Energy Transfer Partners, L.P.
Form 10-Q
November 09, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 2010

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 and 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 x 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes x 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	x	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 x

At November 3, 2010, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 191,599,549 Common Units

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FORM 10-Q

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Energy Transfer Partners, L.P. and Subsidiaries

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (Energy Transfer Partners or the Partnership) in periodic press releases and some oral statements of Energy Transfer Partners, officials during presentations about the Partnership, include certain forward-looking statements. Statements using words such as anticipate, believe, intend project, plan, expect continue, estimate, forecast, may, will or similar expressions help identify forward-looking statements. Partnership believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such expectations will prove to be correct.

Actual results may differ materially from any results projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management s control. For additional discussion of risks, uncertainties and assumptions, see Part II Other Information Item 1A. Risk Factors in this Quarterly Report on Form 10-Q and our Quarterly Reports on Form 10-Q for the quarters ended March 31 and June 30, 2010, as well as Part I Item 1A. Risk Factors in the Partnership s Report on Form 10-K for the year ended December 31, 2009 filed with the Securities and Exchange Commission (SEC) on February 24, 2010.

Definitions

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

/d	per day
Bbls	barrels
Btu	British thermal unit, an energy measurement. A therm factor is 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
Dth	million British thermal units (dekatherm)
Mcf	thousand cubic feet
MMBtu	million British thermal units
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	September 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 77,700	$ 68,183
Marketable securities	2,270	6,055
Accounts receivable, net of allowance for doubtful accounts of $6,382 and $6,338 as of September 30, 2010 and December 31, 2009, respectively	400,665	566,522
Accounts receivable from related companies	45,774	57,369
Inventories	277,073	389,954
Exchanges receivable	18,473	23,136
Price risk management assets	5,740	12,371
Other current assets	121,605	148,373
Total current assets	949,300	1,271,963
PROPERTY, PLANT AND EQUIPMENT	10,763,239	9,649,405
ACCUMULATED DEPRECIATION	(1,203,104)	(979,158)
	9,560,135	8,670,247
ADVANCES TO AND INVESTMENTS IN AFFILIATES	7,863	663,298
LONG-TERM PRICE RISK MANAGEMENT ASSETS	201	
GOODWILL	772,825	745,505
INTANGIBLES AND OTHER ASSETS, net	424,007	383,959
Total assets	$ 11,714,331	$ 11,734,972

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	September 30, 2010	December 31, 2009
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 275,406	$ 358,997
Accounts payable to related companies	11,777	38,842
Exchanges payable	11,200	19,203
Price risk management liabilities	25	442
Accrued and other current liabilities	491,067	365,168
Current maturities of long-term debt	35,182	40,887
Total current liabilities	824,657	823,539
LONG-TERM DEBT, less current maturities	6,004,646	6,176,918
LONG-TERM PRICE MANAGEMENT LIABILITIES	13,164	
OTHER NON-CURRENT LIABILITIES	138,727	134,807
COMMITMENTS AND CONTINGENCIES (Note 13)		
PARTNERS CAPITAL:		
General Partner	174,497	174,884
Limited Partners:		
Common Unitholders (191,578,586 and 179,274,747 units authorized, issued and outstanding at September 30, 2010 and December 31, 2009, respectively)	4,514,214	4,418,017
Class E Unitholders (8,853,832 units authorized, issued and outstanding held by subsidiary and reported as treasury units)		
Accumulated other comprehensive income	44,426	6,807
Total partners capital	4,733,137	4,599,708
Total liabilities and partners capital	$ 11,714,331	$ 11,734,972

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
REVENUES:				
Natural gas operations	$ 1,082,866	$ 943,975	$ 3,435,521	$ 3,004,163
Retail propane	183,786	162,224	914,372	829,901
Other	23,992	23,397	80,438	77,449
Total revenues	1,290,644	1,129,596	4,430,331	3,911,513
COSTS AND EXPENSES:				
Cost of products sold natural gas operations	666,022	591,797	2,232,867	1,865,914
Cost of products sold retail propane	104,533	80,232	519,796	378,524
Cost of products sold other	6,856	6,119	20,470	18,842
Operating expenses	174,740	158,883	515,021	517,337
Depreciation and amortization	85,612	81,684	252,765	230,461
Selling, general and administrative	44,734	33,534	137,743	143,015
Total costs and expenses	1,082,497	952,249	3,678,662	3,154,093
OPERATING INCOME	208,147	177,347	751,669	757,420
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(101,241)	(101,503)	(309,217)	(284,228)
Equity in earnings of affiliates	595	9,581	10,848	11,751
Gains (losses) on disposal of assets	281	(1,088)	(198)	(1,333)
Gains (losses) on non-hedged interest rate derivatives	(11,963)	(18,241)	(11,963)	32,327
Allowance for equity funds used during construction	12,432	30	18,039	18,618
Impairment of investment in affiliate			(52,620)	
Other, net	1,129	3,433	(3,731)	4,400
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	109,380	69,559	402,827	538,955
Income tax expense (benefit)	1,993	(2,897)	12,486	8,594
NET INCOME	107,387	72,456	390,341	530,361
GENERAL PARTNER S INTEREST IN NET INCOME	97,046	88,927	287,644	266,396
LIMITED PARTNERS INTEREST IN NET INCOME (LOSS)	$ 10,341	$ (16,471)	$ 102,697	$ 263,965

BASIC NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ 0.05	$ (0.10)	$ 0.54	$ 1.60
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	185,247,021	168,815,563	186,761,917	164,183,538
DILUTED NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ 0.05	$ (0.10)	$ 0.53	$ 1.59
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	186,214,685	168,815,563	187,708,683	164,886,492

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Net income	$ 107,387	$ 72,456	$ 390,341	$ 530,361
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(5,388)	871	(18,006)	(8,822)
Change in value of derivative instruments accounted for as cash flow hedges	34,776	(15,150)	59,410	(15,200)
Change in value of available-for-sale securities	(732)	3,049	(3,785)	6,757
	28,656	(11,230)	37,619	(17,265)
Comprehensive income	$ 136,043	$ 61,226	$ 427,960	$ 513,096

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2010

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2009	$ 174,884	$ 4,418,017	$ 6,807	$ 4,599,708
Redemption of units in connection with MEP Transaction (See Note 8)	(3,700)	(608,340)		(612,040)
Distributions to partners	(293,282)	(501,506)		(794,788)
Units issued for cash		1,086,991		1,086,991
Capital contribution from General Partner (payment of contributions receivable)	8,932			8,932
Distributions on unvested unit awards		(3,398)		(3,398)
Tax effect of remedial income allocation from tax amortization of goodwill		(2,552)		(2,552)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings		21,386		21,386
Non-cash executive compensation	19	919		938
Other comprehensive income			37,619	37,619
Net income	287,644	102,697		390,341
Balance, September 30, 2010	$ 174,497	$ 4,514,214	$ 44,426	$ 4,733,137

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 1,102,896	$ 796,017
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(156,388)	(6,244)
Capital expenditures (excluding allowance for equity funds used during construction)	(1,036,903)	(703,461)
Contributions in aid of construction costs	12,048	5,251
Advances to affiliates, net of repayments	(6,046)	(534,500)
Proceeds from the sale of assets	13,742	13,235
Net cash used in investing activities	(1,173,547)	(1,225,719)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	809,949	2,287,035
Principal payments on debt	(1,007,617)	(1,768,079)
Net proceeds from issuance of Limited Partner units	1,086,991	578,924
Capital contribution from General Partner	8,932	3,354
Distributions to partners	(794,788)	(705,736)
Redemption of units	(23,299)	
Debt issuance costs		(7,639)
Net cash provided by financing activities	80,168	387,859
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	9,517	(41,843)
CASH AND CASH EQUIVALENTS, beginning of period	68,183	91,902
CASH AND CASH EQUIVALENTS, end of period	$ 77,700	$ 50,059

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Tabular dollar amounts, except per unit data, are in thousands)

(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 2009, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners, L.P., and its subsidiaries (Energy Transfer Partners, the Partnership, we or ETP) as of September 30, 2010 and for the three and nine months ended September 30, 2010 and 2009, have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership s operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners, and its subsidiaries as of September 30, 2010, and the Partnership s results of operations and cash flows for the three and nine months ended September 30, 2010 and 2009. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2009, as filed with the SEC on February 24, 2010.

Certain prior period amounts have been reclassified to conform to the 2010 presentation. These reclassifications had no impact on net income or total partners capital.

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

Business Operations

In order to simplify the obligations of Energy Transfer Partners, under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the Operating Companies) as follows:

La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.

Energy Transfer Interstate Holdings, LLC (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 Pipeline Company, LLC (Transwestern), a Delaware limited liability company engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

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ETC Fayetteville Express Pipeline, LLC (ETC FEP), a Delaware limited liability company formed to engage in interstate transportation of natural gas.

ETC Tiger Pipeline, LLC (ETC Tiger), a Delaware limited liability company formed to engage in interstate transportation of natural gas.

ETC Compression, LLC (ETC Compression), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

Heritage Operating, L.P. (HOLP), a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.

Titan Energy Partners, L.P. (Titan), a Delaware limited partnership also engaged in retail propane operations.

2. ESTIMATES:

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

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

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

3. ACQUISITIONS:

In March 2010, we purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, we recorded customer contracts of $68.2 million and goodwill of $27.3 million. See further discussion at Note 6.

4. CASH, CASH EQUIVALENTS AND SUPPLEMENTAL CASH FLOW INFORMATION:

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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Net cash provided by operating activities is comprised of the following:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net income	$ 390,341	$ 530,361
Reconciliation of net income to net cash provided by operating activities:		
Impairment of investment in affiliate	52,620	
Proceeds from termination of interest rate derivatives	26,495	
Depreciation and amortization	252,765	230,461
Amortization of finance costs charged to interest	7,216	6,386
Non-cash unit-based compensation expense	21,422	20,942
Non-cash executive compensation expense	938	938
Deferred income taxes	4,492	3,663
Losses on disposal of assets	198	1,333
Allowance for equity funds used during construction	(18,039)	(18,618)
Distributions on unvested awards	(3,398)	(2,072)
Distributions in excess of (less than) equity in earnings of affiliates, net	20,765	(5,696)
Other non-cash	2,427	4,033
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	166,064	235,239
Accounts receivable from related companies	11,596	(17,882)
Inventories	113,568	51,249
Exchanges receivable	4,663	29,775
Other current assets	26,796	(10,573)
Intangibles and other assets	4,560	(1,977)
Accounts payable	(86,291)	(109,479)
Accounts payable to related companies	(7,253)	(27,150)
Exchanges payable	(8,003)	(32,236)
Accrued and other current liabilities	58,925	8,582
Other non-current liabilities	(600)	669
Price risk management assets and liabilities, net	60,629	(101,931)
Net cash provided by operating activities	$ 1,102,896	$ 796,017

Non-cash investing and financing activities are as follows:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 55,013	$ 64,530
Transfer of MEP joint venture interest in exchange for redemption of Common Units	$ 588,741	$
NON-CASH FINANCING ACTIVITIES:		

Capital contributions receivable from general partner	$		$	8,932
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$	618	$	17,113

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5. INVENTORIES:

Inventories consisted of the following:

	September 30, 2010	December 31, 2009
Natural gas and NGLs, excluding propane	$ 94,514	$ 157,103
Propane	57,018	66,686
Appliances, parts and fittings and other	125,541	166,165
Total inventories	$ 277,073	$ 389,954

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

6. GOODWILL, INTANGIBLES AND OTHER ASSETS:

A net increase in goodwill of $27.3 million was recorded during the nine months ended September 30, 2010, primarily due to the acquisition of the natural gas gathering company referenced in Note 3. This additional goodwill is expected to be deductible for tax purposes. In addition, we recorded customer contracts of $68.2 million with useful lives of 46 years.

