unconsolidated affiliates	15	14	1	30	27	3
Segment Adjusted EBITDA	$117	$124	$(7)	$294	$315	$(21)

Volumes. For the three and six months ended June 30, 2015 compared to the same periods last year, transported volumes decreased primarily due to lower production from certain key shippers in the Barnett Shale region, offset by the ramp up of volumes related to significant new long-term transportation contracts.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Transportation fees	$127	$114	$13	$255	$231	$24
Natural gas sales and other	27	17	10	51	58	(7)
Retained fuel revenues	15	26	(11)	30	56	(26)
Storage margin, including fees	17	4	13	20	16	4
Total gross margin	$186	$161	$25	$356	$361	$(5)

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Intrastate transportation and storage gross margin increased for the three months ended June 30, 2015 and decreased for the six months ended June 30, 2015 compared to the same periods last year due to the net impact of the following:

- Transportation fees. Transportation fees increased, despite a reduction in volume, primarily due to increased revenue from renegotiated and newly initiated long-term fixed capacity fee contracts on our Houston pipeline system.
- Natural gas sales and other. For the three months ended June 30, 2015 compared to the same period last year, margin increased $10 million primarily due to an increase in margin from the purchase and sale of natural gas on our system. For the six months ended June 30, 2015 compared to the same period last year, margin decreased $7 million primarily due to a decrease in gains from the buying and selling of physical gas on our system. Gains were higher in the prior year due to opportunities from the commodity price volatility created by the cold winter season during the first quarter of 2014.
- Retained fuel revenues. For the three and six months ended June 30, 2015 compared to the same periods last year, retention revenue decreased $11 million and $26 million, respectively, primarily due to significantly lower market prices. The spot price at the Houston Ship Channel location for the three and six months ended June 30, 2015 averaged $2.69/MMBtu and $2.69/MMBtu, respectively, representing decreases of $1.86/MMBtu and $1.05/MMBtu, respectively, compared to the same periods last year.

Storage margin was comprised of the following:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Withdrawals from storage natural gas inventory (MMBtu)	—	—	—	15,782,500	37,806,832	(22,024,332)
Realized margin on natural gas inventory transactions	$(23)	$(6)	$(17)	$12	$28	$(16)
Fair value inventory adjustments	11	—	11	23	(11)	34
Unrealized gains (losses) on derivatives	22	4	18	(29)	(14)	(15)
Margin recognized on natural gas inventory, including related derivatives	10	(2)	12	6	3	3
Revenues from fee-based storage	7	6	1	14	13	1
Total storage margin	$17	$4	$13	$20	$16	$4

For the three and six months ended June 30, 2015 compared to the same periods last year, the increase in storage margin was primarily due to an increase in the volume of natural gas we own in the Bammel storage facility. Gains are realized as a result of the spread between the spot price of our natural gas widening in relation to the market value of the forward contracts used to hedge that natural gas. Due to the unfavorable market environment, we did not withdraw 100% of our gas in storage during the 2015 winter season. As a result, we realized losses from the settlement of financial derivative contracts during the three months ended June 30, 2015, without an offsetting realized gain from the withdrawal and sale of physical gas.

Unrealized (Gains) Losses on Commodity Risk Management Activities. For the three months ended June 30, 2015 compared to the same period last year, we experienced an increase of $31 million in the margin from unrealized gains and losses on commodity risk management activities. For the three months ended June 30, 2015, unrealized gains and losses from commodity risk management activities of $34 million consisted of unrealized gains of $22 million from storage and non-storage related derivatives, as well as a favorable fair value adjustment of $11 million to hedged storage gas inventory. Unrealized gains from storage related activities were partially offset by realized losses on the settlement of storage related derivatives as illustrated in the storage margin table above. For the three months ended June 30, 2014, the unrealized gains from commodity risk management activities of $3 million consisted of gains from the mark-to-market of storage related derivative contracts.

For the six months ended June 30, 2015 compared to the same period last year, we experienced a decrease in unrealized losses of $23 million. For the six months ended June 30, 2015, unrealized losses from storage and non-storage related derivatives were primarily offset by unrealized gains for the mark-to-market of physical gas inventory held in storage. For the six months ended June 30, 2014, unrealized losses of $24 million included $14 million of losses from storage and non-storage related derivative contracts, as well as $11 million in losses from the mark-to-market of physical storage gas. Unrealized losses were offset by realized gains from the withdrawal and sale of storage gas during the period.

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Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to a decrease in fuel consumption expense of approximately $2 million and $8 million, respectively, driven by a decrease in fuel market prices.

Interstate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Natural gas transported (MMBtu/d)	5,873,424	5,745,746	127,678	6,331,536	6,365,895	(34,359)
Natural gas sold (MMBtu/d)	14,827	15,733	(906)	15,736	15,758	(22)
Revenues	$243	$249	$(6)	$519	$547	$(28)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(71)	(67)	(4)	(143)	(138)	(5)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(14)	(16)	2	(29)	(30)	1
Adjusted EBITDA related to unconsolidated affiliates	127	125	2	239	238	1
Segment Adjusted EBITDA	$285	$291	$(6)	$586	$617	$(31)

Volumes. For the three months ended June 30, 2015 compared to the same period last year, transported volumes increased 183,446 MMBtu/d on the Tiger pipeline, primarily due to slightly higher production in the Haynesville Shale and increased deliveries to pipelines supporting the upper Midwest due to favorable market conditions and 115,648 MMBtu/d on the Transwestern pipeline due to increased customer demand. These increases were partially offset by a decrease of 96,255 MMBtu/d on the Trunkline Gas pipeline as a result of lower customer demand due to lower price spreads.

