UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended September 30, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from ______ to ______

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 or 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 ☒ 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 (check one).

Large accelerated filer	☒	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 ☒

At November 7, 2008, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 152,022,145 Common Units

Table of Contents

FORM 10-Q

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

Table of Contents

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. ("Energy Transfer Partners" 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 within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "continue," "estimate," "forecast," "may," "will," or similar expressions help identify forward-looking statements. Although the 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 every objective will be reached.

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, difficult to predict, and beyond management's control. For additional discussion of risks, uncertainties and assumptions, see "Part II Other Information – Item 1A, Risk Factors" in this Quarterly Report on Form 10-Q as well as the Partnership's Report on Form 10-K as of August 31, 2007 filed with the Securities and Exchange Commission ("SEC") on October 30, 2007.

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
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"). 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.
Mcf	thousand cubic feet
MMBtu	million British thermal unit
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.

Table of Contents

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, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 526,074	$ 56,467
Marketable securities	11,038	3,002
Accounts receivable, net of allowance for doubtful accounts	598,812	822,027
Accounts receivable from related companies	27,808	24,438
Inventories	306,901	361,954
Deposits paid to vendors	80,601	42,273
Prepaid expenses and other current assets	130,765	99,798
Total current assets	1,681,999	1,409,959
PROPERTY, PLANT AND EQUIPMENT, net	7,903,927	6,433,788
ADVANCES TO AND INVESTMENT IN AFFILIATES	1,590	86,167
GOODWILL	746,607	728,109
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	387,185	350,138
Total assets	$ 10,721,308	$ 9,008,161

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	September 30, 2008	December 31, 2007
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 549,813	$ 672,388
Accounts payable to related companies	37,535	48,483
Customer advances and deposits	139,656	75,831
Accrued and other current liabilities	246,630	220,847
Accrued capital expenditures	195,350	87,622
Interest payable	70,992	63,254
Current maturities of long-term debt	45,660	47,036
Total current liabilities	1,285,636	1,215,461
LONG-TERM DEBT, less current maturities	5,509,484	4,297,264
DEFERRED INCOME TAXES	101,700	102,762
OTHER LONG-TERM LIABILITIES	14,381	13,483
COMMITMENTS AND CONTINGENCIES (Note 12)		
	6,911,201	5,628,970
PARTNERS' CAPITAL:		
General Partner	159,044	160,193
Limited Partners:		
Common Unitholders (151,799,685 and 142,069,957 units authorized, issued and outstanding at September 30, 2008 and December 31, 2007, respectively)	3,641,184	3,192,092
Class E Unitholders (8,853,832 units authorized, issued and outstanding— held by subsidiary and reported as treasury units)	—	—
Accumulated other comprehensive income	9,879	26,906
Total partners' capital	3,810,107	3,379,191
Total liabilities and partners' capital	$ 10,721,308	$ 9,008,161

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)
(unaudited)

	Three Months Ended		Nine Months Ended	
	September 30, 2008	August 31, 2007	September 30, 2008	August 31, 2007
REVENUES:				
Natural gas operations	$ 1,938,586	$ 1,424,012	$ 6,322,070	$ 4,323,448
Retail propane	238,830	161,147	1,086,417	912,983
Other	28,799	41,167	90,575	167,161
Total revenues	2,206,215	1,626,326	7,499,062	5,403,592
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	1,435,308	1,089,968	4,965,145	3,323,717
Cost of products sold - retail propane	187,799	103,784	744,316	566,585
Cost of products sold - other	10,347	23,908	27,783	100,561
Operating expenses	197,493	144,507	573,606	427,219
Depreciation and amortization	70,508	52,591	191,757	145,353
Selling, general and administrative	44,252	39,428	136,632	118,347
Total costs and expenses	1,945,707	1,454,186	6,639,239	4,681,782
OPERATING INCOME	260,508	172,140	859,823	721,810
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(67,792)	(47,180)	(191,757)	(134,101)
Equity in earnings (losses) of affiliates	(654)	(51)	(749)	274
Gain (loss) on disposal of assets	2,520	(2,525)	1,584	(8,254)
Other, net	19,316	17,154	54,910	36,328
INCOME BEFORE INCOME TAXES AND MINORITY INTERESTS	213,898	139,538	723,811	616,057
Income tax expense (benefit)	(7,150)	3,202	8,754	10,062
INCOME BEFORE MINORITY INTERESTS	221,048	136,336	715,057	605,995
Minority interests	—	191	—	(888)
NET INCOME	221,048	136,527	715,057	605,107
GENERAL PARTNER’S INTEREST IN NET INCOME	80,252	62,046	233,599	182,575
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 140,796	$ 74,481	$ 481,458	$ 422,532
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.93	$ 0.54	$ 3.06	$ 2.79
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	149,839,499	136,980,931	145,160,079	136,978,832
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.93	$ 0.54	$ 3.05	$ 2.79
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	150,248,194	137,235,809	145,615,088	137,231,656

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)
(unaudited)

	Three Months Ended		Nine Months Ended	
	September 30, 2008	August 31, 2007	September 30, 2008	August 31, 2007
Net income	$ 221,048	$136,527	$ 715,057	$ 605,107
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(533)	(20,027)	(13,742)	(159,969)
Change in value of derivative instruments accounted for as cash flow hedges	6,969	47,686	(525)	122,514
Change in value of available-for-sale securities	(5,703)	(472)	(2,760)	499
	733	27,187	(17,027)	(36,956)
Comprehensive income	$ 221,781	$163,714	$ 698,030	$ 568,151

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, 2008
(Dollars in thousands)
(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2007	$ 160,193	$ 3,192,092	$ 26,906	$3,379,191
Distributions to partners	(242,735)	(420,425)	—	(663,160)
Net proceeds from issuance of Limited Partner Units	—	375,357	—	375,357
Capital contribution from General Partner	7,969	—	—	7,969
Tax effect of remedial income allocation from tax amortization of goodwill	—	(2,555)	—	(2,555)
Non-cash executive compensation	19	918	—	937
Non-cash unit-based compensation expense	—	14,338	—	14,338
Other comprehensive loss, net of tax	—	—	(17,027)	(17,027)
Net income	233,598	481,459	—	715,057
Balance, September 30, 2008	$ 159,044	$ 3,641,184	$ 9,879	$3,810,107

The accompanying notes are an integral part of this condensed consolidated financial statement.

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)
(unaudited)

	Nine Months Ended	
	September 30, 2008	August 31, 2007
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,022,585	$ 938,280
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(62,002)	(57,856)
Capital expenditures, net of contributions in aid of construction costs	(1,489,176)	(859,551)
(Advances to) repayments from affiliates, net	63,534	(41,041)
Proceeds from the sale of assets	20,232	15,616
Net cash used in investing activities	(1,467,412)	(942,832)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	4,744,414	3,166,657
Principal payments on debt	(3,526,971)	(2,629,111)
Net proceeds from issuance of Limited Partner Units	373,079	—
Distributions to partners	(663,160)	(496,774)
Capital contribution from General Partner	7,969	—
Debt issuance costs	(20,897)	(2,261)
Net cash provided by financing activities	914,434	38,511
INCREASE IN CASH AND CASH EQUIVALENTS	469,607	33,959
CASH AND CASH EQUIVALENTS, beginning of period	56,467	34,746
CASH AND CASH EQUIVALENTS, end of period	$ 526,074	$ 68,705

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, 2007, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners, L.P., and subsidiaries (collectively, "we" or the "Partnership") as of September 30, 2008 and for the three-month and nine-month periods ended September 30, 2008 and August 31, 2007, 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 of the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership's operations, maintenance activities and the impact of forward commodity prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the Partnership's consolidated financial position as of September 30, 2008, and its results of operations and cash flows for the three-month and nine-month periods ended September 30, 2008 and August 31, 2007. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto presented in the Partnership's Annual Report on Form 10-K for the fiscal year ended August 31, 2007, as filed with the SEC on October 30, 2007, and the Partnership's Report on Form 8-K as of December 31, 2007 and for the four-month transition period then ended, filed with the SEC on March 19, 2008.