Components and useful lives of intangibles and other assets were as follows:

	September 30, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 244,808	$ (70,624)	$ 176,858	$ (58,761)
Noncompete agreements (3 to 15 years)	21,592	(11,965)	24,139	(12,415)
Patents (9 years)	750	(97)	750	(35)
Other (10 to 15 years)	1,320	(466)	478	(397)
Total amortizable intangible assets	268,470	(83,152)	202,225	(71,608)
Non-amortizable intangible assets Trademarks	76,086		75,825	
Total intangible assets	344,556	(83,152)	278,050	(71,608)
Other assets:				
Financing costs (3 to 30 years)	67,795	(30,401)	68,597	(24,774)
Regulatory assets	107,233	(13,476)	101,879	(9,501)
Other	31,452		41,316	
Total intangibles and other assets	$ 551,036	$ (127,029)	$ 489,842	$ (105,883)

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Aggregate amortization expense of intangibles and other assets was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Reported in depreciation and amortization	$ 5,124	$ 6,243	$ 15,418	$ 15,935
Reported in interest expense	$ 2,159	$ 2,125	$ 6,489	$ 6,051

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

Years Ending December 31:	
2011	$ 26,916
2012	23,330
2013	17,899
2014	16,890
2015	14,566

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review goodwill and non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of August 31 for reporting units within our intrastate transportation and storage, midstream and retail propane operations. We have not completed our annual impairment tests for 2010 and have not recorded any impairments related to amortizable intangible assets during the nine months ended September 30, 2010.

7. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at September 30, 2010 was $6.94 billion and $6.04 billion, respectively. At December 31, 2009, the aggregate fair value and carrying amount of long-term debt was $6.75 billion and $6.22 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our condensed 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 over-the-counter (OTC) commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of September 30, 2010 and December 31, 2009 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at September 30, 2010 Using Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 2,270	$ 2,270	$
Interest rate derivatives	201		201
Commodity derivatives:			
Natural Gas:			
Fixed Swaps/Futures	37,047	36,992	55
Options Puts	29,025		29,025
Propane Forwards/Swaps	5,685		5,685
Total commodity derivatives	71,757	36,992	34,765
Total Assets	$ 74,228	$ 39,262	$ 34,966
Liabilities:			
Interest rate derivatives	$ (13,164)	$	$ (13,164)
Commodity derivatives:			
Natural Gas:			
Basic Swaps IFERC/NYMEX	(1,153)	(1,153)	
Swing Swaps IFERC	(938)	(913)	(25)
Options Calls	(1,576)		(1,576)
Total commodity derivatives	(3,667)	(2,066)	(1,601)
Total Liabilities	$ (16,831)	$ (2,066)	$ (14,765)

	Fair Value Total	Fair Value Measurements at December 31, 2009 Using Quoted Prices in Active Markets for Identical Assets	Significant Observable Inputs (Level 2)

		and Liabilities (Level 1)	
Assets:			
Marketable securities	$ 6,055	$ 6,055	$
Commodity derivatives	32,479	20,090	12,389
Liabilities:			
Commodity derivatives	(8,016)	(7,574)	(442)
Total	$ 30,518	$ 18,571	$ 11,947

In conjunction with the MEP Transaction, we adjusted the investment in MEP to fair value based on the present value of the expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment of $52.6 million. Substantially all of our investment was transferred to ETE. See Note 8.

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8. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

On May 26, 2010, we completed the transfer of the membership interests in ETC Midcontinent Express Pipeline III, L.L.C. (ETC MEP III) to ETE pursuant to the Redemption and Exchange Agreement between us and ETE, dated as of May 10, 2010 (the MEP Transaction). ETC MEP III owns a 49.9% membership interest in Midcontinent Express Pipeline LLC (MEP), our joint venture with Kinder Morgan Energy Partners, L.P. (KMP) that owns and operates the Midcontinent Express Pipeline. In exchange for the membership interests in ETC MEP III, we redeemed 12,273,830 ETP common units that were previously owned by ETE. We also paid $23.3 million to ETE upon closing of the MEP Transaction for adjustments related to capital expenditures and working capital changes of MEP. Subsequent to September 30, 2010, we received a cash closing adjustment of $8.2 million from ETE. ETE has an option that cannot be exercised until May 27, 2011, to acquire the membership interests in ETC Midcontinent Express Pipeline II, L.L.C. (ETC MEP II). ETC MEP II owns a 0.1% membership interest in MEP. In conjunction with this transfer of our interest in ETC MEP III, we recorded a non-cash charge of approximately $52.6 million during the three months ended June 30, 2010 to reduce the carrying value of our interest in ETC MEP III to its estimated fair value.

As part of the MEP Transaction, on May 26, 2010, ETE completed the contribution of the membership interests in ETC MEP III and the assignment of its rights under the option to acquire the membership interests in ETC MEP II to a subsidiary of Regency Energy Partners LP (Regency) in exchange for 26,266,791 Regency common units. In addition, ETE acquired a 100% equity interest in the general partner entities of Regency from an affiliate of GE Energy Financial Services, Inc.

We continue to guarantee 50% of MEP s obligations under MEP s $175.4 million senior revolving credit facility, with the remaining 50% of MEP s obligations guaranteed by KMP. Regency has agreed to indemnify us for any costs related to the guaranty of payments under this facility. See Note 13.

Fayetteville Express Pipeline LLC

We are party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Panola County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC (FEP), the entity formed to construct, own and operate this pipeline, received Federal Energy Regulatory Commission (FERC) approval of its application for authority to construct and operate this pipeline. In July 2010, FERC granted a rehearing of the December 2009 order and allowed FEP to include in its initial rate proposed allowance for funds used during construction that accrued prior to filing its application. The pipeline began interim service in October 2010 and is expected to be fully operational in December 2010. Upon completion of all facilities, the pipeline is expected to have an initial capacity of 2.0 Bcf/d. As of September 30, 2010, FEP has secured binding commitments for a minimum of 10 years for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America (NGPL) in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

9. NET INCOME (LOSS) PER LIMITED PARTNER UNIT:

Our net income (loss) 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 our General Partner, the holder of the incentive distribution rights (IDRs) pursuant to our partnership agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net income	$ 107,387	$ 72,456	$ 390,341	$ 530,361
General Partner s interest in net income	97,046	88,927	287,644	266,396
Limited Partners interest in net income (loss)	10,341	(16,471)	102,697	263,965
Additional earnings allocated from General Partner	161	185	790	185
Distributions on employee unit awards, net of allocation to General Partner	(1,142)	(668)	(3,451)	(2,017)
Net income (loss) available to Limited Partners	$ 9,360	$ (16,954)	$ 100,036	$ 262,133
Weighted average Limited Partner units basic	185,247,021	168,815,563	186,761,917	164,183,538
Basic net income (loss) per Limited Partner unit	$ 0.05	$ (0.10)	$ 0.54	$ 1.60
Weighted average Limited Partner units	185,247,021	168,815,563	186,761,917	164,183,538
Dilutive effect of unvested Unit Awards	967,664		946,766	702,954
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	186,214,685	168,815,563	187,708,683	164,886,492
Diluted net income (loss) per Limited Partner unit	$ 0.05	$ (0.10)	$ 0.53	$ 1.59

Based on the declared distribution rate of $0.89375 per Common Unit, distributions paid for the three months ended September 30, 2009, were $249.5 million in total, which exceeded net income for the period by $177.0 million. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended September 30, 2009, and as a result, a net loss was allocated to the Limited Partners for the period.

10. DEBT OBLIGATIONS:

Revolving Credit Facilities

ETP Credit Facility

We maintain a revolving credit facility (the ETP Credit Facility) that provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest, at our option, at a Eurodollar rate plus an applicable margin or a base rate. The base rate used to calculate interest on base rate loans will be calculated using the greater of a prime rate or a federal funds effective rate plus 0.50%. The applicable margin for Eurodollar loans ranges from 0.30% to 0.70% based upon ETP s credit rating and is currently 0.55% (0.60% if facility usage exceeds 50%). The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

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As of September 30, 2010, there were no outstanding borrowings under the ETP Credit Facility. Taking into account letters of credit of approximately $22.4 million, the amount available for future borrowings was $1.98 billion.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the HOLP Credit Facility) available to HOLP through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP s subsidiaries secure the HOLP Credit Facility. At September 30, 2010, the HOLP credit facility had no outstanding balance in revolving credit loans and outstanding letters of credit of $0.5 million. The amount available for borrowing as of September 30, 2010 was $74.5 million.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at September 30, 2010.

11. PARTNERS CAPITAL:
Common Units Issued

The change in Common Units during the nine months ended September 30, 2010 was as follows:

	Number of Units
Balance, December 31, 2009	179,274,747
Common Units issued in connection with public offerings	20,700,000
Common Units issued in connection with the Equity Distribution Agreement	3,842,283
Issuance of Common Units under equity incentive plans	35,386
Redemption of units in connection with MEP Transaction (See Note 8)	(12,273,830)
Balance, September 30, 2010	191,578,586

In January 2010, we issued 9,775,000 Common Units through a public offering for net proceeds of $423.6 million. In August 2010, we issued 10,925,000 Common Units through a public offering for net proceeds of $489.4 million. The proceeds from these offerings were used primarily to repay borrowings under the ETP Credit Facility and to fund capital expenditures related to pipeline projects.

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC (UBS). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, Common Units having an aggregate value of up to $300.0 million. Sales of the units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During the nine months ended September 30, 2010, we issued 3,842,283 of our Common Units pursuant to this agreement. The proceeds of approximately $174.1 million, net of commissions, were used for general partnership purposes. Approximately $40.6 million of our Common Units remain available to be issued under the agreement based on trades initiated through September 30, 2010.