For the six months ended June 30, 2015 compared to the same period last year, the overall increase in transported volumes during the second quarter, as discussed above, was offset by decreases that occurred in the first quarter. During the first quarter, warmer weather along the Panhandle pipeline and declines in supply into the Sea Robin pipeline from a customer maintenance related outage resulted in decreases of 137,508 MMBtu/d and 78,260 MMBtu/d, respectively, during the first quarter.

Revenues. Interstate transportation and storage revenues decreased for the three months ended June 30, 2015 compared to the same period last year primarily due to the expiration of a transportation rate schedule on the Transwestern pipeline. For the six months ended June 30, 2015 compared to the same period last year, the decrease in revenues also reflected lower transportation loan-related revenues of approximately $22 million as a result of higher basis differentials in 2014 driven by the colder weather.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage operating expenses increased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to an increase in employee-related costs of $2 million and $4 million, respectively, along with the timing of maintenance projects. In addition, interstate transportation and storage operating expenses increased for the six months ended June 30, 2015 compared to the same period last year due to an increase in fuel consumption of $2 million.

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Midstream

	Three Months Ended June 30, 2015	2014	Change	Six Months Ended June 30, 2015	2014	Change
Gathered volumes (MMBtu/d)	10,161,338	8,042,365	2,118,973	9,893,318	6,784,749	3,108,569
NGLs produced (Bbls/d)	399,662	292,880	106,782	383,281	263,613	119,668
Equity NGLs (Bbls/d)	30,160	26,761	3,399	29,130	24,491	4,639
Revenues	$1,244	$1,798	$(554)	$2,399	$3,257	$(858)
Cost of products sold	797	1,339	(542)	1,510	2,472	(962)
Gross margin	447	459	(12)	889	785	104
Unrealized losses on commodity risk management activities	71	—	71	82	3	79
Operating expenses, excluding non-cash compensation expense	(147)	(101)	(46)	(285)	(189)	(96)
Selling, general and administrative expenses, excluding non-cash compensation expense	(3)	(6)	3	(6)	(13)	7
Adjusted EBITDA related to unconsolidated affiliates	7	4	3	8	6	2
Other	1	—	1	1	—	1
Segment Adjusted EBITDA	$376	$356	$20	$689	$592	$97

Volumes. Gathered volumes, NGLs produced and equity NGLs produced increased during the three and six months ended June 30, 2015 compared to the same periods last year primarily due to the Eagle Rock and King Ranch acquisitions, as well as increased gathering and processing capacities in the Eagle Ford Shale, Permian Basin and Cotton Valley regions.

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

	Three Months Ended June 30, 2015	2014	Change	Six Months Ended June 30, 2015	2014	Change
Gathering and processing fee-based revenues	$384	$311	$73	$754	$544	$210
Non fee-based contracts and processing	63	148	(85)	135	241	(106)
Total gross margin	$447	$459	$(12)	$889	$785	$104

Midstream gross margin decreased for the three months ended June 30, 2015 compared to the same period last year due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased production and increased capacity from assets recently placed in service in the Eagle Ford Shale, Permian Basin and Cotton Valley resulted in an increase in fee-based revenues of $48 million. In addition, fee-based margin also increased $5 million primarily due to a change in contract terms on our Southeast Texas system where certain contracts were converted from non fee-based terms to fee-based. The acquisition of Eagle Rock midstream assets in July 2014 also increased fee-based margin by $21 million.
- Non fee-based contracts and processing. Lower commodity prices and changes in contract terms resulted in decreases of $70 million and $9 million, respectively. These decreases were partially offset by an increase from the acquisition of Eagle Rock midstream assets of $11 million.

Midstream gross margin increased for the six months ended June 30, 2015 compared to the same period last year due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased production and increased capacity from assets recently placed in service in the Marcellus Shale, Eagle Ford Shale, Permian Basin and Cotton Valley resulted in an increase in fee-based revenues of $81 million. Fee-based margin also increased $11 million primarily due to a change in contract terms on our Southeast

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Texas system where certain contracts were converted from non fee-based terms to fee-based. The acquisition of Eagle Rock and PVR midstream assets resulted in an increase of $39 million and $79 million, respectively, in fee-based margin.

- Non fee-based contracts and processing. Lower commodity prices and changes in contract terms resulted in a decrease of $105 million and $16 million, respectively. These decreases were partially offset by increases from the acquisition of Eagle Rock midstream assets of $19 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to additional expense from assets recently placed in service and the acquisition of Eagle Rock midstream assets in July 2014.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to a reduction in employee-related costs.