In November 2007, we filed a Form 8-K indicating that our Limited Partnership Agreement had been amended to change our fiscal year end to the calendar year. Thus, our current fiscal year began on January 1, 2008. The Partnership completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the three-month and nine-month periods ended September 30, 2008 and the three-month and nine-month periods ended August 31, 2007 (the three and nine-month periods of the previous fiscal year most nearly comparable to the three and nine-month periods ended September 30, 2008).

We did not recast the financial data for the prior fiscal period because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Furthermore, we believe the information and data of the three and nine-month periods ended August 31, 2007 is comparable to what would have been reported for the three and nine-month periods ended September 30, 2007 if we had recast the prior period information. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the three and nine-month periods ended August 31, 2007 to the periods ended September 30, 2008 are substantially similar to what would have been reflected had we recast the information for the periods ended September 30, 2007.

Certain prior period amounts have been reclassified to conform to the fiscal 2008 presentation. These reclassifications had no impact on net income or total partners' capital for the periods presented.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through five subsidiary operating partnerships (collectively the "Operating Partnerships"), as follows:

- La Grange Acquisition, L.P., dba Energy Transfer Company ("ETC OLP"), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations;

- Energy Transfer Interstate Holdings, LLC ("ET Interstate"), the parent company of Transwestern Pipeline Company, LLC ("Transwestern") and ETC Midcontinent Express Pipeline, L.L.C. ("ETC MEP"), all of which are Delaware limited liability companies engaged in interstate transportation of natural gas;
- ETC Fayetteville Express Pipeline, L.L.C. ("ETC FEP"), a Delaware limited liability company engaged in interstate transportation of natural gas;
- Heritage Operating, L.P. ("HOLP"), a Delaware limited partnership primarily engaged in retail propane operations; and
- Titan Energy Partners, L.P. ("Titan"), a Delaware limited partnership engaged in retail propane operations.

The Partnership, the Operating Partnerships, and their subsidiaries are collectively referred to in this report as "we", "us", "ETP", "Energy Transfer" or the "Partnership."

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 natural gas liquids ("NGLs") in the states of Texas, Louisiana, New Mexico, Utah and Colorado.

Our interstate transportation operations principally consist of the natural gas transportation activities of the Transwestern Pipeline and also include the joint venture activities of ETC MEP and ETC FEP.

Our retail propane operations sell propane and propane-related products and services to residential, commercial, industrial and agricultural customers.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS:

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 transportation and storage segments 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 operating results estimated for the three and nine months ended September 30, 2008 and August 31, 2007 represent the actual results in all material respects.

Some of the other more 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, 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.

Significant Accounting Policies

Financial Assets and Liabilities at Fair Value

We adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*, ("SFAS 157") effective January 1, 2008. SFAS 157 provides a definition of fair value, establishes a fair value framework and hierarchy under GAAP and provides for expanded disclosures of fair value measurements. SFAS 157 does not require any new fair value measurements other than those established by other GAAP requirements. As noted below, under "New Accounting Standards", the effective date of SFAS 157 has been deferred with respect to certain non-financial assets and liabilities.

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. In accordance with SFAS 157, we determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “Level” as defined in SFAS 157. 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 Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. 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 our credit risk. Level 3 utilizes significant unobservable inputs. We currently do not have any fair value measurements within the scope of SFAS 157 that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations as defined by SFAS 157.

The following table summarizes the fair value of our financial assets and liabilities as of September 30, 2008 based on inputs used to derive their fair values in accordance with SFAS 157:

		Fair Value Measurements at Reporting Date Using	
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets			
Marketable Securities	$ 11,038	$ 11,038	$ —
Commodity Derivatives	53,981	50,830	3,151
Liabilities			
Commodity Derivatives	(23,856)	(4,751)	(19,105)
Interest Rate Derivatives	(945)	—	(945)
	$ 40,218	$ 57,117	$ (16,899)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated pipeline construction and production well tie-ins. Contributions in aid of construction costs (“CIAC”) are netted against our project costs as they are received, and the excess of any CIAC which exceeds our total projects costs is recognized as other income in the period in which it was realized. During the three and nine months ended September 30, 2008, $3.7 million and $46.3 million, respectively, of CIAC was received and netted against our project costs. During the three and nine months ended August 31, 2007, $1.8 million and $5.8 million, respectively, of CIAC was received and netted against our project costs. In March 2008, we received a reimbursement of $40.0 million related to an extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million which is recorded in other income on our condensed consolidated statement of operations for the nine months ended September 30, 2008. The total CIAC recorded to other income for the three-month periods ended September 30, 2008 and August 31, 2007 was $0.3 million and $0.2 million, respectively. For the nine months ended September 30, 2008 and August 31, 2007, the total CIAC recorded to other income was $8.2 million and $0.4 million, respectively.

New Accounting Standards

FASB Statement No. 141 (Revised 2007), *Business Combinations* (“SFAS 141R”). On December 4, 2007, the FASB issued SFAS 141R. SFAS 141R will significantly change the accounting for business combinations. Under SFAS 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. Statement 141R will change the accounting treatment for certain specific items, including:

- Acquisition costs will generally be expensed as incurred;

- Non-controlling interests (currently referred to as "minority interests") will be valued at fair value at the acquisition date;
- Acquired contingent liabilities will be recorded at fair value at the acquisition date and subsequently measured at either the higher of such amount or the amount determined under existing guidance for non-acquired contingencies;
- In-process research and development will be recorded at fair value as an indefinite-lived intangible asset at the acquisition date;
- Restructuring costs associated with a business combination will generally be expensed subsequent to the acquisition date; and
- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date generally will affect income tax expense.

SFAS 141R also includes a substantial number of new disclosure requirements. SFAS 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Earlier adoption is prohibited. Accordingly, we are required to record and disclose business combinations following existing GAAP until January 1, 2009.

EITF Issue No. 07-4, *Application of the Two Class Method Under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships ("MLP")* ("EITF 07-4"). The FASB ratified the final consensus on EITF 07-4 on March 26, 2008. The key elements of the final consensus relate to: (a) the scope of the issue; (b) when Incentive Distribution Rights ("IDRs") are considered participating securities under the two-class method for Earnings Per Share ("EPS"); (c) the calculation provisions; and (d) the transition and effective date. EITF 07-4 addresses how current period earnings of an MLP should be allocated to the general partner, limited partners, and, when applicable, the holder of IDRs when applying the two-class method under Statement 128. EITF 07-4 applies to MLPs that are required to make incentive distributions when certain thresholds have been met regardless of whether the IDR is a separate limited partner interest or embedded in the general partner interest. EITF 07-4 only addresses incentive distributions that are treated as equity distributions and does not address whether the incentive distributions are compensation or equity distributions. Specifically, if IDRs are separate from the general partner interest, then they are considered separate participating securities for purposes of applying the two-class method of determining EPS. Under this situation, the two-class method is used to determine EPS for the general partner interest, limited partner interest and the IDR holders' interest. EITF 07-4 provides that when earnings for the period exceed distributions, the excess undistributed earnings are to be allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership agreement related to the allocation of income. When distributions for the period exceed earnings, the income is first allocated equal to the actual distributions. The resulting deficit is allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership agreement related to the allocation of losses. EITF 07-4 is effective with the first fiscal year beginning after December 15, 2008, including interim periods within those fiscal years, and requires retrospective application of the guidance to all periods presented. Early application is prohibited. Accordingly, we are required to record and disclose EPS information following existing GAAP until January 1, 2009. While the actual impact of EITF 07-4 will depend on each specific period's earnings and distributions, the principles established in such EITF differ significantly from the present method used to compute earnings per unit when earnings exceed distributions. Depending on the actual earnings achieved, the impact of EITF 07-4 on the computation of our earnings per limited partner unit may be significant. Had we applied EITF 07-4 basic earnings per limited partner unit would have been $0.94 and $3.32 for the three and nine months ended September 30, 2008, respectively. Diluted earnings per limited partner unit would have been $0.94 and $3.31 for the three and nine months ended September 30, 2008, respectively.

FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1"). FSP EITF 03-6-1 was issued by the FASB on June 16, 2008. FSP EITF 03-6-1 clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We intend to adopt FSP EITF 03-6-1 effective January 1, 2009. Based on unvested unit awards currently outstanding, application of FSP EITF 03-6-1 would not have a material impact on our computation of earnings per unit.

FASB Staff Position ("FSP") SFAS 157-2, *Effective Date of FASB Statement No. 157 ("FSP 157-2")*. FSP 157-2 defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As allowed under FSP 157-2, we have not applied the provisions of SFAS 157 to our nonfinancial assets and liabilities measured at fair value, which include impaired nonfinancial assets and certain assets and liabilities acquired in business combinations. We are currently evaluating the impact of our adoption of FSP 157-2 effective January 1, 2009 on our consolidated financial statements. Although our adoption of FSP 157-2 on January 1, 2009, may require additional disclosure, we do not expect an impact to our financial condition or results of operations.

3. SIGNIFICANT ACQUISITIONS AND JOINT VENTURES:

Joint Ventures

Midcontinent Express Pipeline LLC

On December 13, 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. ("KMP") for a 50/50 joint development of Midcontinent Express Pipeline, an approximately 500-mile interstate natural gas pipeline that will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Transco's interstate natural gas pipeline in Butler, Alabama, which is currently pending necessary regulatory approvals. On February 14, 2007, Midcontinent Express Pipeline LLC ("MEP"), the entity formed to own and operate this pipeline, initiated public review of the project pursuant to the Federal Energy Regulatory Commission's ("FERC") National Environmental Policy Act ("NEPA") pre-filing review process. MEP filed its application with the FERC for a Certificate of Public Convenience and Necessity in October, 2007. In June 2008, the FERC issued an order approving this application. Mobilization for construction of this pipeline commenced in September 2008. The first phase of the pipeline is expected to be in service by the second quarter of 2009 and the second phase of the pipeline is expected to be in service by the third quarter of 2009. Total capital expenditures for the initial capacity of this project are estimated to be approximately $1.7 billion. In July 2008, MEP completed an open season with respect to a capacity expansion of MEP from the original planned capacity of 1.5 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to a planned interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional 300 MMcf/d of capacity was fully subscribed as a result of this open season. The planned expansion of capacity would be effectuated through the installation of additional compression on this segment of the pipeline and is expected to cost $0.2 billion. This expansion project is subject to MEP's filing of an application with, and approval from, the FERC.

ETP Enogex Partners LLC

In September 2008, we entered into an agreement with OGE Energy Corp. ("OGE") to form a joint venture entity to which OGE would contribute its Enogex midstream business and we would contribute our 100% equity interest in Transwestern Pipeline Company, our 50% equity interest in MEP and 100% of our interests in the Canyon Gathering System. The joint venture entity, ETP Enogex Partners LLC ("ETP Enogex Partners"), will be jointly owned and managed by us and OGE on a 50/50 basis. The parties are contractually obligated to take various actions to facilitate an initial public offering of ETP Enogex Partners as a master limited partnership following the closing of the transaction, including the creation of a master limited partnership structure pursuant to which we and OGE would each own 50% of the general partner entity that would be entitled to receive incentive distribution payments from ETP Enogex Partners.

The completion of the joint venture transaction is subject to obtaining specified financings on satisfactory terms, customary regulatory approvals and various third-party consents. In this regard, the agreement related to this transaction specifies that it is a condition to the obligations of each of us and OGE to consummate the joint venture transaction that ETP Enogex Partners obtain debt financings consisting of (i) the issuance by ETP Enogex Partners of a minimum of $700.0 million of senior notes having a 10-year maturity, (ii) the issuance by Transwestern Pipeline Company of $800.0 million of senior notes having a 10-year maturity and (iii) the arranging of a minimum of $700.0 million revolving credit facility for ETP Enogex Partners, in each case satisfying specified financing terms. If these financings are completed, ETP Enogex Partners would use the proceeds to repay Transwestern Pipeline Company's existing senior notes and its outstanding indebtedness to ETP, to repay Enogex's credit facility and its outstanding indebtedness to OGE, and to make a $266.0 million cash distribution to OGE. In such event, we would expect to receive approximately $600.0 million as repayment of the outstanding indebtedness owed to us by Transwestern Pipeline Company, which payment would significantly enhance our capital position.

Enogex operates a pipeline system engaged in natural gas gathering, compression, treating, dehydration, processing, transportation and storage. The Enogex system, located principally in Oklahoma, includes approximately 2,300 miles of natural gas transmission pipe and two storage facilities with total 2007 throughput of 1.52 Bcf/d, connecting to 11 different intrastate and interstate pipelines at 64 interconnection points. The storage fields have working gas capacity of 23 Bcf. Enogex has 175,000 horsepower of transmission compression. The Enogex gathering system has more than 5,534 miles of pipeline with connections to approximately 3,100 wells and 250 central receipt points, plus six active processing plants, with 723 MMcf/d of inlet capacity, and a 50% interest in an additional processing plant with 20 MMcf/d of inlet capacity. Enogex has 225,000 horsepower of owned gathering and processing compression.

Fayetteville Express Pipeline, LLC

In October, 2008, we entered into an agreement with KMP for a 50/50 joint development of Fayetteville Express Pipeline, an approximately 187-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 Quitman County, Mississippi. Fayetteville Express Pipeline, LLC ("FEP"), the entity formed to own and operate this pipeline, plans to initiate public review of the project pursuant to the FERC's NEPA pre-filing review process in November 2008. The pipeline will have an initial capacity of 2.0 Bcf/d. Pending necessary regulatory approvals, the approximately $1.3 billion pipeline project is expected to be in service by late 2010 or early 2011. FEP has secured binding 10-year commitments 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 Knight, Inc. Knight owns the general partner of KMP.

Canyon Acquisition

In October 2007, we acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the "Canyon acquisition") for $305.2 million in cash, subject to working capital adjustments as defined in the purchase and sale agreement. The Canyon Gathering System has over 400,000 dedicated acres under long-term contracts. The Canyon assets include a gathering system in the Piceance-Uinta Basin which consists of over 1,300 miles of 2-inch to 16-inch pipe with a projected capacity of over 300 MMcf/d, as well as six conditioning plants for NGL extraction and gas treatment with a processing capacity of 90 MMcf/d. Some of the largest U.S. producers are active in the area and are major customers of the system. The results of the Canyon Gathering System are included in our midstream segment since the acquisition date.