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Quarterly Distributions of Available Cash

Distributions paid by us are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distributions Per Common Unit
December 31, 2009	February 8, 2010	February 15, 2010	$ 0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375
June 30, 2010	August 9, 2010	August 16, 2010	0.89375

On October 28, 2010, ETP declared a cash distribution for the three months ended September 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on November 15, 2010 to Unitholders of record at the close of business on November 8, 2010.

The total amounts of distributions declared during the nine months ended September 30, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Nine Months Ended September 30,	
	2010	2009
Limited Partners:		
Common Units	$ 503,582	$ 460,132
Class E Units	9,363	9,363
General Partner Interest	14,634	14,626
Incentive Distribution Rights	279,823	256,530
Total distributions declared	$ 807,402	$ 740,651

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income (AOCI), net of tax:

	September 30, 2010	December 31, 2009
Net gains on commodity related hedges	$ 43,270	$ 1,991
Net losses on interest rate hedges		(125)
Unrealized gains on available-for-sale securities	1,156	4,941
Total AOCI, net of tax	$ 44,426	$ 6,807

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12. INCOME TAXES:

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Current expense (benefit):				
Federal	$ (3,794)	$ (88)	$ (877)	$ (5,195)
State	1,450	3,231	8,871	10,126
Total	(2,344)	3,143	7,994	4,931
Deferred expense (benefit):				
Federal	4,357	(5,670)	4,778	3,472
State	(20)	(370)	(286)	191
Total	4,337	(6,040)	4,492	3,663
Total income tax expense (benefit)	$ 1,993	$ (2,897)	$ 12,486	$ 8,594
Effective tax rate	1.82%	(4.16)%	3.10%	1.59%

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

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

Regulatory Matters

In August 2009, we filed an application for FERC authority to construct and operate the Tiger pipeline. The application was approved in April 2010 and construction began in June 2010. Subject to regulatory approvals, we expect initial service on the Tiger pipeline to commence in the fourth quarter of 2010. In February 2010, we announced a 400 MMcf/d expansion of the Tiger pipeline. In June 2010, we filed an application for FERC authority to construct, own and operate that expansion, which remains under review before the FERC.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (NGA) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern s tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

Guarantees

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the MEP Facility), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions. Although we transferred substantially all of our interest in MEP on May 26, 2010, as discussed above in Note 8, we will continue to guarantee 50% of MEP s obligations under this facility through the maturity of the facility in February 2011. Regency has agreed to indemnify us for any costs related to the guarantee of payments under this facility.

Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of September 30, 2010, MEP had $82.2 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP s outstanding borrowings and letters of credit were $41.1 million and $16.6 million, respectively, as of September 30, 2010. The weighted average interest rate on the total amount outstanding as of September 30, 2010 was 0.9%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the FEP Facility). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012 and amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of September 30, 2010, FEP had $847.0 million of outstanding borrowings issued under the FEP Facility and our contingent obligation with respect to our 50% guarantee of FEP s outstanding borrowings was $423.5 million as of September 30, 2010. The weighted average interest rate on the total amount outstanding as of September 30, 2010 was 3.3%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts. In addition, we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a contract to purchase not less than 90.0 million gallons of propane per year that expires in 2015. 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 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.0 million and $6.0 million for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, rental expense for operating leases totaled approximately $16.3 million and $17.5 million, respectively.

Our propane operations have an agreement with a subsidiary of Enterprise GP Holdings L.P. (see Note 15) to supply a portion of our propane requirements. The agreement expired in March 2010; however, our propane operations executed a five year extension as of April 2010. The extension will continue until March 2015 and includes an option to extend the agreement for an additional year.

We have commitments to make capital contributions to our joint ventures. For the joint ventures that we currently have interests in, we expect that future capital contributions will be between $10 million and $15 million, which we expect to contribute primarily during the last three months of 2010.

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 propane are flammable, combustible gases. 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.

FERC and Related Matters. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that we violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC s Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP s trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC s Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against us by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process of potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims, solely for purposes of participation in this fund allocation process, and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ s recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against ETP related to this matter.

In addition to the claims that were settled pursuant to the ALJ fund allocation process discussed above, ETP was a party in three legal proceedings that asserted contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006. In all three of these legal proceedings, we have received favorable rulings at the lower court and appellate court levels that have resulted in the dismissal of all claims made in these proceedings, and no further appeals or motions for rehearing may be pursued by the plaintiffs in these proceedings except with respect to one proceeding as to which the plaintiffs may seek review at the U.S. Supreme Court, which action we believe is unlikely to occur.

We are expensing the legal fees, consultants fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. The after-tax impact of the settlement was less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies and American Electric Power Corporation (AEP), were defendants in litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel storage facility (Cushion Gas). This litigation is referred to as the Cushion Gas Litigation. In 2004, ETC OLP (a subsidiary of ETP) acquired the HPL Entities from AEP, at which time AEP agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP expects that it will be indemnified for any monetary damages awarded to B of A under this court decision.

Other Matters. In addition to those matters described above, 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, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of September 30, 2010 and December 31, 2009, accruals of approximately $10.4 million and $11.1 million, respectively, were recorded related to deductibles. 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 it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

No amounts have been recorded in our September 30, 2010 or December 31, 2009 consolidated balance sheets for our contingencies and current litigation matters, other than accruals related to environmental matters and deductibles.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that can 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 natural gas pipeline, gathering, treating, compressing, blending and processing business. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage, and to limit the

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financial liability, which could result from such events. However, the risk of environmental or other damage is inherent in the transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products, as it is with other entities engaged in similar businesses.

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 clean-up technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of September 30, 2010 and December 31, 2009, accruals on an undiscounted basis of $12.3 million and $12.6 million, respectively, were recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities related to environmental matters.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for clean-up costs.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean-up activities include remediation of several compressor sites on the Transwestern system for historical contamination associated with polychlorinated biphenyls (PCBs) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.3 million, which is included in the aggregate environmental accruals. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

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

Environmental regulations were recently modified for the U.S. Environmental Protection Agency s (the EPA) Spill Prevention, Control and Countermeasures program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our September 30, 2010 or December 31, 2009 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

By March 2013, the Texas Commission on Environmental Quality is required to develop another plan to address the recent change in the ozone standard from 0.08 parts per million, or ppm, to 0.075 ppm and the EPA recently proposed lowering the standard even further, to somewhere in between 0.06 and 0.07 ppm. These efforts may result in the adoption of new regulations that may require additional nitrogen oxide emissions reductions.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation (DOT) under the Pipeline Hazardous Materials Safety Administration (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

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testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended September 30, 2010 and 2009, $5.8 million and $9.3 million, respectively, of capital costs and $3.9 million and $3.6 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the nine months ended September 30, 2010 and 2009, $10.8 million and $24.6 million, respectively, of capital costs and $10.2 million and $12.6 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act, also known as 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.

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

14. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.

- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage and interstate segments to hedge the sales price of retention and operational gas sales and hedge location price differentials related to the transportation of natural gas.

- Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, 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 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

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inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdrawal of natural gas.

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

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

The following table details the outstanding commodity-related derivatives:

	September 30, 2010		December 31, 2009	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(33,870,000)	2010-2011	72,325,000	2010-2011
Swing Swaps IFERC (MMBtu)	11,735,000	2010-2011	(38,935,000)	2010
Fixed Swaps/Futures (MMBtu)	(250,000)	2010-2011	4,852,500	2010-2011
Options Puts (MMBtu)	440,000	2010-2011	2,640,000	2010
Options Calls (MMBtu)	(3,440,000)	2010-2011	(2,640,000)	2010
Propane:				
Forwards/Swaps (Gallons)			6,090,000	2010
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(10,060,000)	2010-2011	(22,625,000)	2010
Fixed Swaps/Futures (MMBtu)	(20,160,000)	2010-2011	(27,300,000)	2010
Hedged Item Inventory (MMBtu)	20,160,000	2010	27,300,000	2010
Cash Flow Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(4,445,000)	2010-2011	(13,225,000)	2010
Fixed Swaps/Futures (MMBtu)	(7,265,000)	2010-2011	(22,800,000)	2010
Options Puts (MMBtu)	22,680,000	2011-2012		
Options Calls (MMBtu)	(22,680,000)	2011-2012		
Propane:				
Forwards/Swaps (Gallons)	58,086,000	2010-2011	20,538,000	2010

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We expect gains of $36.6 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps in order to achieve our 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.

In May and August 2010, we terminated interest rate swaps with total notional amounts of $750.0 million and $350.0 million, respectively, for proceeds of $15.4 million and $11.1 million, respectively. These swaps were designated as fair value hedges. In connection with the swap terminations, $9.7 million and $10.4 million of previously recorded fair value adjustments to hedged long-term debt will be amortized as a reduction of interest expense through February 2015 and July 2013, respectively. The unamortized balance remaining related to these swaps was $18.7 million as of September 30, 2010.

In August 2010, we de-designated $200.0 million of total notional amounts of forward-starting interest rate swaps previously designated as cash flow hedges. These swaps remain outstanding as of September 30, 2010, along with additional swaps with a total notional amount of $200.0 million entered into during the three months ended September 30, 2010. These forward starting swaps, which are not designated as hedges for accounting purposes, begin in August 2012 and we will pay a weighted average fixed rate of 3.64% and receive a floating rate.

In addition to interest rate swaps, we also periodically enter into interest rate swaptions that enable counterparties to exercise options to enter into interest rate swaps with us. Swaptions may be utilized when our targeted benchmark interest rate for anticipated debt issuance is not attainable at the time in the interest rate swap market. Upon issuance of a swaption, we receive a premium, which we recognize over the term of the swaption to Gains (losses) on non-hedged interest rate derivatives in the condensed consolidated statements of operations. No swaptions were outstanding as of September 30, 2010. In October 2010, the Partnership sold a swaption with a notional amount of $100.0 million and maturity date of December 31, 2010 to enter into a swap that, if exercised, would lock in the rate on a portion of anticipated debt issuances.

Derivative Summary

The following table provides a balance sheet overview of the Partnership s derivative assets and liabilities as of September 30, 2010 and December 31, 2009:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	September 30, 2010	December 31, 2009	September 30, 2010	December 31, 2009
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 57,648	$ 669	$ (1,732)	$ (24,035)
Commodity derivatives	5,921	8,443	(181)	(201)
	63,569	9,112	(1,913)	(24,236)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	66,113	72,851	(59,654)	(36,950)
Commodity derivatives		3,928	(25)	(241)
Interest rate derivatives	201		(13,164)	
	66,314	76,779	(72,843)	(37,191)

Total derivatives	$ 129,883	$ 85,891	$ (74,756)	$ (61,427)

The commodity derivatives (margin deposits) are recorded in Other current assets on our condensed consolidated balance sheets. The remainder of the derivatives are recorded in Price risk management assets/liabilities.