Liquids Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Liquids transportation volumes (Bbls/d)	482,351	367,564	114,787	460,489	337,456	123,033
NGL fractionation volumes (Bbls/d)	253,987	191,255	62,732	240,092	174,171	65,921
Revenues	$824	$903	$(79)	$1,655	$1,733	$(78)
Cost of products sold	628	731	(103)	1,265	1,402	(137)
Gross margin	196	172	24	390	331	59
Unrealized (gains) losses on commodity risk management activities	(5)	—	(5)	4	1	3
Operating expenses, excluding non-cash compensation expense	(39)	(29)	(10)	(74)	(57)	(17)
Selling, general and administrative expenses, excluding non-cash compensation expense	(4)	(4)	—	(8)	(9)	1
Adjusted EBITDA related to unconsolidated affiliates	3	2	1	5	3	2
Segment Adjusted EBITDA	$151	$141	$10	$317	$269	$48

Volumes. For the three and six months ended June 30, 2015 compared to the same periods last year, NGL transportation volumes increased due to an increase in volumes transported on our Lone Star Gateway pipeline system of 67,000 Bbls/d and 50,000 Bbls/d, respectively. These increased volumes were primarily out of west Texas as producers ramped up volumes. Additionally, we commissioned a crude transportation pipeline at the end of 2014 that transported 36,000 Bbls/d and 37,000 Bbls/d for the three and six months ended June 30, 2015, respectively. The remainder of the increase related to volumes on our NGL pipelines from our plants in southeast Texas and in the Eagle Ford region.

Average daily fractionated volumes increased for the three and six months ended June 30, 2015 compared to the same periods last year due to the ramp-up of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas, which was commissioned in October 2013. These volumes include all physical and contractual volumes where we collected a fractionation fee.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Transportation margin	$91	$69	$22	$172	$128	$44
Processing and fractionation margin	76	57	19	141	106	35
Storage margin	39	37	2	83	77	6
Other margin	(10)	9	(19)	(6)	20	(26)
Total gross margin	$196	$172	$24	$390	$331	$59

Liquids transportation and services gross margin increased for the three and six months ended June 30, 2015 compared to the same periods last year due to the following:

- Transportation margin. For the three and six months ended June 30, 2015, transportation margin increased $16 million and $27 million, respectively, due to higher volumes transported out of west Texas on our Lone Star Gateway pipeline system, as noted in the volume discussion above. In addition, the increase in transportation margin for the three and six months ended June 30, 2015 also reflected an increase in volumes transported from our processing plants in southeast Texas and in the Eagle Ford region on our NGL pipeline system to Mont Belvieu, Texas, which increased $3 million and $12 million, respectively. The commissioning of our crude transportation pipeline in south Texas also contributed an additional $3 million and $5 million for the three and six months ended June 30, 2015, respectively.
- Processing and fractionation margin. For the three and six months ended June 30, 2015, processing and fractionation margin increased $18 million and $19 million, respectively, due to the ramp-up of Lone Star's second 100,000 Bbls/d fractionator at Mont Belvieu, Texas, which was commissioned in October 2013. Additionally, the commissioning of the Mariner South LPG export project during February 2015 contributed an additional $12 million and $19 million for the three and six months ended June 30, 2015, respectively.
- Storage margin. Fee-based storage margin increased approximately $7 million and $15 million for the three and six months ended June 30, 2015, respectively, due to increased demand for leased storage capacity as a result of favorable market conditions and a specific contract negotiated in connection with the Mariner South LPG export project. These increases in fee-based storage margin were offset by decreases of $4 million and $8 million for the three and six months ended June 30, 2015, respectively, from lower non fee-based storage activities, including blending activities of $1 million and $3 million, respectively, and $3 million and $5 million, respectively, of lower financial gains recognized on the withdrawal of inventory from our storage facilities.
- Other margin. For the three and six months ended June 30, 2015, other margin decreased primarily due to the accounting treatment of NGL storage inventory and the timing of declines in the market price of component NGL products, resulting in losses realized.

Operating Expenses, Excluding Non-Cash Compensation Expense. Liquids transportation and services operating expenses increased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to the commissioning of the Mariner South LPG export project during February 2015 and the ramp-up of Lone Star's second fractionator at Mont Belvieu, Texas, which was commissioned in October 2013.

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Investment in Sunoco Logistics

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Revenues	$3,203	$4,821	$(1,618)	$5,775	$9,298	$(3,523)
Cost of products sold	2,721	4,517	(1,796)	5,071	8,727	(3,656)
Gross margin	482	304	178	704	571	133
Unrealized losses on commodity risk management activities	7	8	(1)	22	7	15
Operating expenses, excluding non-cash compensation expense	(53)	(26)	(27)	(101)	(65)	(36)
Selling, general and administrative expenses, excluding non-cash compensation expense	(23)	(20)	(3)	(45)	(47)	2
Inventory valuation adjustments	(100)	—	(100)	(59)	—	(59)
Adjusted EBITDA related to unconsolidated affiliates	13	14	(1)	26	22	4
Segment Adjusted EBITDA	$326	$280	$46	$547	$488	$59