The Canyon acquisition was accounted for under the purchase method of accounting in accordance with FASB Statement No. 141, *Business Combinations*, ("SFAS 141"). The purchase price was initially allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. We completed the purchase price allocation during the third quarter of 2008. The adjustments to the purchase price allocation were not material. The final allocations of the purchase price are noted below:

Accounts receivable	$ 3,613
Inventory	183
Prepaid and other current assets	1,606
Property, plant, and equipment	284,910
Contract rights and customer lists (6 to 15 year life)	6,351
Goodwill	11,359
Total assets acquired	308,022
Accounts payable	(1,840)
Customer advances and deposits	(1,030)
Total liabilities assumed	(2,870)
Net assets acquired	$305,152

The Canyon acquisition was not material for pro forma disclosure purposes.

Other

In March 2008 we made a purchase price adjustment for a contingent payment associated with a natural gas gathering system in north Texas purchased in September 2006. The purchase and sale agreement had a contingent payment not to exceed $25.0 million which was to be determined eighteen months after the closing date. The contingent payment of $8.7 million was recorded as an adjustment to goodwill in the midstream segment.

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

At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation ("FDIC") insurance limit.

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

	Nine Months Ended	
	September 30, 2008	August 31, 2007
Net income	$ 715,057	$605,107
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	191,757	145,353
Amortization in interest expense	4,240	3,222
Provision for loss on accounts receivable	4,734	3,839
Non-cash executive compensation	937	—
Non-cash unit-based compensation expense	14,338	7,307
Deferred income taxes	(3,781)	(4,148)
(Gain) loss on disposal of assets	(1,584)	8,254
Distributions in excess of equity in earnings (losses) of affiliates, net	4,723	(274)
Minority interests and other	—	237
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	214,348	(21,283)
Accounts receivable from related companies	(3,063)	(5,662)
Inventories	58,412	308,638
Deposits paid to vendors	(38,328)	33,737
Prepaid expenses and other	(36,188)	10,890
Intangibles and other long-term assets	(16,074)	(3,263)
Regulatory assets	(15,587)	663
Accounts payable	(149,801)	(77,660)
Accounts payable to related companies	(10,970)	17,472
Customer advances and deposits	63,795	(20,870)
Accrued and other current liabilities	17,891	(18,484)
Other long-term liabilities	1,295	(1,253)
Price risk management liabilities, net	6,434	(53,542)
Net cash provided by operating activities	$ 1,022,585	$938,280

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Nine Months Ended September 30, 2008	Nine Months Ended August 31, 2007
NON-CASH INVESTING ACTIVITIES:		
Transfer of investment in affiliate in purchase of Transwestern	$ —	$956,348
Investment in Calpine Corporation received in exchange for accounts receivable	$ 10,826	$ —
NON-CASH FINANCING ACTIVITIES:		
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 4,686	$533,625
Issuance of Common Units in connection with certain acquisitions	$ 2,278	$ —
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for interest, net of $24,331 and $18,713 capitalized for the nine months ended September 30, 2008 and August 31, 2007, respectively	$ 203,578	$162,298
Cash paid for income taxes	$ 10,340	$ 5,546

5. ACCOUNTS RECEIVABLE:

Accounts receivable consisted of the following:

	September 30, 2008	December 31, 2007
Midstream and intrastate transportation and storage	$ 460,831	$ 612,533
Interstate transportation	24,289	31,676
Propane	120,015	183,516
Less - allowance for doubtful accounts	(6,323)	(5,698)
Total, net	$ 598,812	$ 822,027

We exchanged a portion of our outstanding accounts receivable from Calpine Energy Services, L.P. for Calpine Corporation (“Calpine”) common stock during the first quarter of 2008 pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock is included as marketable securities which are classified as available-for-sale securities and reflected as a current asset on the condensed consolidated balance sheet as of September 30, 2008 at a fair value of $8.6 million.

Table of Contents

6. INVENTORIES:

Inventories consisted of the following:

	September 30, 2008	December 31, 2007
Natural gas and NGLs, excluding propane	$ 189,125	$ 268,148
Propane	95,952	74,309
Appliances, parts and fittings and other	21,824	19,497
Total inventories	$ 306,901	$ 361,954

7. GOODWILL, INTANGIBLES AND OTHER LONG-TERM ASSETS:

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

	September 30, 2008		December 31, 2007	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (5 to 15 years)	$ 39,875	$ (23,144)	$ 34,855	$ (19,438)
Customer lists (3 to 15 years)	143,431	(36,440)	139,097	(26,821)
Contract rights (6 to 15 years)	23,015	(3,270)	23,015	(1,849)
Other (10 years)	2,677	(2,049)	2,677	(1,463)
Total amortizable intangible assets	208,998	(64,903)	199,644	(49,571)
Non-amortizable assets - Trademarks	72,148	—	70,339	—
Total intangible assets	281,146	(64,903)	269,983	(49,571)
Other long-term assets:				
Financing costs (3 to 15 years)	55,165	(15,020)	42,432	(10,578)
Regulatory assets	91,292	(5,081)	73,687	(2,623)
Other	44,586	—	26,808	—
Total intangibles and other long-term assets	$ 472,189	$ (85,004)	$ 412,910	$ (62,772)

Aggregate amortization expense of intangible and other long-term assets was as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2008	August 31, 2007	September 30, 2008	August 31, 2007
Reported in depreciation and amortization	$ 4,391	$ 4,200	$ 13,011	$ 12,589
Reported in interest expense	$ 1,590	$ 1,264	$ 4,442	$ 3,757

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

Years Ending December 31:	
2008 (remainder)	$ 6,643
2009	25,611
2010	23,692
2011	22,254
2012	20,216

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 December 31 for our interstate segment and as of August 31 for all others. No impairment was required for the three and nine-month periods ended September 30, 2008 or August 31, 2007.

8. INCOME TAXES:

The components of our federal and state income tax provision are summarized as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2008	August 31, 2007	September 30, 2008	August 31, 2007
Current provision (benefit):				
Federal	$ (7,826)	$ 917	$ (1,192)	$ 4,745
State	5,072	3,515	13,856	9,463
Total	(2,754)	4,432	12,664	14,208
Deferred provision (benefit):				
Federal	(4,915)	(2,026)	(4,091)	(4,667)
State	519	796	181	521
Total	(4,396)	(1,230)	(3,910)	(4,146)
Total tax provision	$ (7,150)	$ 3,202	$ 8,754	$ 10,062
Effective tax rate	(3.34)%	2.29%	1.21%	1.63%

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.

9. INCOME PER LIMITED PARTNER UNIT:

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

	Three Months Ended		Nine Months Ended	
	September 30, 2008	August 31, 2007	September 30, 2008	August 31, 2007
Net income	$ 221,048	$ 136,527	$ 715,057	$ 605,107
Adjustments:				
General Partner's equity ownership	(4,421)	(2,731)	(14,301)	(12,102)
General Partner's incentive distributions	(75,831)	(59,315)	(219,298)	(170,473)
Limited Partners' interest in net income	140,796	74,481	481,458	422,532
Additional earnings allocation to General Partner	(861)	—	(37,456)	(40,054)
Net income available to limited partners	$ 139,935	$ 74,481	$ 444,002	$ 382,478
Weighted average limited partner units – basic	149,839,499	136,980,931	145,160,079	136,978,832
Basic net income per limited partner unit	$ 0.93	$ 0.54	$ 3.06	$ 2.79
Weighted average limited partner units	149,839,499	136,980,931	145,160,079	136,978,832
Dilutive effect of Unit Grants	408,695	254,878	455,009	252,824
Weighted average limited partner units, assuming dilutive effect of Unit Grants	150,248,194	137,235,809	145,615,088	137,231,656
Diluted net income per limited partner unit	$ 0.93	$ 0.54	$ 3.05	$ 2.79

Table of Contents

10. DEBT OBLIGATIONS:

Our debt obligations consisted of the following:

	September 30, 2008	December 31, 2007	Payment Terms
ETP Senior Notes:			
6.0% Senior Notes, net of discount of $607	$ 349,393	$ —	One payment of $350,000 due July 13, 2013. Interest is paid semi-annually.
6.7% Senior Notes, net of discount of $1,703	598,297	—	One payment of $600,000 due July 2, 2018. Interest is paid semi-annually.
7.5% Senior Notes, net of discount of $5,717	544,283	—	One payment of $550,000 due July 1, 2038. Interest is paid semi-annually.
6.125% Senior Notes, net of discount of $302 and $322, respectively	399,698	399,678	One payment of $400,000 due February 15, 2017. Interest is paid semi-annually.
6.625% Senior Notes, net of discount of $2,211 and $2,231, respectively	397,789	397,769	One payment of $400,000 due October 15, 2036. Interest is paid semi-annually.
5.95% Senior Notes, net of discount of $1,582 and $1,733, respectively	748,418	748,267	One payment of $750,000 due February 1, 2015. Interest is paid semi-annually.
5.65% Senior Notes, net of discount of $246 and $288, respectively	399,754	399,712	One payment of $400,000 due August 1, 2012. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Notes, including premium of $3,644 and $4,077, respectively	91,644	92,077	One payment of $88,000 due November 17, 2014. Interest is paid semi-annually.
5.54% Senior Notes, net of discount of $4,462 and $4,855, respectively	120,538	120,145	One payment of $125,000 due November 17, 2016. Interest is paid semi-annually.
5.64% Senior Notes	82,000	82,000	One payment due May 24, 2017. Interest is paid semi-annually.
5.89% Senior Notes	150,000	150,000	One payment due May 24, 2022. Interest is paid semi-annually.
6.16% Senior Notes	75,000	75,000	One payment due May 24, 2037. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
8.55% Senior Secured Notes	36,000	48,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
Medium Term Note Program: 7.17% Series A Senior Secured Notes	4,800	4,800	Annual payments of $2,400 due each November 19 through 2009. Interest is paid semi-annually.
7.26% Series B Senior Secured Notes	10,000	10,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
Senior Secured Promissory Notes: 8.55% Series B Senior Secured Notes	9,143	13,714	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	11,500	15,500	Annual payments of $4,000 due August 15, 2008, and $5,750 due each August 15, 2009 and 2010. Interest is paid quarterly.

8.67% Series D Senior Secured Notes	45,550	58,000	Annual payments of $12,450 due August 15, 2008 and 2009, $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	7,000	7,000	Annual payments of $1,000 due each August 15, 2009 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.21% Series G Senior Secured Notes	—	3,800	Paid and retired in May 2008.
7.89% Series H Senior Secured Notes	5,818	6,545	Annual payments of $727 due each May 15 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment of $16,000 due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility (including Swingline loan option)	1,387,785	1,626,948	Available through June 2012. See terms below under "ETP Credit Facility".
HOLP Fourth Amended and Restated Senior Revolving Credit Facility	10,000	15,000	Available through June 30, 2011. See terms below under "HOLP Credit Facility".
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 7.775% and 5.51 % for September 30, 2008 and December 31, 2007, respectively	11,863	11,171	Due in installments through 2014.
Other	2,871	3,174	Due in installments through 2024.
	5,555,144	4,344,300	
Current maturities	(45,660)	(47,036)	
	$5,509,484	$4,297,264	

Future maturities of long-term debt for each of the next five years and thereafter are as follows:

2008 (remainder)	$ 5,380
2009	55,459
2010	40,656
2011	34,336
2012	1,810,555
Thereafter	3,608,758
	$5,555,144

ETP 2008 Senior Notes

In March 2008, we issued a total of $1.5 billion aggregate principal amount of Senior Notes comprised of $350.0 million of 6.00% Senior Notes due 2013, $600.0 million of 6.70% Senior Notes due 2018, and $550.0 million of 7.50% Senior Notes due 2038 (collectively, the "ETP 2008 Senior Notes"). The Partnership may redeem some or all of the ETP 2008 Senior Notes at any time, or from time to time, pursuant to the terms of the indenture. We used the proceeds of approximately $1.48 billion (net of bond discounts of $8.2 million and other offering costs of $10.8 million) from the issuance of the ETP 2008 Senior Notes to repay other indebtedness.

The ETP 2008 Senior Notes were issued under an indenture containing covenants, which, among other things, restrict our ability to, subject to certain exceptions, incur debt secured by liens, engage in sale and leaseback transactions or merge or consolidate with another entity or sell substantially all of our assets. The ETP 2008 Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP 2008 Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP 2008 Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

ETP Credit Facility

We have a $2.0 billion revolving credit facility (the "ETP Credit Facility") 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) which 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 a rate based on either a Eurodollar rate or a prime rate.

As of September 30, 2008, there was a balance of $1.39 billion outstanding under the ETP Credit Facility. The weighted average interest rate on the total amount outstanding at September 30, 2008, was 3.36%. The total amount available under the ETP Credit Facility, as of September 30, 2008, which is reduced by outstanding letters of credit, was approximately $588.0 million. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our other current and future unsecured debt.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") is 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. As of September 30, 2008, there was $10.0 million outstanding on the revolving credit loans. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Credit Facility. There were outstanding letters of credit of $1.0 million at September 30, 2008. The sum of the loans made under the HOLP Credit Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Credit Facility. The amount available at September 30, 2008 was $64.0 million.

11. PARTNERS' CAPITAL AND UNIT-BASED COMPENSATION PLANS:

Common Units Issued

The change in Common Units during the nine-month period ended September 30, 2008 is as follows:

	Number of Units
Balance, beginning of period	142,069,957
Common Units issued in connection with a public offering	9,662,500
Common Units issued in connection with certain acquisitions	53,893
Common Units issued under the 2004 Unit Plan	13,335
Balance, end of period	151,799,685

On January 8, 2008, we issued 750,000 Common Units at $48.81 per Common Unit to the underwriters pursuant to the exercise of a 30-day option to purchase Common Units to cover Over-Allotments in connection with a public offering of 5,000,000 ETP Common Units, representing limited partner interests, in December 2007. The proceeds of $35.0 million, net of offering costs, were used to repay borrowings from the ETP Credit Facility.

On July 21, 2008, we issued 7,750,000 Common Units representing limited partner interests at $39.45 per Common Unit in connection with a public offering. We also granted the underwriters a 30-day option to purchase up to an aggregate of 1,162,500 additional Common Units ("Over-Allotment"), which was immediately exercised with the equity issuance. Net proceeds of approximately $338.0 million from the offering and Over-Allotment were used to repay a portion of the amount outstanding under the ETP Credit Facility. We received a $7.2 million capital contribution from our general partner to maintain its 2% general partner's interest in September of 2008.

Quarterly Distributions of Available Cash

On February 14, 2008, we paid a one-time distribution related to the four-month transition period ended December 31, 2007 of $1.125 per Common Unit ($3.375 per Limited Partner Unit annualized) to Unitholders of record as of the close of business on February 1, 2008 (an increase of $0.075 per unit on an annualized basis). Our General Partner's Incentive Distribution Rights entitle it to receive incentive distributions to the extent that quarterly distributions to our Unitholders exceed $0.275 per unit (which amount represents $1.10 per unit on an annualized basis).

On February 18, 2008, we paid a one-time distribution related to the four-month transition period ended December 31, 2007 of $90.9 million in the aggregate for ETP GP's 2% general partner interest in the Partnership and its Incentive Distribution Rights.

On May 15, 2008, we paid a per unit cash distribution for the three months ended March 31, 2008 of $0.86875 ($3.475 per Limited Partner Unit annualized) to Unitholders of record as of the close of business on May 5, 2008 (a $0.10 increase from the previous distribution per Limited Partner Unit). We paid $71.8 million in the aggregate for ETP GP's 2% general partner interest in the Partnership and its Incentive Distribution Rights for the three months ended March 31, 2008.