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

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the condensed consolidated balance sheets. The Partnership had net deposits with counterparties of $58.7 million and $79.7 million as of September 30, 2010 and December 31, 2009, respectively.

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

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$ 36,035	$ (15,146)	$ 60,992	$ (15,282)
Interest rate derivatives	(1,162)		(1,367)	
Total	$ 34,873	$ (15,146)	$ 59,625	$ (15,282)

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ 6,780	$ (847)	$ 19,153	$ 8,702
Interest rate derivatives	Interest expense	(1,635)	71	(1,493)	215
Total		$ 5,145	$ (776)	$ 17,660	$ 8,917

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ 241	$ (95)	$ 346	$ (95)
Interest rate derivatives	Interest expense				

Total	$ 241	$ (95)	$ 346	$ (95)

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	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ 9,968	$ (20,909)	$ 9,001	$ (8,411)
Interest rate derivatives	Interest expense				
Total		$ 9,968	$ (20,909)	$ 9,001	$ (8,411)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Derivatives not designated as hedging instruments:					
Commodity derivatives	Cost of products sold	$ 9,438	$ 30,346	$ 10,110	$ 87,349
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	(11,963)	(18,241)	(11,963)	32,327
Total		$ (2,525)	$ 12,105	$ (1,853)	$ 119,676

We recognized $12.5 million of unrealized gains and $13.5 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended September 30, 2010 and 2009, respectively. We recognized $32.8 million and $32.7 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the nine months ended September 30, 2010 and 2009, respectively. For the three months ended September 30, 2010 and 2009, we recognized unrealized gains of $8.2 million and unrealized losses of $16.4 million, respectively, on commodity derivatives and related hedged inventory in fair value hedging relationships. For the nine months ended September 30, 2010 and 2009, we recognized unrealized losses of $35.3 million and $3.9 million, respectively, on commodity derivatives and related hedged inventory in fair value hedging relationships.

Credit Risk

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

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty performance.

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 condensed consolidated balance sheet and recognized in net income or other comprehensive income.

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15. RELATED PARTY TRANSACTIONS:

As discussed in Note 8, Regency became a related party on May 26, 2010. Regency provides us with contract compression services. For the three months ended September 30, 2010, we recorded revenue of $0.9 million, cost of products sold of $0.7 million and operating expenses of $0.2 million related to transactions with Regency. For the period from May 26, 2010 to September 30, 2010, we recorded revenue of $0.9 million, costs of products sold of $1.4 million and operating expenses of $0.4 million related to transactions with Regency.

We recorded $2.6 million and $0.1 million from ETE for the provision of various general and administrative services for ETE s benefit for the three months ended September 30, 2010 and 2009, respectively. We recorded $3.7 million and $0.4 million from ETE related to these services for the nine months ended September 30, 2010 and 2009, respectively.

Enterprise GP Holdings L.P. and its subsidiaries (collectively Enterprise) are considered to be related parties to us due to equity interests that Enterprise holds in ETE and its general partner. We and Enterprise transport natural gas on each other s pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. The following table presents sales to and purchase from Enterprise:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Natural Gas Operations:				
Sales	$ 126,992	$ 118,272	$ 402,238	$ 283,346
Purchases	396	12,958	13,928	29,304
Propane Operations:				
Sales	262	2,815	11,228	14,323
Purchases	58,642	44,022	276,821	220,245

Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that was extended until March 2015, and includes an option to extend the agreement for an additional year. As of December 31, 2009, Titan had forward mark-to-market derivatives for approximately 6.1 million gallons of propane at a fair value asset of $3.3 million with Enterprise. All of these forward contracts were settled as of June 30, 2010. In addition, as of September 30, 2010 and December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 58.1 million and 20.5 million gallons of propane at a fair value asset of $5.7 million and $8.4 million, respectively, with Enterprise.

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

	September 30, 2010	December 31, 2009
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$ 35,175	$ 47,005
Propane Operations	407	3,386
Other	10,192	6,978
Total accounts receivable from related parties	$ 45,774	$ 57,369
Accounts payable to related parties:		
Enterprise:		
Natural Gas Operations	$ 1,561	$ 3,518
Propane Operations	8,209	31,642
Other	2,007	3,682

Total accounts payable to related parties	$	11,777	$	38,842

The net imbalance payable from Enterprise was $32 thousand and $0.7 million as of September 30, 2010 and December 31, 2009, respectively.

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16. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	September 30, 2010	December 31, 2009
Deposits paid to vendors	$ 58,710	$ 79,694
Prepaid and other	62,895	68,679
Total other current assets	$ 121,605	$ 148,373

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	September 30, 2010	December 31, 2009
Interest payable	$ 113,784	$ 136,222
Customer advances and deposits	111,374	88,430
Accrued capital expenditures	55,013	46,134
Accrued wages and benefits	48,582	25,202
Taxes other than income taxes	70,507	23,294
Income taxes payable	4,607	3,401
Deferred income taxes	189	
Other	87,011	42,485
Total accrued and other current liabilities	$ 491,067	$ 365,168

17. REPORTABLE SEGMENTS:

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

natural gas operations consisting of:

- intrastate transportation and storage;
- interstate transportation; and

- midstream.

retail propane and other retail propane related operations.

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We evaluate the performance of our operating segments based on operating income, which includes allocated selling, general and administrative expenses. The following tables present the financial information by segment for the following periods:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 529,507	$ 364,087	$ 1,662,037	$ 1,192,564
Intersegment revenues	369,487	102,626	952,336	396,734
	898,994	466,713	2,614,373	1,589,298
Interstate transportation revenues from external customers	74,659	71,415	213,007	203,349
Midstream:				
Revenues from external customers	458,381	507,721	1,484,211	1,607,497
Intersegment revenues	416,703	65,345	945,438	142,969
	875,084	573,066	2,429,649	1,750,466
Retail propane and other retail propane related revenues from external customers	205,833	184,287	987,114	902,471
All other:				
Revenues from external customers	22,264	2,086	83,962	5,632
Intersegment revenues	1,325	372	3,706	372
	23,589	2,458	87,668	6,004
Eliminations against operating expenses	(84)		(252)	
Eliminations against cost of products sold	(787,431)	(168,343)	(1,901,228)	(540,075)
Total revenues	$ 1,290,644	$ 1,129,596	$ 4,430,331	$ 3,911,513
Cost of products sold:				
Intrastate transportation and storage	$ 660,107	$ 278,868	$ 1,930,798	$ 895,433
Midstream	775,769	480,746	2,138,125	1,510,030
Retail propane and other retail propane related	109,910	85,028	534,800	393,019
All other	19,056	1,849	70,638	4,873
Eliminations	(787,431)	(168,343)	(1,901,228)	(540,075)
Total cost of products sold	$ 777,411	$ 678,148	$ 2,773,133	$ 2,263,280
Depreciation and amortization:				
Intrastate transportation and storage	$ 29,340	$ 27,188	$ 87,484	$ 78,080
Interstate transportation	12,643	12,521	37,856	36,017
Midstream	21,592	18,091	62,209	51,792
Retail propane and other retail propane related	20,609	23,031	60,994	63,477
All other	1,428	853	4,222	1,095
Total depreciation and amortization	$ 85,612	$ 81,684	$ 252,765	$ 230,461
Operating income (loss):				

Intrastate transportation and storage	$ 133,750	$ 109,781	$ 395,772	$ 410,425
Interstate transportation	34,576	41,610	98,338	101,755
Midstream	52,793	43,414	154,990	96,603
Retail propane and other retail propane related	(13,053)	(16,550)	107,285	152,079
All other	(2,601)	(3,021)	(3,963)	(4,803)
Selling, general and administrative expenses not allocated to segments	2,682	2,113	(753)	1,361
Total operating income	$ 208,147	$ 177,347	$ 751,669	$ 757,420

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	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (101,241)	$ (101,503)	$ (309,217)	$ (284,228)
Equity in earnings of affiliates	595	9,581	10,848	11,751
Gains (losses) on disposal of assets	281	(1,088)	(198)	(1,333)
Gains (losses) on non-hedged interest rate derivatives	(11,963)	(18,241)	(11,963)	32,327
Allowance for equity funds used during construction	12,432	30	18,039	18,618
Impairment of investment in affiliate			(52,620)	
Other income, net	1,129	3,433	(3,731)	4,400
Income tax expense (benefit)	(1,993)	2,897	(12,486)	(8,594)
	(100,760)	(104,891)	(361,328)	(227,059)
Net income	$ 107,387	$ 72,456	$ 390,341	$ 530,361

	As of September 30, 2010	As of December 31, 2009
Total assets:		
Intrastate transportation and storage	$ 4,787,477	$ 4,901,102
Interstate transportation	3,281,738	3,313,837
Midstream	1,716,877	1,523,538
Retail propane and other retail propane related	1,681,240	1,784,353
All other	246,999	212,142
Total	$ 11,714,331	$ 11,734,972

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 72,797	$ 362,816
Interstate transportation	743,197	127,927
Midstream	269,533	76,408
Retail propane and other retail propane related	46,264	45,904
All other	8,710	29,404
Total	$ 1,140,501	$ 642,459

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

(Tabular dollar amounts are in thousands)

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 24, 2010. Our Management s Discussion and Analysis includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Item 1A. Risk Factors included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2009.

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

Overview

Our activities are primarily conducted through our operating subsidiaries: La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP); Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern), ETC Fayetteville Express Pipeline, LLC (ETC FEP), and ETC Tiger Pipeline, LLC (ETC Tiger); ETC Compression, LLC (ETC Compression); Heritage Operating, L.P. (HOLP); and Titan Energy Partners, L.P. (Titan).

General

Our primary objective is to increase the level of our cash distributions over time by pursuing a business strategy that is currently focused on growing our natural gas midstream and intrastate transportation and storage businesses (including transportation, gathering, compression, treating, processing, storage and marketing) and our propane business through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain additional businesses or assets. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from operations.

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

Our principal operations are conducted in the following segments:

- Intrastate transportation and storage Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that primarily impact our interruptible business are receipt points between West Texas to East Texas. When basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and/or fuel retention. Excess fuel retained after consumption is sold at market prices. In addition to transport fees, our HPL System generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies.

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

market prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related financial derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains.

We also use financial derivatives to hedge prices on a portion of natural gas volumes retained as fees in our intrastate transportation and storage segment. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

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

Interstate transportation Revenue is primarily generated by fees earned from natural gas transportation services and operational gas sales.

Midstream Revenue is principally dependent upon the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines as well as the level of natural gas and NGL prices.