Segment Adjusted EBITDA. For the three months ended June 30, 2015 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- an increase of $43 million from terminal facilities, primarily attributable to higher results from Sunoco Logistics' products acquisition and marketing activities of $22 million, which were positively impacted by inventory accounting resulting from the liquidation of certain inventories that were stored during the first quarter to capture the contango market structure. Improved operating results from Sunoco Logistics' Marcus Hook and Nederland terminals of $24 million also contributed to the increase. These positive impacts were partially offset by lower results from Sunoco Logistics' refined products terminals of $3 million; and
- an increase of $30 million from products pipelines, primarily due to higher throughput volumes and higher average pipeline revenue per barrel associated with Sunoco Logistics' Mariner NGL pipeline projects of $33 million. These positive impacts were partially offset by lower contributions from Sunoco Logistics' joint venture interests of $2 million; partially offset by
- a decrease of $15 million from crude oil pipelines, primarily due to lower average pipeline revenue per barrel of $6 million primarily driven by reduced volumes on higher-priced tariff movements. Increased operating expenses of $8 million, which included lower pipeline operating gains and higher line testing costs, and selling, general and administrative expenses of $2 million on growth also contributed to the decrease. These impacts were partially offset by additional throughput volumes of $3 million largely attributable to expansion projects placed into service in 2014; and
- a decrease of $12 million from crude oil acquisition and marketing activities, primarily attributable to lower realized crude oil margins of $19 million, which were negatively impacted by narrowing crude oil differentials compared to the prior year period. This impact was partially offset by increased crude oil volumes of $5 million resulting from 2014 acquisitions and the expansion of Sunoco Logistics' crude oil trucking fleet.

For the six months ended June 30, 2015 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- an increase of $56 million from products pipelines primarily due to higher throughput volumes and higher average pipeline revenue per barrel associated with Sunoco Logistics' Mariner NGL pipeline projects of $52 million and improved contributions from Sunoco Logistics' joint venture interests of $4 million;
- an increase of $7 million from crude oil acquisition and marketing activities, primarily attributable to higher crude oil volumes of $6 million resulting from 2014 acquisitions and the expansion of Sunoco Logistics' crude oil trucking fleet; and

- an increase of $9 million from terminal facilities, primarily attributable to improved operating results from Sunoco Logistics' Marcus Hook and Nederland terminals of $29 million, which was largely offset by lower results from Sunoco Logistics' products acquisition and marketing activities of $23 million; partially offset by
- a decrease of $13 million from crude oil pipelines, largely due to lower average pipeline revenue per barrel of $8 million primarily driven by reduced volumes on higher-priced tariff movements. Increased operating expenses of $10 million, which

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included lower pipeline operating gains and higher line testing costs, and selling, general and administrative expenses of $3 million on growth also contributed to the decrease. These impacts were partially offset by additional throughput volumes of $8 million largely attributable to expansion projects placed into service in 2014.

Retail Marketing

	Three Months Ended June 30, 2015	2014	Change	Six Months Ended June 30, 2015	2014	Change
Motor fuel outlets and convenience stores, end of period:						
Retail	1,276	568	708	1,276	568	708
Third-party wholesale	5,481	4,584	897	5,481	4,584	897
Total	6,757	5,152	1,605	6,757	5,152	1,605
Total motor fuel gallons sold (in millions):						
Retail	639	328	311	1,228	607	621
Third-party wholesale	1,285	1,129	156	2,582	2,241	341
Total	1,924	1,457	467	3,810	2,848	962
Motor fuel gross profit (cents/gallon):						
Retail	21.0	28.5	(7.5)	23.4	25.5	(2.1)
Third-party wholesale	8.1	10.1	(2.0)	7.0	7.6	(0.6)
Volume-weighted average for all gallons	12.4	14.3	(1.9)	12.3	11.4	0.9
Merchandise sales (in millions)	$559	$175	$384	$1,040	$315	$725
Retail merchandise margin %	31.5%	26.6%	4.9%	31.2%	26.2%	5.0%
Revenues	$5,537	$5,568	$(31)	$10,342	$10,579	$(237)
Cost of products sold	5,003	5,260	(257)	9,370	10,016	(646)
Gross margin	534	308	226	972	563	409
Unrealized (gains) losses on commodity risk management activities	1	(1)	2	3	2	1
Operating expenses, excluding non-cash compensation expense	(281)	(135)	(146)	(552)	(261)	(291)
Selling, general and administrative expenses, excluding non-cash compensation expense	(57)	(17)	(40)	(91)	(27)	(64)
Inventory valuation adjustments	(57)	(20)	(37)	(64)	(34)	(30)
Adjusted EBITDA related to unconsolidated affiliates	—	1	(1)	1	2	(1)
Segment Adjusted EBITDA	$140	$136	$4	$269	$245	$24

Gross Margin. For the three months ended June 30, 2015 compared to the same period last year, retail marketing gross margin included the favorable impact of recent acquisitions, including $199 million from the acquisition of Susser in August 2014 and $26 million from other acquisitions. Gross margin also reflected increases in other retail margins of $6 million and non-retail margins of $36 million, and $37 million related to non-cash inventory valuation adjustments. These increases were partially offset by unfavorable fuel margins of $77 million and volumes of $3 million.

For the six months ended June 30, 2015 compared to the same period last year, retail marketing gross margin included the favorable impact of recent acquisitions, including $384 million from the acquisition of Susser in August 2014 and $60 million from other acquisitions. Gross margin also reflected increases in other retail margins of $11 million and $30 million related to non-cash inventory valuation adjustments. These increases were partially offset by unfavorable fuel margins of $44 million, volumes of $4 million and non-retail margins of $29 million.

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Operating Expenses, Excluding Non-Cash Compensation Expense. Retail marketing operating expenses increased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to recent acquisitions.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Retail marketing selling, general and administrative expenses increased for the three and six months ended June 30, 2015 compared to the same periods last year primarily due to recent acquisitions.

Inventory Valuation Adjustments. Retail marketing recorded inventory valuation reserve adjustments as a result of commodity price changes between periods.

All Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Change	2015	2014	Change
Revenues	$721	$825	$(104)	$1,463	$1,485	$(22)
Cost of products sold	617	735	(118)	1,252	1,309	(57)
Gross margin	104	90	14	211	176	35
Unrealized (gains) losses on commodity risk management activities	2	(3)	5	7	(4)	11
Operating expenses, excluding non-cash compensation expense	(22)	(20)	(2)	(43)	(47)	4
Selling, general and administrative expenses, excluding non-cash compensation expense	(47)	(48)	1	(93)	(84)	(9)
Adjusted EBITDA related to discontinued operations	—	—	—	—	27	(27)
Adjusted EBITDA related to unconsolidated affiliates	53	31	22	56	106	(50)
Other	19	19	—	38	38	—
Eliminations	(16)	(4)	(12)	(24)	(7)	(17)
Segment Adjusted EBITDA	$93	$65	$28	$152	$205	$(53)

Amounts reflected in our all other segment primarily include:

- our natural gas marketing and compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture;
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities; and
- our investment in AmeriGas until August 2014.

For the three months ended June 30, 2015 compared to the same period last year, Segment Adjusted EBITDA increased primarily due to an increase of $22 million in Adjusted EBITDA related to unconsolidated affiliates. The increase in Adjusted EBITDA related to unconsolidated affiliates was primarily due to higher earnings driven by stronger refining crack spreads from our investment in PES of $29 million, partially offset by a decrease of $5 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2014.

For the six months ended June 30, 2015 compared to the same period last year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $50 million in Adjusted EBITDA related to unconsolidated affiliates, primarily due to a decrease of $56 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2014; and
- Adjusted EBITDA related to discontinued operations of $27 million in the prior period related to a marketing business that was sold effective April 1, 2014, partially offset by

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- an increase of $19 million related to our natural resources operations, for which the prior period reflected only a partial period due to our acquisition of those operations on March 21, 2014, and an increase of $22 million related to our contract services segment primarily due to an increase in revenue-generating horsepower.

In connection with the Lake Charles LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. These fees were reflected in "Other" in the "All other" segment and for the three and six months ended June 30, 2015 were reflected as an offset to operating expenses of $7 million and $13 million, respectively, and selling, general and administrative expenses of $12 million and $25 million, respectively, in the consolidated statements of operations.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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 capital expenditures (net of contributions in aid of construction costs) for the full year 2015 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Direct[1]:				
Intrastate transportation and storage	$130	$180	$30	$35
Interstate transportation and storage[2]	700	750	130	140
Midstream	1,900	2,000	90	110
Liquids transportation and services:				
NGL	1,550	1,600	20	25
Crude[2]	800	850	—	—
Retail marketing[3]	160	210	55	75
All other (including eliminations)	200	250	35	45
Total direct capital expenditures	5,440	5,840	360	430
Indirect[1]:				
Investment in Sunoco Logistics	2,400	2,600	65	75
Investment in Sunoco LP[3]	220	270	40	50
Total indirect capital expenditures	2,620	2,870	105	125
Total projected capital expenditures	$8,060	$8,710	$465	$555

(1) Indirect capital expenditures comprise those funded by our publicly traded subsidiaries; all other capital expenditures are reflected as direct capital expenditures.

(2) Includes capital expenditures related to our proportionate ownership of the Bakken and Rover pipeline projects.

(3) The retail marketing segment includes the investment in Sunoco LP, as well as ETP's wholly-owned retail marketing operations. Capital expenditures by Sunoco LP are reflected as indirect because Sunoco LP is a publicly traded subsidiary.

The assets used in our natural gas and liquids 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, delays from steel mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors in our anticipated growth capital expenditures for each year.

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We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional common units, dropdown proceeds or the monetization of non-core assets or a combination thereof.

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 resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of inventories, and the timing of advances and deposits received from customers.

Six months ended June 30, 2015 compared to six months ended June 30, 2014. Cash provided by operating activities during 2015 was $1.13 billion compared to $1.79 billion for 2014 and net income was $1.11 billion and $1.03 billion for 2015 and 2014, respectively. The difference between net income and cash provided by operating activities for the six months ended June 30, 2015 primarily consisted of net changes in operating assets and liabilities of $938 million and non-cash items totaling $777 million.

The non-cash activity in 2015 and 2014 consisted primarily of depreciation, depletion and amortization of $980 million and $796 million, respectively, non-cash compensation expense of $43 million and $32 million, respectively, and equity in earnings of unconsolidated affiliates of $174 million and $181 million, respectively. Non-cash activity in 2015 also included deferred income taxes of $79 million and inventory valuation adjustments of $150 million.

Cash paid for interest, net of interest capitalized, was $709 million and $605 million for the six months ended June 30, 2015 and 2014, respectively.

Capitalized interest was $69 million and $37 million for the six months ended June 30, 2015 and 2014, 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 sales or contributions of assets or businesses. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Six months ended June 30, 2015 compared to six months ended June 30, 2014. Cash used in investing activities during 2015 was $3.66 billion compared to $1.63 billion for 2014. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2015 were $4.13 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2014 of $2.08 billion. Additional detail related to our capital expenditures is provided in the table below. During 2015, we received $980 million in cash related to the Bakken Pipeline Transaction and paid $475 million in cash for all other acquisitions. Additionally, during 2014, we received proceeds of $759 million from sales of AmeriGas common units.