On August 14, 2008, we paid a per unit cash distribution of $0.89375 ($3.575 per Limited Partner Unit annualized) for the three months ended June 30, 2008, to Unitholders of record as of the close of business on August 7, 2008 (a $0.10 increase per Limited Partner Unit on an annualized basis from the previous distribution). We paid $80.1 million in the aggregate for ETP GP's 2% general partner interest in the Partnership and its Incentive Distribution Rights for the three months ended June 30, 2008.

On October 31, 2008, we declared a per unit cash distribution of $0.89375 ($3.575 per Limited Partner Unit annualized) for the three months ended September 30, 2008, which will be paid on November 14, 2008 to Unitholders of record as of the close of business on November 10, 2008.

Total distributions declared (all from Available Cash from Operating Surplus) related to the nine months ended September 30, 2008 were as follows:

Limited Partners -	
Common Units	$395,622
Class E Units	9,363
General Partner -	
2% Ownership	12,740
Incentive Distribution Rights	219,298
	$637,023

Unit-Based Compensation Plans

We recognized non-cash unit-based compensation expense of $2.3 million for the three months ended September 30, 2008. The non-cash unit-based compensation expense for the three months ended August 31, 2007 was not significant. For the nine months ended September 30, 2008 and August 31, 2007 we recognized non-cash unit-based compensation expense of $14.3 million and $7.3 million, respectively, as discussed below. For purposes of recognizing non-cash compensation expense, we calculate the grant date fair value assuming a risk-free interest rate based on the current treasury rate and expected distributions based on the most recently declared distribution as of the grant date.

2004 Unit Plan

Our Amended and Restated 2004 Unit Award Plan (the "2004 Unit Plan") provides for awards of ETP Common Units and other rights to our employees, officers and directors. As of September 30, 2008, 581,125 ETP Common Units were available for future grants under the 2004 Unit Plan.

Employee Grants

Prior to December 2007, substantially all of the awards granted to employees under the 2004 Unit Plan required the achievement of performance objectives in order for the awards to become vested. The expected life of each unit award subject to the achievement of performance objectives is assumed to be the minimum vesting period under the performance objectives of such unit award. Generally, each award was structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three year period. The performance criteria was generally based upon the total return (unit price appreciation plus cash distributions) to our Unitholders as compared to a group of publicly traded partnership peer companies. Non-cash compensation expense is recorded based upon the total awards granted over the required service period that are expected to vest based on the estimated level of achievement of performance objectives. As circumstances change, cumulative adjustments of previously-recognized compensation expense are recorded.

Since December 2007, we have also granted unit awards to employees that vest 20% per year over a five year period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives.

The following table shows the activity of the employee grants during the nine months ended September 30, 2008:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2007	1,039,529	$ 42.27
Awards granted	47,000	39.92
Awards vested	(61,336)	44.07
Awards forfeited	(198,844)	40.47
Unvested awards as of September 30, 2008	826,349	$ 42.43

The total expected non-cash compensation expense to be recognized related to the unvested employee awards as of September 30, 2008 was:

Years Ending December 31:	
2008 (remainder)	$3,757
2009	7,291
2010	3,620
2011	1,979
2012	831

Director Grants

The following table shows the activity of the Director Grant Awards during the nine months ended September 30, 2008:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2007	6,928	$ 40.47
Awards granted	4,470	38.45
Awards vested	(2,752)	42.32
Unvested awards as of September 30, 2008	8,646	$ 38.83

The total expected non-cash compensation expense to be recognized related to the unvested Director Awards as of September 30, 2008 was:

Years Ending December 31:	
2008 (remainder)	$ 38
2009	122
2010	44
2011	10

Related Party Awards

During 2007, a partnership (McReynolds Equity Partners, L.P.), the general partner of which is owned and controlled by the President of our General Partner, awarded to certain new officers of ETP certain rights related to units of Energy Transfer Equity, L.P. ("ETE") previously issued by ETE to such officer. These rights include the economic benefits of ownership of these units based on a five year vesting schedule whereby the officer will vest in the units at a rate of 20% per year. None of the costs related to such awards are paid by ETP or ETE. Based on GAAP covering related party transactions and unit-based compensation arrangements, we are recognizing non-cash compensation expense over the vesting period based on the grant date fair value of the ETE units awarded the ETP employees assuming no forfeitures. In December 2007, rights related to 55,000 of the ETE units vested, rights related to 60,000 ETE units vested in March 2008, and rights related to 20,000 ETE units vested in June, 2008. In June 2008, rights related to 240,000 ETE units were forfeited due to the resignation of an officer of ETP.

On July 22, 2008, rights related to 240,000 ETE units were awarded to ETP's current chief financial officer. This award has similar terms to those discussed above, including vesting over five years at 20% per year. None of the costs related to this award will be paid by ETP or ETE.

As of September 30, 2008, rights related to 540,000 unvested ETE units remained outstanding. For the three months ended September 30, 2008 and August 31, 2007, we recognized non-cash compensation expense of $1.4 million and $2.6 million, respectively, related to these awards. For the nine-month periods ended September 30, 2008 and August 31, 2007, we recognized non-cash compensation expense, net of forfeitures, of $1.7 million and $5.2 million, respectively, as a result of these awards. As these units were outstanding prior to these awards, these awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE. As of September 30, 2008, we expect to recognize non-cash compensation expense as follows in future periods related to these awards:

Years Ending December 31:	
2008 (remainder)	$1,645
2009	4,872
2010	2,819
2011	1,526
2012	563
2013	161

Accumulated Other Comprehensive Income

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

	September 30, 2008	December 31, 2007
Net gain on commodity related hedges	$ 11,951	$ 25,497
Net gain on interest rate hedges	233	926
Unrealized gains (losses) on available-for-sale securities	(2,305)	483
Total AOCI, net of tax	$ 9,879	$ 26,906

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

Regulatory Matters

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 ("Stipulation and Agreement") that resolved the primary components of the rate case. Transwestern's tariff rates and fuel charges are now final for the period of the settlement. Transwestern is not required to file a new rate case until October 1, 2011.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern's existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern's existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity ("Order"). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. On December 17, 2007, two parties filed requests for rehearing of the Order and on December 20, 2007, one party filed a motion to stay the Order. On February 21, 2008, the FERC reaffirmed its decision in the Order; thus, Transwestern notified customers of the commencement of construction in January 2008. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area is expected to be in service during the fourth quarter of 2008.

As discussed in Note 3, certain regulatory approvals are still pending with respect to the expansion and interim service of MEP.

Guarantees

On February 29, 2008, MEP entered into a credit agreement that provides for a $1.4 billion senior revolving credit facility (the "MEP Facility"). We have guaranteed 50% of the obligations of MEP under the MEP Facility, with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage 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 also has a swingline loan option with a maximum borrowing of $25.0 million at a prime rate. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit available under the MEP Facility. The indebtedness under the MEP Facility is prepayable at any time at the option of MEP without penalty. 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. The MEP Facility is syndicated among multiple financial institutions; the Royal Bank of Scotland PLC is the administrative agent. Among the lending banks that make up the syndicate of financial institutions for the MEP Facility, affiliates of Lehman Brothers provide less than 10% of the $1.4 billion available. MEP expects the MEP Facility to be reduced by the amount of the Lehman Brothers affiliates' commitment. However, the MEP Facility is not defaulted, and the commitments of the other lending banks remain unchanged.