In addition to fee-based contracts for gathering, treating and processing, we also have percent of proceeds and keep-whole contracts, which are subject to market pricing. For percent of proceeds contracts (which accounted for approximately 11% of total processed volumes for the nine month periods ended September 30, 2010 and 2009, respectively), we retain a portion of the natural gas and NGLs processed as a fee. When natural gas and NGL pricing increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGL s decrease, so does the value of the portion we retain as a fee. For keep-whole contracts (which accounted for approximately 32% and 26% of total processed volumes for the nine month periods ended September 30, 2010 and 2009, respectively), we retain the difference between the price of NGLs and the cost of the gas to process it. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could be negative. In the event it is uneconomical to process this gas, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs.

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

Retail propane and other retail propane related operations Revenue is principally generated from the sale of propane and propane-related products and services.

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Results of Operations

Consolidated Results

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Revenues	$ 1,290,644	$ 1,129,596	$ 161,048	$ 4,430,331	$ 3,911,513	$ 518,818
Cost of products sold	777,411	678,148	99,263	2,773,133	2,263,280	509,853
Gross margin	513,233	451,448	61,785	1,657,198	1,648,233	8,965
Operating expenses	174,740	158,883	15,857	515,021	517,337	(2,316)
Depreciation and amortization	85,612	81,684	3,928	252,765	230,461	22,304
Selling, general and administrative	44,734	33,534	11,200	137,743	143,015	(5,272)
Operating income	208,147	177,347	30,800	751,669	757,420	(5,751)
Interest expense, net of interest capitalized	(101,241)	(101,503)	262	(309,217)	(284,228)	(24,989)
Equity in earnings of affiliates	595	9,581	(8,986)	10,848	11,751	(903)
Gains (losses) on disposal of assets	281	(1,088)	1,369	(198)	(1,333)	1,135
Gains (losses) on non-hedged interest rate derivatives	(11,963)	(18,241)	6,278	(11,963)	32,327	(44,290)
Allowance for equity funds used during construction	12,432	30	12,402	18,039	18,618	(579)
Impairment of investment in affiliate				(52,620)		(52,620)
Other, net	1,129	3,433	(2,304)	(3,731)	4,400	(8,131)
Income tax (expense) benefit	(1,993)	2,897	(4,890)	(12,486)	(8,594)	(3,892)
Net income	$ 107,387	$ 72,456	$ 34,931	$ 390,341	$ 530,361	$ (140,020)

See the detailed discussion of revenues, costs of products sold, gross margin, operating expenses, and depreciation and amortization by operating segment below.

Interest Expense. Interest expense increased $25.0 million for the nine months ended September 30, 2010 compared to the same period in the previous year principally due to our issuances of $1.0 billion in senior notes in April 2009 and Transwestern s issuance of $350.0 million of senior notes in December 2009. Interest expense is presented net of capitalized interest and allowance for debt funds used during construction, which totaled $7.1 million and $5.7 million for the three months ended September 30, 2010 and 2009, respectively, and $11.0 million and $15.5 million for the nine months ended September 30, 2010 and 2009, respectively.

Equity in Earnings of Affiliates. Equity in earnings of affiliates decreased $9.0 million for the three months ended September 30, 2010 compared to the same period in the previous year primarily due to our transfer of substantially all of our interest in MEP to ETE on May 26, 2010. For the nine months ended September 30, 2010, the impact of the MEP transfer is offset by increased earnings from MEP during the period prior to May 26, 2010 as a result of placing the Midcontinent Express pipeline into service in 2009.

Gains (Losses) on Non-Hedged Interest Rate Derivatives. For the three months ended September 30, 2010 and 2009, the losses on non-hedged interest rate derivatives reflect declines in the index rate during the periods. In addition, the losses on non-hedged interest rate derivatives were lower for the three months ended September 30, 2010 compared to the same period in the prior year due to a decrease in the notional amount of interest rate swaps outstanding during the period. As of September 30, 2010 and 2009, we had $400.0 million and $500.0 million, respectively, of total notional amount of interest rate swaps outstanding that were not designated as hedges for accounting purposes.

We did not have any non-hedged interest rate swaps outstanding during the first six months of 2010; therefore, the losses on non-hedged interest rate derivatives for the nine months ended September 30, 2010 reflect the losses recognized during the last three months of that period. For the nine months ended September 30, 2009, the gains on non-hedged interest rate swaps resulted from an increase in the index rate during the period.

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Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction (AFUDC) increased $12.4 million for the three months ended September 30, 2010, primarily due to construction on the Tiger pipeline. AFUDC on equity amounts recorded in property, plant and equipment (which excludes AFUDC gross-up) were $12.4 million and $20 thousand for the three months ended September 30, 2010 and 2009, respectively, and $17.9 million and $11.4 million for the nine months ended September 30, 2010 and 2009, respectively.

Impairment of Investment in Affiliate. In conjunction with the transfer of our interest in MEP, we recorded a non-cash charge of approximately $52.6 million during the nine months ended September 30, 2010 to reduce the carrying value of our interest to its estimated fair value.

Segment Operating Results

We evaluate segment performance based on operating income (either in total or by individual segment), 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.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 24, 2010.

Operating income (loss) by segment is as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Intrastate transportation and storage	$ 133,750	$ 109,781	$ 23,969	$ 395,772	$ 410,425	$ (14,653)
Interstate transportation	34,576	41,610	(7,034)	98,338	101,755	(3,417)
Midstream	52,793	43,414	9,379	154,990	96,603	58,387
Retail propane and other retail propane related	(13,053)	(16,550)	3,497	107,285	152,079	(44,794)
All other	(2,601)	(3,021)	420	(3,963)	(4,803)	840
Selling, general and administrative expenses not allocated to segments	2,682	2,113	569	(753)	1,361	(2,114)
Operating income	$ 208,147	$ 177,347	$ 30,800	$ 751,669	$ 757,420	$ (5,751)

Selling, General and Administrative Expenses Not Allocated to Segments. Selling, general and administrative expenses are allocated monthly to the Operating Companies using the Modified Massachusetts Formula Calculation (MMFC). The expenses subject to allocation are based on estimated amounts and take into consideration our actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month, which results in over or under allocation of these costs due to timing differences.

Intrastate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Natural gas MMBtu/d transported	13,250,836	11,111,011	2,139,825	12,132,099	12,769,022	(636,923)
Natural gas MMBtu/d sold	1,812,938	886,463	926,475	1,642,910	879,861	763,049
Revenues	$ 898,994	$ 466,713	$ 432,281	$ 2,614,373	$ 1,589,298	$ 1,025,075
Cost of products sold	660,107	278,868	381,239	1,930,798	895,433	1,035,365
Gross margin	238,887	187,845	51,042	683,575	693,865	(10,290)
Operating expenses	56,167	45,053	11,114	145,497	155,461	(9,964)
Depreciation and amortization	29,340	27,188	2,152	87,484	78,080	9,404
Selling, general and administrative	19,630	5,823	13,807	54,822	49,899	4,923
Segment operating income	$ 133,750	$ 109,781	$ 23,969	$ 395,772	$ 410,425	$ (14,653)

Volumes. For the three months ended September 30, 2010 compared to the three months ended September 30, 2009, the increase in volumes transported on our intrastate transportation systems resulted from increased demand for transportation capacity primarily due to increased production by our customers in areas where our assets are located due to a more favorable natural gas price environment and basis differentials between the West and East Texas market hubs. The average spot price difference between these locations was $0.25/MMBtu during the three months ended September 30, 2010 compared to $0.06/MMBtu during the three months ended September 30, 2009.

For the nine months ended September 30, 2010, the decrease in volumes transported resulted from less production by our customers in the areas where our assets are located and from the less favorable basis differentials between the West and East Texas market hubs that occurred during the first six months of 2010. The average spot price differential between these locations was $0.14/MMBtu during the nine months ended September 30, 2010 compared to $0.38/MMBtu during the nine months ended September 30, 2009.

Natural gas sold volumes include operational sales of retention natural gas in excess of consumption, natural gas purchased and sold on our system, and natural gas sales as a result of withdrawal from the Bammel storage facility. For both the three and nine months ended September 30, 2010, the increase in natural gas sold was a result of more withdrawals out of our Bammel storage facility as well as additional activity by our commercial group to optimize our transportation pipeline assets.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Transportation fees	$ 152,223	$ 142,144	$ 10,079	$ 447,775	$ 496,248	$ (48,473)
Natural gas sales and other	27,504	27,411	93	83,464	65,361	18,103
Retained fuel revenues	35,930	29,244	6,686	109,017	99,973	9,044
Storage margin, including fees	23,230	(10,954)	34,184	43,319	32,283	11,036
Total gross margin	$ 238,887	$ 187,845	$ 51,042	$ 683,575	$ 693,865	$ (10,290)

For the three months ended September 30, 2010, intrastate transportation and storage gross margin increased compared to the same period in the prior year primarily due to the following factors:

For the three months ended September 30, 2010, the increase in transportation fees of $10.1 million was mainly due to the volume increases discussed above.

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Retention fuel revenue increased due to more favorable pricing despite retention volumes being down slightly for the three months ended September 30, 2010 as compared to the same period last year. Our average retention price for physical gas we retained during the three months ended September 30, 2010 was $4.09/MMBtu compared to $3.16/MMBtu for the three months ended September 30, 2009. Retained fuel revenues include gross volumes retained as a fee. The cost of consuming fuel to run our compressors is included in operating expenses.

Margin from the sales of natural gas and other did not change significantly during the three months ended September 30, 2010 as compared to the three months ended September 30, 2009. The margin from the sales of natural gas and other include natural gas for sale, derivatives used to hedge transportation activity and net retained fuel. Excluding storage derivatives, we recorded unrealized gains of $0.6 million and $7.6 million in the three months ended September 30, 2010 and September 30, 2009, respectively.

For the nine months ended September 30, 2010, our margin decreased as compared to the nine months ended September 30, 2009 due to the net impact of the following factors:

Volumes on our transportation pipelines decreased for the nine months ended September 30, 2010, as discussed above, resulting in a decrease in transportation fees of $48.5 million.

Changes in margin from natural gas sales and other activity increased primarily due to more favorable margins on gas sales and favorable impacts from system optimization activities including the settlement of our retention gas hedges. The margin from the sales of natural gas and other include natural gas for sale, derivatives used to hedge transportation activity and net retained fuel. Excluding derivatives related to storage, for the nine months ended September 30, 2010, we recognized unrealized losses of $16.3 million compared to unrealized gains of $10.8 million for the nine months ended September 30, 2009.

Retention fuel revenue increased due to more favorable pricing, as retention volumes were down for the nine months ended September 30, 2010 compared to the same period last year. Our average retention price for physical gas we retained during the nine months ended September 30, 2010 was $4.33/MMBtu compared to $3.25/MMBtu for the same period last year. Retained fuel revenues include gross volumes retained as a fee. The cost of consuming fuel to run our compressors is included in operating expenses.