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The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the six months ended June 30, 2015:

	Capital Expenditures Recorded During Period			(Increase) Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
Direct[1]:					
Intrastate transportation and storage	$28	$8	$36	$10	$46
Interstate transportation and storage[2]	586	47	633	(189)	444
Midstream	1,014	32	1,046	21	1,067
Liquids transportation and services[2]	1,117	8	1,125	(53)	1,072
Retail marketing[3]	134	33	167	18	185
All other (including eliminations)	183	18	201	(38)	163
Total direct capital expenditures	3,062	146	3,208	(231)	2,977
Indirect[1]:					
Investment in Sunoco Logistics	898	31	929	135	1,064
Investment in Sunoco LP[3]	83	7	90	—	90
Total indirect capital expenditures	981	38	1,019	135	1,154
Total capital expenditures	$4,043	$184	$4,227	$(96)	$4,131

(1) Indirect capital expenditures comprise those funded by our publicly traded subsidiaries; all other capital expenditures are reflected as direct capital expenditures.

(2) Includes capital expenditures related to our proportionate ownership of the Bakken and Rover pipeline projects.

(3) The retail marketing segment includes the investment in Sunoco LP, as well as ETP's wholly-owned retail marketing operations. Capital expenditures by Sunoco LP are reflected as indirect because Sunoco LP is a publicly traded subsidiary.

Financing Activities

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

Six months ended June 30, 2015 compared to six months ended June 30, 2014. Cash provided by financing activities during 2015 was $3.48 billion compared to $438 million for 2014. In 2015 and 2014, we received net proceeds from Common Unit offerings of $724 million and $484 million, respectively. In 2015 and 2014, our subsidiaries received $1.01 billion and $102 million, respectively, in net proceeds from the issuance of common units. During 2015, we had a net increase in our debt level of $3.11 billion compared to a net increase of $720 million for 2014. We have paid distributions of $1.38 billion to our partners in 2015 compared to $943 million in 2014. We have also paid distributions of $165 million to noncontrolling interests in 2015 compared to $108 million in 2014. In addition, we have received capital contributions of $398 million in cash from noncontrolling interests in 2015 compared to $6 million in 2014. We incurred debt issuance costs of $50 million in 2015 compared to $30 million in 2014.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	June 30, 2015	December 31, 2014
ETP Senior Notes	$15,640	$10,890
Transwestern Senior Notes	782	782
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	465	715
Sunoco Logistics Senior Notes(1)	3,975	3,975
Sunoco LP Senior Notes	800	—
Regency Senior Notes	4,590	5,089
Revolving credit facilities:		
ETP $3.75 billion Revolving Credit Facility due November 2019	—	570
Sunoco Logistics' subsidiary $35 million Revolving Credit Facility due April 2015	—	35
Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020	550	150
Sunoco LP $1.5 billion Revolving Credit Facility due September 2019	725	683
Regency $2.5 billion Revolving Credit Facility due November 25, 2019(2)	—	1,504
Other long-term debt	202	223
Unamortized premiums, net of discounts and fair value adjustments	259	280
Total debt	29,073	25,981
Less: Current maturities of long-term debt	15	1,008
Long-term debt, less current maturities	$29,058	$24,973

(1) Sunoco Logistics' 6.125% senior notes due May 15, 2016 were classified as long-term debt as of June 30, 2015 as Sunoco Logistics has the ability and the intent to refinance such borrowings on a long-term basis.

(2) On April 30, 2015, in connection with the Regency Merger, the Regency Credit Facility was paid off in full and terminated.

ETP Senior Notes

In June 2015, ETP issued $650 million aggregate principal amount of 2.50% senior notes due June 2018, $350 million aggregate principal amount of 4.15% senior notes due October 2020, $1.0 billion aggregate principal amount of 4.75% senior notes due January 2026 and $1.0 billion aggregate principal amount of 6.125% senior notes due December 2045. ETP used the net proceeds of $2.98 billion from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

In March 2015, ETP issued $1.0 billion aggregate principal amount of 4.05% senior notes due March 2025, $500 million aggregate principal amount of 4.90% senior notes due March 2035, and $1.0 billion aggregate principal amount of 5.15% senior notes due March 2045. ETP used the $2.48 billion net proceeds from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

Sunoco LP Senior Notes

In July 2015, Sunoco LP issued $600 million aggregate principal amount of 5.5% senior notes due August 2020. The net proceeds from the offering were used to fund a portion of the cash consideration for Sunoco LP's acquisition of Susser.

In April 2015, Sunoco LP issued $800 million aggregate principal amount of 6.375% senior notes due April 2023. The net proceeds from the offering were used to fund the cash portion of the dropdown of Sunoco, LLC interests and to repay outstanding balances under the Sunoco LP revolving credit facility.

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Regency Debt

Senior Notes

The following table reflects outstanding indebtedness assumed in the Regency Merger:

	April 30, 2015
Regency Senior Notes	$5,088
Regency $2.5 billion Revolving Credit Facility due November 25, 2019[1]	—
Unamortized premiums, net of discounts and fair value adjustments	43
Total debt	$5,131

(1) On April 30, 2015, in connection with the Regency Merger, the Regency Credit Facility was paid off in full and terminated.

On June 1, 2015, Regency redeemed all of the outstanding $499 million aggregate principal amount of its 8.375% senior notes due June 2019.