In March 2008, MEP reimbursed ETP a net $63.5 million from the MEP Facility for previous advances ETP made to MEP. As of September 30, 2008, MEP had $525.0 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. The weighted average interest rate on the total amount outstanding as of September 30, 2008 was 3.55%. The total amount available under the MEP Facility was $841.7 million as of September 30, 2008.

Prior to September 30, 2008, MEP also had a $197.0 million reimbursement agreement under which MEP could issue letters of credit. This reimbursement agreement expired on September 30, 2008 and there are no longer any letters of credit outstanding.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and 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 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 2020. Rental expense under these operating leases totaled approximately $6.3 million and $11.7 million for the three-month periods ended September 30, 2008 and August 31, 2007, respectively, and has been included in operating expenses in the accompanying condensed consolidated statements of operations. For the nine-month periods ended September 30, 2008 and August 31, 2007, rental expense totaled approximately $21.7 million and $27.0 million, respectively, for operating leases.

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 coverages 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/CFTC 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 has 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 has 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 Natural Gas Act (“NGA”). We allegedly 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. Additionally, the FERC has alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. Our Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (“NGPA”) Section 311 authority and is subject to the FERC-approved rates, terms and conditions of service. The allegations related to the Oasis pipeline include claims that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at market-based prices, which activity is expected to account for approximately 1.0% of our operating income for our 2008 calendar year. If the FERC is successful in revoking our blanket marketing authority, our sales of natural gas at market-based prices would be limited to sales to retail customers (such as utilities and other end users) and sales from our own production, if any, and any other sales of natural gas by us would be required to be made at contract prices that would be subject to individual FERC approval.

In its Order and Notice, the FERC is seeking $70.1 million in disgorgement of profits, plus interest, and $97.5 million in civil penalties relating to these matters. The FERC has taken the position that, once it receives our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. On August 27, 2007, ETP filed a request for rehearing of the Order and Notice. On December 20, 2007, the FERC issued an order denying rehearing and directed FERC Staff to file a brief recommending disposition of issues by order or by evidentiary hearing. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC's claims and requested a dismissal of the FERC proceeding. On February 14, 2008, the Enforcement Staff of the FERC filed a brief recommending that the FERC refer various matters relating to its market manipulation allegations for an evidentiary hearing before a FERC administrative law judge. The Enforcement Staff also recommended that FERC issue an order assessing the $15.5 million portion of the above-referenced penalty against ETP with respect to the allegations related to ETP's Oasis Pipeline and that the Oasis-related penalty assessment, if not paid, then be referred by the FERC to a federal district court for *de novo* review. The Enforcement Staff also recommended that the FERC impose certain changes in Oasis' business operations and refunds to certain Oasis customers as previously proposed in the Order and Notice. Finally, the Enforcement Staff 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 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. If the FERC pursues the claims related to this additional month, the total amount of civil penalties and disgorgement of profits sought by the FERC would be approximately $200.0 million. On March 31, 2008, we responded to the Enforcement Staff's brief. On April 25, 2008, the Enforcement Staff filed an answer to our March 31, 2008 pleading. On May 15, 2008, the FERC ordered hearings to be conducted by FERC administrative law judges with respect to the FERC's Oasis claims and market manipulation claims. The hearing related to the Oasis claims is scheduled to commence in December 2008 with the administrative law judge's initial decision due by May 11, 2009 and the hearing related to the market manipulation claims is scheduled to commence in April 2009 with the administrative law judge's initial decision due by October 26, 2009. The FERC denied our request for dismissal of the proceeding and has ordered that, following the completion of the hearings, the administrative law judges make recommendations with respect to whether we engaged in market manipulation in violation of the NGA and FERC regulations and whether Oasis violated the NGPA and FERC regulations. The FERC reserved for itself the issues of possible civil penalties, revocation of our blanket market certificate, method by which we and Oasis would disgorge any unjust profits and whether any conditions should be placed on Oasis's Section 311 authorization. Following the issuance of each of the administrative law judge's initial decision, the FERC would then issue an order with respect to each of these matters. On May 23, 2008, we requested rehearing and stay of the FERC's May 15, 2008 order establishing hearing, and we renewed those requests on June 26, 2008. On August 7, 2008, FERC denied rehearing of its May 15, 2008 order. On August 8, 2008, we filed a petition with the U.S. Court of Appeals for the Fifth Circuit to review and set aside FERC's May 15 and August 7, 2008 orders on the grounds that we are entitled to adjudicate FERC's claims in federal district court pursuant to the NGA and the NGPA.

It is our position that our trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC holds substantial enforcement authority. At this time, we are unable to predict the final outcome of these matters.

On July 26, 2007, the United States Commodity Futures Trading Commission (the "CFTC") filed suit in United States District Court for the Northern District of Texas alleging that we violated provisions of the Commodity Exchange Act (the "CEA") by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, ETP entered into a consent order with the CFTC (the "Consent Order"). Pursuant to the Consent Order, ETP agreed to pay the CFTC $10.0 million and the CFTC agreed to release ETP and its affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that ETP is permanently enjoined from attempting to manipulate the price of any commodity in interstate commerce in violation of the CEA. By consenting to the entry of the Consent Order, ETP neither admitted nor denied the allegations made by the CFTC in this proceeding. The settlement reduced our existing accrual and was paid from cash flow from operations in March 2008.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE for damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETE for claims related to the FERC claims. These suits contain 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, and seek unspecified direct, indirect, consequential and exemplary damages. We are seeking to compel arbitration in several of these suits on the grounds that the claims are subject to arbitration agreements, and one suit is pending before the Texas Supreme Court on issues of arbitrability. One of the suits against us and ETE contains an additional allegation that the defendants transported gas in a manner that favored their affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producers/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We have filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable. The claimants have agreed to a stay of the arbitration pending resolution of cross-motions for summary judgment in the state court proceeding, which were heard by the court on August 29, 2008.

A consolidated class action complaint has been filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the New York Mercantile Exchange, or NYMEX, in violation of the CEA. It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions and intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action, and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008 we filed a motion to dismiss the second consolidated complaint. On June 19, 2008 the plaintiffs filed a response opposing our motion to dismiss. We filed a reply in support of our motion on July 9, 2008.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit from our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On July 2, 2008 the plaintiffs filed a response opposing our motion to dismiss. We filed a reply in support of our motion on August 18, 2008.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such expenses are incurred. In addition, our existing accruals for litigation and contingencies include an accrual related to these matters. At this time, we are unable to predict the outcome of these matters; however, it is possible that the amount we become obliged to pay as a result of the final resolution of these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of our accrual related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our existing accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available for distributions either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

In re Natural Gas Royalties Qui Tam Litigation. MDL Docket No. 1293 (D. WY), Jack Grynberg, an individual, has filed actions against a number of companies, including Transwestern, now transferred to the U.S. District Court for the District of Wyoming, for damages for mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against Transwestern. Transwestern believes that its measurement practices conformed to the terms of its FERC Gas Tariff, which were filed with and approved by the FERC. As a result, Transwestern believes that is has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Transwestern complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal which may be taken from the dismissal of the Grynberg case. A hearing was held on April 24, 2007 regarding Transwestern's Supplemental Brief for Attorneys' fees which was filed on January 8, 2007 and the issues are submitted and are awaiting a decision. Grynberg moved to have the cases he appealed remanded to the district court for consideration in light of a recently-issued Supreme Court case. The defendants/appellees opposed the motion. The Tenth Circuit motions panel referred the remand motion to the merits panel to be carried with the appeals. Grynberg's opening brief was filed on or about July 31, 2007. Appellee's opposition brief was filed on or about November 21, 2007. Appellee Transwestern filed its separate response brief on January 11, 2008 and Grynberg's reply brief was filed in June 2008 and the hearing on all briefs was held in September 2008, with a ruling expected in the near future. Transwestern does not believe the outcome of this case will have a material adverse effect on its financial position, results of operations or cash flows.