Storage margin was comprised of the following:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Withdrawals from storage natural gas inventory (MMBtu)	7,459,977	300,786	7,159,191	35,347,967	11,555,189	23,792,778
Margin on physical sales	$ 2,397	$ (472)	$ 2,869	$ 68,049	$ (11,488)	$ 79,537
Fair value adjustments	(7,908)	(14,778)	6,870	(70,162)	(44,337)	(25,825)
Settlements of financial derivatives	(8,479)	10,012	(18,491)	(17,408)	169,726	(187,134)
Unrealized gains (losses) on derivatives	27,867	(17,788)	45,655	33,161	(107,506)	140,667
Net impact of natural gas inventory transactions	13,877	(23,026)	36,903	13,640	6,395	7,245
Revenues from fee-based storage	9,286	10,764	(1,478)	30,913	28,869	2,044
Other costs	67	1,308	(1,241)	(1,234)	(2,981)	1,747
Total storage margin	$ 23,230	$ (10,954)	$ 34,184	$ 43,319	$ 32,283	$ 11,036

In addition to fee based contracts, our storage margin is also impacted by the price variance between the carrying amount of our inventory and the locked-in sales price of our financial derivatives. We apply fair value hedge accounting to the natural gas we purchase for storage and adjust the carrying amount of our inventory to the spot price at the end of each period. These inventory fair value adjustments are offset by a portion of the unrealized gains or losses on the related financial derivative. These changes in value occur until the settlement of the derivative or the actual withdrawal of the inventory, when the earnings are realized. The unrealized gains and losses that we recognize represent the change in the spread between the spot price and the forward price. This spread can widen or narrow, thereby creating unrealized losses or gains, until ultimately converging when the financial contract settles.

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For both the three and nine months ended September 30, 2010, the spread between the spot price and the forward price has narrowed relative to the prior year, resulting in a favorable impact to our storage margin compared to the same periods in the prior year.

Operating Expenses. For the three months ended September 30, 2010, intrastate operating expenses increased principally due to increases in maintenance expense of $5.8 million, including $4.1 million for repairs on our Oasis pipeline, and an increase in ad valorem expenses of $5.1 million.

For the nine months ended September 30, 2010, operating expenses decreased by approximately $10.0 million primarily due to a decrease in consumption expense of $13.2 million, lower electricity expense of $3.9 million, and lower compressor maintenance expense of $1.1 million as compared to the nine months ended September 30, 2009. These decreases were offset by increases in pipeline maintenance expense of $6.2 million and ad valorem expenses of $1.5 million as compared to the nine months ended September 30, 2009.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased during the three and nine months ended September 30, 2010 compared to the prior periods primarily due to the completion of pipeline projects in connection with the continued expansion of our pipeline system.

Selling, General and Administrative. Intrastate selling, general and administrative expenses increased for the three and nine months ended September 30, 2010 as a result of an increase in employee related costs (including allocated overhead expenses) of $17.3 million and $18.4 million, respectively. This increase was offset by a decrease in professional fees of approximately $3.8 million and $12.8 million for the three and nine months ended September 30, 2009, respectively.

Interstate Transportation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Natural gas MMBtu/d transported	1,807,012	1,688,388	118,624	1,625,469	1,706,199	(80,730)
Natural gas MMBtu/d sold	24,282	19,060	5,222	23,027	19,481	3,546
Revenues	$ 74,659	$ 71,415	$ 3,244	$ 213,007	$ 203,349	$ 9,658
Operating expenses	19,886	13,718	6,168	56,147	46,427	9,720
Depreciation and amortization	12,643	12,521	122	37,856	36,017	1,839
Selling, general and administrative	7,554	3,566	3,988	20,666	19,150	1,516
Segment operating income	$ 34,576	$ 41,610	$ (7,034)	$ 98,338	$ 101,755	$ (3,417)

The interstate transportation segment data presented above does not include our interstate pipeline joint ventures, for which we reflect our proportionate share of income within Equity in earnings of affiliates below operating income in our condensed consolidated statement of operations. We recorded equity in earnings related to MEP of $7.0 million for the three months ended September 30, 2009 and $8.9 million and $7.7 million for the nine months ended September 30, 2010 and 2009, respectively, related to our 50% joint venture investment. As discussed above, we transferred substantially all of our interest in MEP to ETE on May 26, 2010.

Volumes. Transported volumes increased during the three months ended September 30, 2010 primarily due to favorable market conditions for transporting natural gas principally from the San Juan Basin to East delivery points. For the nine months ended September 30, 2010, transported volumes decreased as a result of less favorable market conditions principally during the first six months of 2010.

Revenues. For the three months ended September 30, 2010, revenues increased by approximately $3.2 million compared to the three months ended September 30, 2009 primarily as a result of favorable market conditions for transporting natural gas from the San Juan to East delivery points during the period.

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For the nine months ended September 30, 2010, revenues increased by approximately $9.7 million compared to the prior period primarily due to increases in margin related to our operational gas sales, in addition to the completion of the Phoenix project in February 2009. This increase was partially offset by a decrease in transportation revenues due to lower transported volumes compared to the nine months ended September 30, 2009.

Operating Expenses. Operating expenses increased during the three and nine months ended September 30, 2010 primarily due to increases in ad valorem taxes resulting from increased property values related to the Phoenix pipeline.

Depreciation and Amortization. Depreciation and amortization expense increased during the nine months ended September 30, 2010, primarily due to incremental depreciation associated with the completion of the Phoenix pipeline expansion that was completed in February 2009.

Selling, General and Administrative. Selling, general and administrative expenses increased during the three and nine months ended September 30, 2010 primarily due to higher employee-related costs and allocated overhead.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Natural gas sold (MMBtu/d)	1,553,671	1,021,963	531,708	1,370,293	1,009,547	360,746
NGLs produced (Bbls/d)	53,004	46,628	6,376	50,836	47,143	3,693
Revenues	$ 875,084	$ 573,066	$ 302,018	$ 2,429,649	$ 1,750,466	$ 679,183
Cost of products sold	775,769	480,746	295,023	2,138,125	1,510,030	628,095
Gross margin	99,315	92,320	6,995	291,524	240,436	51,088
Operating expenses	19,734	16,054	3,680	56,597	50,858	5,739
Depreciation and amortization	21,592	18,091	3,501	62,209	51,792	10,417
Selling, general and administrative	5,196	14,761	(9,565)	17,728	41,183	(23,455)
Segment operating income	$ 52,793	$ 43,414	$ 9,379	$ 154,990	$ 96,603	$ 58,387

Volumes. NGL production increased during the three and nine months ended September 30, 2010 primarily due to increased inlet volumes at our Godley plant as a result of more production by our customers in the North Texas area in addition to favorable processing conditions.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Gathering and processing fee-based revenues	$ 55,840	$ 41,554	$ 14,286	$ 165,718	$ 135,438	$ 30,280
Non fee-based contracts and processing	48,799	41,229	7,570	146,295	90,599	55,696
Other	(5,324)	9,537	(14,861)	(20,489)	14,399	(34,888)
Total gross margin	$ 99,315	$ 92,320	$ 6,995	$ 291,524	$ 240,436	$ 51,088

Gathering and processing fee-based revenues increased between the periods due to the following:

For the three months ended September 30, 2010, increased volumes in our North Texas system resulted in increased fee-based revenues of $7.8 million as compared with the same period last year. Additionally, increased volumes resulting from our recent acquisitions and other growth capital expenditures located in Louisiana provided an increase in our margin of $6.9 million. There was also a slight decline in fee-based revenues on our South East Texas system for the three months ended September 30, 2010 as compared to the three months ended September 30, 2009.

For the nine months ended September 30, 2010, increased volumes in our North Texas system resulted in increased fee-based revenues of $18.2 million as compared with the same period last year. Additionally, increased volumes resulting from our recent acquisitions and other growth capital expenditures located in Louisiana provided an increase of $19.1 million in our fee-based margin. A decrease in fee-based volumes on our Southeast Texas system offset the above noted increases for the nine months ended September 30, 2010 as compared to the nine months ended September 30, 2009.

Non fee-based contracts and processing margins increased between the periods due to the following:

- For the three months ended September 30, 2010, our non fee-based gross margins increased $7.6 million primarily due to higher processing volumes at our Godley plant and more favorable NGL prices. The composite NGL price increased to $0.91 per gallon for the three months ended September 30, 2010 from $0.79 per gallon during the three months ended September 30, 2009.

- For the nine months ended September 30, 2010, non fee-based gross margin increased primarily due to higher processing volumes at our Godley plant and more favorable NGL prices. The composite NGL price increased to $1.00 per gallon for the nine months ended September 30, 2010 from $0.69 per gallon in the prior comparable period. The increase in NGL volumes, as well as more favorable pricing, resulted in an increase in our non fee-based margin of $55.7 million.

Other midstream gross margin reflects the following:

- For the three months ended September 30, 2010, the decrease in other midstream gross margin resulted from losses of $5.3 million from marketing activities due to less favorable market conditions compared to the three months ended September 30, 2009. During the three months ended September 30, 2010, our midstream segment realized derivative gains that had previously been recorded through mark-to-market adjustments. Therefore, the costs being hedged during the period ended September 30, 2010 did not have an offset as the unrealized gains were recognized in a prior period. We recorded unrealized gains of $0.1 million during the three months ended September 30, 2010 compared to unrealized gains of $11.2 million during the three months ended September 30, 2009.

- For the nine months ended September 30, 2010, the decrease in other midstream gross margin was due to losses of $20.5 million from marketing activities due to less favorable market conditions compared to the nine months ended September 30, 2009. Additionally, marketing activities recorded unrealized gains in the prior year associated with physical transactions that occurred during the nine months ended September 30, 2010 so that the physical transaction being hedged did not have the offset of the financial derivative used to hedge it during the same period. We recorded unrealized losses of $11.6 million during the nine months ended September 30, 2010 compared to unrealized gains of $5.8 million during the nine months ended September 30, 2009.

Operating Expenses. Operating expenses increased between the periods primarily as a result of increases in maintenance costs and other various operating costs as a result of the increased activity noted above.

Depreciation and Amortization. Midstream depreciation and amortization expense increased between the periods primarily due to incremental depreciation from the continued expansion of our Louisiana assets.

Selling, General and Administrative. For the three months ended September 30, 2010, midstream selling, general and administrative expenses decreased compared to the three months ended September 30, 2009 primarily due to a decrease in professional fees of $11.1 million offset by a net increase in all other general and administrative costs of $1.6 million primarily due to increased employee-related costs between the periods.

For the nine months ended September 30, 2010, midstream selling, general and administrative expenses decreased compared to the nine months ended September 30, 2009 primarily due to a decrease in professional fees.