In July 2015, Regency issued notices of redemption to the holders of the $390 million aggregate principal amount of its 8.375% senior notes due June 2020, with a redemption date of August 13, 2015, and the $400 million aggregate principal amount of its 6.50% senior notes due May 2021, with a redemption date of August 10, 2015.

The Regency senior notes were registered under the Securities Act of 1933 (as amended). Regency may redeem some or all of the Regency senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the Regency senior notes. The balance is payable upon maturity and interest is payable semi-annually.

The senior notes issued by Regency are fully and unconditionally guaranteed, on a joint and several basis, by all of Regency's consolidated subsidiaries, except for ELG and its wholly-owned subsidiaries, Aqua – PVR and ORS. As a result, excluding ELG, Aqua – PVR and ORS, the Regency senior notes effectively rank junior to any future indebtedness of Regency's or its subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the Regency senior notes effectively rank junior to all indebtedness and other liabilities of Regency's existing and future subsidiaries.

On April 30, 2015, in connection with the Regency Merger, Panhandle agreed to fully and unconditionally guarantee (the "Panhandle Guarantee") all of the payment obligations of Regency and Regency Energy Finance Corp. under their $600 million in aggregate principal amount of 4.50% senior notes due November 2023. On May 28, 2015, ETP entered into a supplemental indenture relating to the senior notes pursuant to which it has agreed to become a co-obligor with respect to the payment obligations thereunder. Accordingly, pursuant to the terms of the senior notes, Panhandle's obligations under the Panhandle Guarantee have been released.

The Regency senior notes contain various covenants that limit, among other things, Regency's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $3.75 billion and expires in November 2019. The 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 June 30, 2015, the ETP Credit Facility had no outstanding borrowings.

Sunoco Logistics Credit Facilities

In March 2015, Sunoco Logistics amended and restated its $1.5 billion unsecured credit facility, which was scheduled to mature in November 2018. The amended and restated credit facility is a $2.5 billion unsecured revolving credit agreement (the "Sunoco Logistics Credit Facility"), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature,

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under which the total aggregate commitment may be increased to $3.25 billion under certain conditions. As of June 30, 2015, the Sunoco Logistics Credit Facility had $550 million of outstanding borrowings.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.5 billion revolving credit facility (the "Sunoco LP Credit Facility"), which expires in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP's written request, subject to certain conditions, up to an additional $250 million. As of June 30, 2015, the Sunoco LP Credit Facility had $725 million of outstanding borrowings.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of June 30, 2015.

Contractual Obligations

In connection with the acquisition of Regency, ETP assumed the following long-term debt:

- $400 million notional amount of 5.75% Senior Notes due September 1, 2020;
- $500 million notional amount of 6.5% Senior Notes due July 15, 2021;
- $900 million notional amount of 5.875% Senior Notes due March 1, 2022;
- $700 million notional amount of 5.5% Senior Notes due April 15, 2023;
- $600 million notional amount of 4.5% Senior Notes due November 1, 2023;
- $390 million notional amount of 8.375% Senior Notes due June 1, 2020;
- $400 million notional amount of 6.5% Senior Notes due May 15, 2021;
- $499 million notional amount of .375% Senior Notes due June 1, 2019; and
- $700 million notional amount of 5.0% Senior Notes due October 1, 2022

CASH DISTRIBUTIONS

Cash Distributions Paid by ETP

We expect to use substantially all of our cash provided by operating and financing activities from the Operating Companies to provide distributions to our Unitholders. 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 in our Partnership Agreement) 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, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 6, 2015	February 13, 2015	$0.9950
March 31, 2015	May 8, 2015	May 15, 2015	1.0150
June 30, 2015	August 6, 2015	August 14, 2015	1.0350

The total amounts of distributions declared during the periods presented (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30,	
	2015	2014
Common Units held by public[1]	$950	$546
Common Units held by ETE	48	58
Class H Units held by ETE and ETE Holdings	118	103
General Partner interest held by ETE	15	10
Incentive distributions held by ETE	617	346
IDR relinquishments net of Class I Unit distributions	(55)	(115)
Total distributions declared to the partners of ETP	$1,693	$948

[1] Reflects the impact from Common Units issued in the Regency Merger.

In connection with previous transactions, including the Regency Merger and Sunoco LP Exchange, ETE has agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units.

	Total Year
2015 (remainder)	$56
2016	137
2017	128
2018	105
2019	95

Cash Distributions Paid by Sunoco Logistics

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, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 9, 2015	February 13, 2015	$0.4000
March 31, 2015	May 11, 2015	May 15, 2015	0.4190
June 30, 2015	August 10, 2015	August 14, 2015	0.4380

The total amounts of Sunoco Logistics distributions declared during the periods presented were as follows (all from Available Cash from Sunoco Logistics' operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30,	
	2015	2014
Limited Partners:		
Common units held by public	$157	$101
Common units held by ETP	57	48
General Partner interest held by ETP	6	4
Incentive distributions held by ETP	125	78
Total distributions declared	$345	$231

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Cash Distributions Paid by Sunoco LP

Sunoco LP 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 LP subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 17, 2015	February 27, 2015	$0.6000
March 31, 2015	May 19, 2015	May 29, 2015	0.6450
June 30, 2015	August 18, 2015	August 28, 2015	0.6934

The total amounts of Sunoco LP distributions declared during the periods presented were as follows (all from Available Cash from Sunoco LP's operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30, 2015
Limited Partners:	
Common units held by public	$31
Common and subordinated units held by ETP[(1)]	21
General Partner interest and incentive distributions held by ETP	5
Total distributions declared	$57

(1) Includes Sunoco LP units issued to ETP in connection with Sunoco LP's acquisition of Susser from ETP in July 2015.