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Retail Propane and Other Retail Propane Related

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Retail propane gallons (in thousands)	85,722	87,569	(1,847)	388,306	398,202	(9,896)
Retail propane revenues	$ 183,786	$ 162,224	$ 21,562	$ 914,372	$ 829,901	$ 84,471
Other retail propane related revenues	22,047	22,063	(16)	72,742	72,570	172
Retail propane cost of products sold	104,533	80,232	24,301	519,796	378,524	141,272
Other retail propane related cost of products sold	5,377	4,796	581	15,004	14,495	509
Gross margin	95,923	99,259	(3,336)	452,314	509,452	(57,138)
Operating expenses	75,990	81,298	(5,308)	247,692	259,768	(12,076)
Depreciation and amortization	20,609	23,031	(2,422)	60,994	63,477	(2,483)
Selling, general and administrative	12,377	11,480	897	36,343	34,128	2,215
Segment operating income	$ (13,053)	$ (16,550)	$ 3,497	$ 107,285	$ 152,079	$ (44,794)

Volumes. For the three and nine months ended September 30, 2010, retail propane volumes sold were slightly lower than volumes sold in the same periods in the prior year. We use information published by the National Oceanic and Atmospheric Administration (NOAA) to gather heating degree day data and compare with normal which we define as the prior ten year average. For the three months ended September 30, 2010 and 2009, average temperatures were warmer than normal by 10.6% and 10.0%, respectively. For the nine months ended September 30, 2010, temperatures in our operating areas were approximately 3.6% colder than normal as compared to weather which was approximately 1.6% colder than normal during the same period in 2009. The timing and geographic distribution of temperature patterns, mainly an early and abrupt end to the 2009-2010 heating season in the eastern United States, coupled with continued customer conservation and the economic recession slowed certain normal seasonal deliveries in the late spring and summer of 2010.

Gross Margin. For the three months ended September 30, 2010, gross margin decreased $3.3 million primarily due to the slight decline in volumes as described above and unrealized gains of $1.5 million recorded during the three months ended September 30, 2009. Excluding the impact of the unrealized gains recorded during the 2009 three month period, the average gross margin per gallon sold was relatively consistent period over period.

For the nine months ended September 30, 2010, gross margin decreased $57.1 million primarily due to the impact of the mark-to-market accounting of financial instruments in 2009 and a slight decrease due to the decline in volumes during the current period. Prior to April 2009, our financial instruments used to hedge our customer prebuy programs were not designated as cash flow hedges for accounting purposes, and changes in market value were recorded in cost of products sold in the condensed consolidated statements of operations. The propane margins were positively impacted in the 2009 period by the recognition of unrealized gains of $44.7 million during the period ended September 30, 2009 on these contracts. In comparison, the impact of the remaining contracts under mark-to-market accounting was unrealized losses for the nine month period ended September 30, 2010 of $3.3 million. Excluding the impact of the mark-to-market accounting during 2009, the average gross margin per gallon sold was relatively consistent period over period.

Operating Expenses. Operating expenses decreased during the three and nine months ended September 30, 2010 primarily due to decreases of $3.7 million and $14.5 million, respectively, in employee wages and benefits as a result of lower seasonal staffing needs and performance-based bonus accruals. Operating expenses also reflected decreases of $2.2 million between the three month periods due to a reduction in net business insurance reserves and claims for the current quarter and $1.7 million between the nine month periods due to a reduction in our reserve for bad debts and customer related expenses as our accounts receivable collections improved over the prior year. These decreases were partially offset by slight increases in other general operating expenses primarily in our vehicle fuel expenses due to the increase in fuel costs between periods.

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Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses between comparable periods was primarily due to increased allocated overhead expenses of $1.1 million and $2.2 million for the three and nine month periods, respectively.

Liquidity and Capital Resources

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

We currently believe that our business has the following future capital requirements:

- growth capital expenditures for our midstream and intrastate transportation and storage segments, primarily for the construction of new pipelines and compression, for which we expect to spend between $75 million and $125 million during the last three months of 2010 and between $100 million and $200 million in 2011;

- growth capital expenditures for our interstate transportation segment, excluding capital contributions to our joint ventures as discussed below, for the construction of new pipelines for which we expect to spend between $200 million and $270 million during the last three months of 2010 and between $180 million and $225 million in 2011;

- growth capital expenditures for our retail propane segment of between $10 million and $20 million during the last three months of 2010 and between $25 million and $35 million in 2011; and

- maintenance capital expenditures of between $25 million and $40 million during the last three months of 2010 and between $120 million and $140 million in 2011, which include (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; and (iii) capital expenditures for our propane operations to extend the useful lives of our existing propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet.

In addition, we may enter into acquisitions, including the potential acquisition of new pipeline systems and propane operations.

We generally fund our capital requirements with cash flows from operating activities and, to the extent that they exceed cash flows from operating activities, with proceeds of borrowings under existing credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof.

We raised approximately $423.6 million in net proceeds from our Common Unit offering in January 2010 and $489.4 million in net proceeds from our Common Unit offering in August 2010. In addition, we raised $174.1 million in net proceeds during the nine months ended September 30, 2010 under our Equity Distribution Agreement, as described in Note 11 to our condensed consolidated financial statements. As of September 30, 2010, in addition to approximately $77.7 million of cash on hand, we had available capacity under our revolving credit facility (the ETP Credit Facility) of approximately $1.98 billion. Based on our current estimates, we expect to utilize these resources, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2011; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Cash Flows

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These factors 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.

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Operating Activities

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

Nine months ended September 30, 2010 compared to nine months ended September 30, 2009. Cash provided by operating activities during 2010 was $1.1 billion as compared to $796.0 million for 2009. Net income was $390.3 million and $530.4 million for 2010 and 2009, respectively. The difference between net income and the net cash provided by operating activities for the nine months ended September 30, 2010 and 2009 primarily consisted of non-cash items totaling $324.0 million and $249.1 million, respectively, and changes in operating assets and liabilities of $344.7 million and $24.3 million, respectively. For the nine months ended September 30, 2010, the difference between net income and the net cash provided by operating activities also included interest rate swap termination proceeds of $26.5 million and distributions received from our affiliates that exceeded our equity in earnings by $20.8 million.

The non-cash activity in 2010 and 2009 consisted primarily of depreciation and amortization of $252.8 million and $230.5 million, respectively. In addition, non-cash compensation expense was $22.4 million and $21.9 million for 2010 and 2009, respectively. The nine months ended September 30, 2010 also reflect a non-cash impairment at $52.6 million on our investment in MEP prior to our transfer of substantially all of our investment to Regency on May 26, 2010. These amounts are partially offset by the allowance for equity funds used during construction of $18.0 million and $18.6 million for 2010 and 2009, respectively.

Cash paid for interest, net of interest capitalized, was $345.5 million and $288.5 million for the nine months ended September 30, 2010 and 2009, respectively.

Investing Activities

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

Nine months ended September 30, 2010 compared to nine months ended September 30, 2009. Cash used in investing activities during 2010 was $1.17 billion as compared to $1.23 billion for 2009. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2010 were $1.04 billion including changes in accruals of $37.0 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2009 of $703.5 million, including changes in accruals of $98.3 million. In addition, in 2010 we paid cash for acquisitions of $156.4 million and made advances to our joint ventures of $6.0 million. We paid cash for acquisitions of $6.2 million and made advances to our joint ventures of $534.5 million during 2009.

Growth capital expenditures for 2010, before changes in accruals, were $265.9 million for our midstream and intrastate transportation and storage segments, $711.6 million for our interstate transportation segment, and $26.1 million for our retail propane segment and all other. We also incurred $70.3 million of maintenance capital expenditures, of which $31.8 million related to our midstream and intrastate transportation and storage segments, $16.1 million related to our interstate segment and $22.4 million related to our retail propane segment and all other. Growth capital expenditures for our interstate transportation segment for 2010 are primarily related to the Tiger pipeline which is expected to be placed in service in December 2010.

Growth capital expenditures for 2009, before changes in accruals, were $394.5 million for our midstream and intrastate transportation and storage segments, $107.7 million for our interstate transportation segment, and $31.3 million for our

retail propane segment and all other. We also incurred $71.8 million in maintenance expenditures, of which $45.4 million related to our midstream and intrastate transportation and storage segments, $8.9 million related to our interstate segment and $17.4 million related to our retail propane segment.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, as discussed below under Financing and Sources of Liquidity, 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.

Nine months ended September 30, 2010 compared to nine months ended September 30, 2009. Cash provided by financing activities during 2010 was $80.2 million as compared $387.9 million for 2009. In 2010, we received $1.09 billion in net proceeds from Common Unit offerings, including $174.1 million under our Equity Distribution Agreement, as compared to net proceeds from Common Unit offerings of $578.9 million in 2009 (see Note 11 to our condensed consolidated financial statements). Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, to fund capital contributions to joint ventures, as well as for general partnership purposes. During 2010, we had a net decrease in our debt level of $197.7 million as compared to a net increase of $519.0 million for 2009. In addition, we paid distributions of $794.8 million to our partners in 2010 as compared to $705.7 million in 2009.

Financing and Sources of Liquidity

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2010	December 31, 2009
ETP Senior Notes	$ 5,050,000	$ 5,050,000
Transwestern Senior Unsecured Notes	870,000	870,000
HOLP Senior Secured Notes	105,127	140,512
Revolving credit facilities		160,000
Other long-term debt	8,306	10,122
Unamortized discounts	(12,268)	(12,829)
Fair value adjustments related to interest rate swaps	18,663	
Total debt	$ 6,039,828	$ 6,217,805

The terms of our consolidated indebtedness are described in more detail in our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 24, 2010.

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity) under the credit agreement that governs the ETP Credit Facility. The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest, at our option, at a Eurodollar rate plus an applicable margin or a base rate. The base rate used to calculate interest on base rate loans will be calculated using the greater of a prime rate or a federal funds effective rate plus 0.50%. The applicable margin for Eurodollar loans ranges from 0.30% to 0.70% based upon ETP s credit rating and is currently 0.55% (0.60% if facility usage exceeds 50%). The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

As of September 30, 2010, there were no outstanding borrowings under the ETP Credit Facility. Taking into account letters of credit of approximately $22.4 million, the amount available for future borrowings was $1.98 billion.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the HOLP Credit Facility) available through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP s subsidiaries secure the HOLP Credit Facility. At September 30, 2010, there was no outstanding balance in revolving credit loans and outstanding letters of credit of $0.5 million. The amount available for borrowing as of September 30, 2010 was $74.5 million.

Other

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the MEP Facility), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions. Although we transferred substantially all of our interest in MEP on May 26, 2010 in connection with the Regency Transactions, we will continue to guarantee 50% of MEP s obligations under this facility through the maturity of the facility in February 2011. Regency has agreed to indemnify us for any costs related to the guaranty of payments under this facility.

Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of September 30, 2010, MEP had $82.2 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP s outstanding borrowings and letters of credit were $41.1 million and $16.6 million, respectively, as of September 30, 2010. The weighted average interest rate on the total amount outstanding as of September 30, 2010 was 0.9%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the FEP Facility). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of September 30, 2010, FEP had $847.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our 50% guarantee of FEP s outstanding borrowings was $423.5 million as of September 30, 2010. The weighted average interest rate on the total amount outstanding as of September 30, 2010 was 3.3%.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at September 30, 2010.

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Cash Distributions

Under our partnership agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash (as defined 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.

Distributions paid by us are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distributions Per Common Unit
December 31, 2009	February 8, 2010	February 15, 2010	$0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375
June 30, 2010	August 9, 2010	August 16, 2010	0.89375

On October 28, 2010, ETP declared a cash distribution for the three months ended September 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on November 15, 2010 to Unitholders of record at the close of business on November 8, 2010.

The total amounts of distributions declared during the nine months ended September 30, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Nine Months Ended September 30,	
	2010	2009
Limited Partners:		
Common Units	$ 503,582	$ 460,132
Class E Units	9,363	9,363
General Partner Interest	14,634	14,626
Incentive Distribution Rights	279,823	256,530
Total distributions declared	$ 807,402	$ 740,651

New Accounting Standards and Critical Accounting Policies

Disclosure of our critical accounting policies and the impacts of new accounting standards is included in our Annual Report on Form 10-K for the year ended December 31, 2009.

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, 2009, in addition to the interim unaudited condensed consolidated financial statements, 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, 2009. Since December 31, 2009, there have been no material changes to our primary market risk exposures or how those exposures are managed, except that we have begun to periodically enter into interest rate swaptions when our targeted benchmark interest rates for anticipated debt issuances are not attainable at the time in the interest rate swap market. Swaptions enable counterparties to exercise options to enter into interest rate swaps with us in exchange for premiums. Our swaption activity is further discussed in Note 14 to our condensed consolidated financial statements.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July, 21,

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2010 and requires the Commodities Futures Trading Commission (The CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure its existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of September 30, 2010 and December 31, 2009, 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 and gallons for propane. Dollar amounts are presented in thousands.

	September 30, 2010			December 31, 2009		
	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						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(33,870,000)	$ (205)	$ 1,621	72,325,000	$ 24,554	$ 491
Swing Swaps IFERC	11,735,000	(938)	151	(38,935,000)	1,718	2,142
Fixed Swaps/Futures	(250,000)	2,168	80	4,852,500	9,949	3,126
Options Puts	440,000	13,976	1,748	2,640,000	837	447
Options Calls	(3,440,000)	(8,567)	179	(2,640,000)	(819)	314
Propane:						
Forwards/Swaps				6,090,000	3,348	785
Fair Value Hedging Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(10,060,000)	(307)	118	(22,625,000)	(4,178)	2
Fixed Swaps/Futures	(20,160,000)	17,739	8,504	(27,300,000)	(13,285)	15,669
Cash Flow Hedging Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(4,445,000)	(640)	25	(13,225,000)	(1,640)	81
Fixed Swaps/Futures	(7,265,000)	17,140	2,871	(22,800,000)	(4,464)	13,197
Options Puts	22,680,000	15,049	5,628			
Options Calls	(22,680,000)	6,991	856			
Propane:						
Forwards/Swaps	58,086,000	5,685	6,901	20,538,000	8,443	2,609

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information, broker quotes 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

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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 September 30, 2010, we had no variable rate debt outstanding. We have interest rate swaps outstanding as of September 30, 2010 with total notional amounts of $400.0 million that are not designated as hedges for accounting purposes. These forward starting swaps begin in August 2012 and we will pay a weighted average fixed rate of 3.64% and receive a floating rate. A hypothetical change of 100 basis points in interest rates for interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings of approximately $34.0 million.

Credit Risk

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

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

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 condensed consolidated balance sheet and recognized in net income or other comprehensive income.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Securities Exchange Act of 1934 (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 September 30, 2010 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended September 30, 2010 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, 2009 and Note 13 Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Condensed Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2010.

ITEM 1A. RISK FACTORS

For information regarding risks, uncertainties and assumptions, see Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2009. Except as disclosed below, there are no material changes from risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2009 and our Quarterly Report on Form 10-Q for the quarter ended June 30, 2010.

Risks Related to Our Business

Our General Partner is owned by ETE, which also owns the general partner of Regency Energy Partners LP. This may result in conflicts of interest.

ETE owns our General Partner and as a result controls us. ETE also owns the general partner of Regency Energy Partners LP, or Regency, a publicly traded partnership with which we compete in the natural gas gathering, processing and transportation business. The directors and officers of our General Partner and its affiliates have fiduciary duties to manage our general partner in a manner that is beneficial to ETE, the sole owner of our General Partner. At the same time, our general partner has fiduciary duties to manage us in a manner that is beneficial to our Unitholders. Therefore, our General Partner s duties to us may conflict with the duties of its officers and directors to ETE as its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ETE, Regency or their owners or affiliates over the interest of our Unitholders.

Such conflicts may arise from, among others, the following:

- Decisions by our General Partner regarding the amount and timing of our cash expenditures, borrowings and issuances of additional limited partnership units or other securities can affect the amount of incentive compensation distributions we make to ETE as the sole owner of our General Partner.

- ETE and Regency and their affiliates may engage in substantial competition with us.

- Neither our partnership agreement nor any other agreement requires ETE or its affiliates, including Regency, to pursue a business strategy that favors us. The directors and officers of the general partners of ETE and Regency have a fiduciary duty to make decisions in the best interest of their members, limited partners and unitholders, which may be contrary to our best interests.

- Our General Partner is allowed to take into account the interests of other parties, such as ETE and Regency and their affiliates, which has the effect of limiting its fiduciary duties to our Unitholders.

- Some of the directors and officers of ETE who provide advice to us also may devote significant time to the business of ETE and Regency and their affiliates and will be compensated by them for their services.

Our partnership agreement limits the liability and reduces the fiduciary duties of our General Partner while also restricting the remedies available to our Unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty.

Our General Partner determines the amount and timing of asset purchases and sales and other acquisitions, operating expenditures, capital expenditures, borrowings, repayments of debt, issuances of equity and debt securities and cash reserves, each of which can affect the amount of cash available for distribution to our Unitholders.

Our General Partner determines which costs, including allocated overhead costs, incurred by it and its affiliates are reimbursable by us.

Our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

Specifically, certain conflicts may arise as a result of our pursuing acquisitions or development opportunities that may also be advantageous to Regency. If we are limited in our ability to pursue such opportunities, we may not realize any or all of the commercial value of such opportunities. In addition, if Regency is allowed access to our information concerning any such opportunity and Regency uses this information to pursue the opportunity to our detriment, we may not realize any of the commercial value of this opportunity. In either of these situations, our business, results of operations and the amount of our distributions to our Unitholders may be adversely affected. Although we, ETE and Regency have adopted a policy to address these conflicts and to limit the commercially sensitive information that we furnish to ETE, Regency and their affiliates, we cannot assure you that such conflicts will not occur.

Tax Risks to Common Unitholders

The sale or exchange of 50% or more of our capital and profit interests during any twelve month period will result in the termination of our partnership for federal income tax purposes.

We will be considered terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all Unitholders which would require us to file two tax returns for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a Unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such Unitholder s taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes, and would be required to make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred.

In September 2010, Enterprise GP Holdings L.P., which holds approximately 17.6% of the outstanding Common Units of ETE and an approximate 40.6% interest in ETE s general partner, announced an agreement to merge into Enterprise Products Partners L.P. For federal income tax purposes, this transaction will be treated as a change of ownership of the interests in ETE and its general partner owned by Enterprise GP Holdings L.P. As a result, if and when this transaction is consummated, it will increase the likelihood that a termination of our partnership for federal income tax purposes may occur at that time or at any time during the twelve-month period following the consummation of the transaction, resulting in a closing of our taxable year, as discussed above.

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

(a) *Unregistered Sales of Equity Securities.* Not applicable.

(b) *Use of Proceeds.* Not applicable.

(c) *Issuer Purchases of Equity Securities.* The following table discloses purchases of our Common Units made by us or on our behalf for the three months ended September 30, 2010.

Period	Total Number of Units Purchased (1)	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Yet Be Purchased Under the Plans or Programs
July 1 July 31	266	$ 45.54	N/A	N/A
August 1 August 31	2,393	50.43	N/A	N/A
September 1 September 30	533	46.65	N/A	N/A
Total	3,192	$ 49.43	N/A	N/A

(1) Pursuant to the terms of our equity incentive plans, to the extent the Partnership is required to withhold federal, state, local or foreign taxes in connection with any grant of an award, the issuance of Common Units upon the vesting of an award, or payment made to a plan participant, it is a condition to the receipt of such payment that the plan participant make arrangements satisfactory to the Partnership for the payment of taxes. A plan participant may relinquish a portion of the Common Units to which the participant is entitled in connection with the issuance of Common Units upon vesting of an award as payment for such taxes. During the three months ended September 30, 2010, certain of the participants in the 2004 Unit Plan and the 2008 Long-Term Incentive Plan elected to have a portion of the Common Units to which they were entitled upon vesting of restricted units withheld by the Partnership to satisfy the Partnership s tax withholding obligations. None of the Common Units delivered to recipients of unit awards upon vesting were purchased by the Partnership through a publicly announced open-market plan or program.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

(a) Exhibits

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

	Exhibit Number	Description
(8)	2.1	Redemption and Exchange Agreement, dated May 10, 2010, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(1)	3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) dated as of July 28, 2009.
(2)	3.2	Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(3)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.

(4)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(6)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.

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	Exhibit Number	Description
(6)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(5)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(7)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(7)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(10)	3.7	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C.
(9)	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.
(9)	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
(9)	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Condensed Consolidated Balance Sheets as of September 30, 2010 and December 31, 2009; (ii) our Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2010 and 2009; (iii) our Condensed Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2010 and 2009; (iv) our Condensed Consolidated Statement of Partners Capital for the nine months ended September 30, 2010; (v) our Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2010 and 2009; and (vi) the notes to our Condensed Consolidated Financial Statements, tagged as blocks of text.

* Filed herewith.
** Furnished herewith.

(1) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K filed July 29, 2009.

(2) Incorporated by reference to the same numbered Exhibit to the Registrant s Registration Statement on Form S-1/A, File No. 333-04018, filed June 21, 1996.

(3) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.

(4) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2002.

(5) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2002.

(6) Incorporated by reference as the same numbered exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.

(7) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2007.

(8) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K/A filed June 2, 2010.

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(9) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended March 31, 2010.

(10) Incorporated by reference to Exhibit 3.1 to the Registrant s Form 8-K filed August 10, 2010.

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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: November 9, 2010

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