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, 2014, 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, 2014. Since December 31, 2014, 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, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power and barrels for natural gas liquids, crude and refined products. Dollar amounts are presented in millions.

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	June 30, 2015			December 31, 2014		
	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):						
Fixed Swaps/Futures	(1,075,000)	$—	$—	(232,500)	$(1)	$—
Basis Swaps IFERC/NYMEX[1]	(4,527,500)	—	—	(13,907,500)	—	—
Options – Calls	5,000,000	—	—	5,000,000	—	—
Power (Megawatt):						
Forwards	373,357	2	1	288,775	—	1
Futures	436,789	(3)	1	(156,000)	2	—
Options – Puts	(581,328)	(4)	1	(72,000)	—	1
Options – Calls	(1,428,154)	4	1	198,556	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	10,327,500	1	—	57,500	(3)	—
Swing Swaps IFERC	23,335,000	—	—	46,150,000	2	1
Fixed Swaps/Futures	(11,577,500)	(17)	7	(34,304,000)	30	10
Forward Physical Contracts	4,424,847	1	—	(9,116,777)	—	3
Natural Gas Liquid and Crude (Bbls) – Forwards/Swaps	(3,730,800)	2	37	(4,417,400)	71	18
Refined Products (Bbls) – Futures	(1,195,000)	—	18	13,745,755	15	11
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(37,555,000)	1	—	(39,287,500)	3	1
Fixed Swaps/Futures	(37,555,000)	38	12	(39,287,500)	48	12

(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.

Interest Rate Risk

As of June 30, 2015, we had $1.88 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $19 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. 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.

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

Term	Type [1]	Notional Amount Outstanding	
		June 30, 2015	December 31, 2014
July 2015[2]	Forward-starting to pay a fixed rate of 3.40% and receive a floating rate	$100	$200
July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	200
July 2017[4]	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	300
July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
July 2019[4]	Forward-starting to pay a fixed rate of 3.25% and receive a floating rate	200	300
December 2018	Pay a floating rate based on 3-month LIBOR and receive a fixed rate of 1.53%	1,200	—
March 2019	Pay a floating rate based on 3-month LIBOR and receive a fixed rate of 1.42%	300	—
February 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	—	200

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

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

(3) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.

(4) Represents the effective date. These forward-starting swaps have terms of 30 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 $245 million as of June 30, 2015. For the $1.50 billion 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 $15 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.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of senior management, including the Chief Executive Officer (“Principal Executive Officer”) and the Chief Financial Officer (“Principal Financial Officer”) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of June 30, 2015 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.

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Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)–15(f) or Rule 15d–15(f) of the Exchange Act) during the three months ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2014 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 June 30, 2015.

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, 2014.

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ITEM 6. EXHIBITS

The exhibits listed below are filed or furnished, as indicated, as part of this report:

Exhibit Number	Description
1.1	Underwriting Agreement dated as of June 18, 2015 among the Partnership, Deutsche Bank Securities Inc., Mitsubishi UFJ Securities (USA), Inc. and Wells Fargo Securities, LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to the Registrant's Form 8-K filed June 23, 2015).
3.1	Amendment No. 10 to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed April 30, 2015).
4.1	Fifteenth Supplemental Indenture dated as of June 23, 2015 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed June 23, 2015).
10.1	Amended and Restated Operating Agreement of Sunoco, LLC, dated effective as of April 1, 2015, by and between ETP Retail Holdings, LLC and Susser Petroleum Operating Company LLC. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 1, 2015).
10.2	Guarantee of Collection, made as of April 1, 2015, by ETP Retail Holdings, LLC to Sunoco LP and Sunoco Finance Corp. (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed on April 1, 2015).
10.3	Support Agreement, made as of April 1, 2015, by and among Sunoco, Inc. (R&M), Sunoco LP, Sunoco Finance Corp. and ETP Retail Holdings, LLC. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 1, 2015).
10.4	Support Agreement, made as of April 1, 2015, by and among Atlantic Refining & Marketing Corp., Sunoco LP, Sunoco Finance Corp. and ETP Retail Holdings, LLC. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 1, 2015).
10.5	Eleventh Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 30, 2015).
10.6	Ninth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed April 30, 2015).
10.7	Sixth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, as guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 30, 2015).
10.8	Eighth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.4 to the Registrant's Form 8-K filed April 30, 2015).
10.9	Second Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.5 to the Registrant's Form 8-K filed April 30, 2015).
10.10	Separation and Non-Solicit Agreement and Full Release of Claims (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed May 14, 2015).

10.11	Seventh Supplemental Indenture, dated as of May 28, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, Energy Transfer Partners, L.P., as co-obligor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed June 1, 2015).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 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.

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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.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document
*	Filed herewith.
**	Furnished herewith.

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SIGNATURE

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

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P.,
its General Partner

By: Energy Transfer Partners, L.L.C.,
its General Partner

Date: August 7, 2015

By: /s/ A. Troy Sturrock
A. Troy Sturrock
Vice President, Controller and Principal Accounting Officer
(duly authorized to sign on behalf of the registrant)