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 engaged in ongoing 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". Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have 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 $1.0 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. AEP filed a notice of motion for reconsideration questioning the court's damages calculation. AEP will determine whether it will appeal the court decision once a final judgment is entered. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP does not expect that it will be liable for any portion of this court award.

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 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.

As of September 30, 2008 and December 31, 2007, an accrual of $20.9 million and $30.5 million, respectively, was recorded as accrued and other current liabilities and other non-current liabilities on our condensed consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters.

Environmental

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and 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 and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. 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 health, and the handling, storage, use, and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include historical remediation obligations at several compressor sites on the Transwestern system for presence of polychlorinated biphenyls (“PCBs”) which are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $9.2 million. Transwestern received FERC approval for rate recovery of the portion of soil and groundwater remediation not related to PCBs effective April 1, 2007.

Environmental regulations were recently modified for United States Environmental Protection Agency’s Spill Prevention, Control and Countermeasures (“SPCC”) 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.

In July 2001, HOLP acquired a company that had previously received a request for information from the U.S. Environmental Protection Agency (the “EPA”) regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called “Superfund”). We have not received any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. Based upon information currently available to us, it is believed that HOLP’s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

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 amount has been recorded in our September 30, 2008 or our December 31, 2007 condensed 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.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of September 30, 2008 and December 31, 2007, an accrual on an undiscounted basis of $13.3 million and $15.7 million was recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL acquisition, the Transwestern acquisition, and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

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

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 regulations 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." Through September 30, 2008, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2009. Through September 30, 2008, a total of $6.8 million of capital costs and $12.4 million of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. Through September 30, 2008, a total of $5.5 million of capital costs and $0.3 million of operating and maintenance costs have been incurred for pipeline integrity costs for Transwestern. 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.

13. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. The payments on margin deposits occur 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. We had net deposits with derivative counterparties of $80.6 million and $42.2 million as of September 30, 2008 and December 31, 2007, respectively, reflected as deposits paid to vendors on our condensed consolidated balance sheets.

Non-trading Activities

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the condensed consolidated statements of operations. We reclassified into earnings gains of $0.5 million and $19.6 million for the three months ended September 30, 2008 and August 31, 2007, respectively, and gains of $13.3 million and $159.4 million for the nine months ended September 30, 2008 and August 31, 2007, respectively, related to commodity financial instruments that were previously reported in AOCI.

We expect gains of $11.9 million related to commodity derivatives to be reclassified into earnings over the next twelve months related to income currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Table of Contents

Trading Activities

Due to a high level of market volatility as well as other business considerations, as of July 2008 we determined that we will no longer engage in the trading of financial derivative instruments that are not offset by physical positions. As a result, we will no longer have any material exposure to market risk from such derivative positions. The derivative contracts that were previously entered into for trading purposes are recognized in the condensed consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in midstream and intrastate transportation and storage revenue in the condensed consolidated statements of operations on a net basis. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.2 million for the nine months ended September 30, 2008, net gains of approximately $2.2 million for the fiscal year ended August 31, 2007 and net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007.

The following table details the outstanding commodity-related derivatives and their fair values:

September 30, 2008

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	44,577,500	2008-2011	$ (4,670)
Swing Swaps IFERC	Gas	(15,631,000)	2008-2009	4,035
Fixed Swaps/Futures	Gas	(14,722,500)	2008-2010	34,381
Forward Physical Contracts	Gas	122,000	2008	16
Options	Gas	(122,000)	2008	(16)
Forwards/Swaps - in Gallons	Propane	55,440,000	2008-2009	(15,075)
				18,671
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	—	2008-2009	(1,819)
				16,852
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(5,910,000)	2008-2009	8
Fixed Swaps/Futures	Gas	(5,910,000)	2008-2009	13,265
				13,273
				$ 30,125

December 31, 2007

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	2,732,500	2008-2009	$ (2,767)
Swing Swaps IFERC	Gas	(4,640,000)	2008	(1,515)
Fixed Swaps/Futures	Gas	(26,987,500)	2008-2009	14,230
Forward Physical Contracts	Gas	(17,847,140)	2008	(1,063)
Options	Gas	(670,000)	2008	(161)
Forward/Swaps - in Gallons	Propane	9,282,000	2008	3,319
				12,043
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(18,362,500)	2008	2,298
				14,341
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(11,255,000)	2008-2009	(1,262)
Fixed Swaps/Futures	Gas	(13,120,000)	2008-2009	26,913
				25,651
				$ 39,992

We attempt to maintain balanced positions in our non-trading 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 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 results and financial position, either favorably or unfavorably.

During the nine months ended September 30, 2008 and August 31, 2007, we discontinued the application of hedge accounting in connection with certain derivative financial instruments that were qualified and designated as cash flow hedges related to forecasted sales of natural gas stored in our Bammel storage facilities. The discontinuation resulted from management's determination that the originally forecasted sales of natural gas from the storage facilities were no longer probable of occurring by the end of the originally specified time period, or within an additional two-month period of time thereafter. The determination was made principally due to the unseasonably warm weather that occurred during February through March 2007 for the 2007 period and unfavorable market conditions for the 2008 period. As a result of the discontinued application of hedge accounting, we recognized previously deferred unrealized losses of $10.3 million and unrealized gains of $37.2 million, which are included in the reclassification into earnings from AOCI during the nine months ended September 30, 2008 and August 31, 2007, respectively. We recorded these amounts in cost of products sold in our condensed consolidated statements of operations.

Interest Rate Risk

We are exposed to market risk for changes in interest rates related to our bank credit facilities. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not cash flow hedges are classified in other income.

The following table presents our outstanding interest rate swap derivatives and fair values:

				Fair Value Liability as of	
Term	Notional Amount	Type	Cash Flow Hedge	September 30, 2008	December 31, 2007
March 2009	$125,000	Pay Fixed 5.14% Receive Float	No	$ 945	$ 1,530

We reclassified into earnings, gains of $0.6 million and $1.8 million for the nine months ended September 30, 2008 and August 31, 2007, respectively, related to interest rate swaps that were previously reported in AOCI. We expect gains of $0.3 million to be reclassified into earnings over the next twelve months related to income on interest rate financial instruments currently reported in AOCI. For the three months ended September 30, 2008 and August 31, 2007, we reclassified into earnings, gains of $0.07 million and $0.3 million, respectively, related to interest rate swaps that were previously reported in AOCI.

The following table presents pre-tax balances in AOCI related to interest rate swaps accounted for as cash flow hedges:

				Accumulated Other Comprehensive Income (Loss) as of	
Date Settled	**Term**	**Notional Amount**	**Type**	**September 30, 2008**	**December 31, 2007**
April 2007	2014	$400,000	LIBOR Forward Starting	$ (10,844)	$ (11,135)
June 2006	2016	200,000	Treasury Lock	11,320	12,210
January 2005	2017	100,000	Treasury Lock	(243)	(269)
				$ 233	$ 806

Summary of Derivative Gains and Losses

The following table presents derivative activity recognized in net income:

	Three Months Ended		Nine Months Ended	
	September 30, 2008	**August 31, 2007**	**September 30, 2008**	**August 31, 2007**
Commodity-related				
Unrealized non-trading gains related to commodity related derivatives recognized in cost of products sold, excluding ineffectiveness	$ 41,397	$ 739	$ 6,628	$ 7,442
Ineffective portion of cash flow hedge derivatives recognized in cost of products sold	(11)	(59)	(8,347)	(2,402)
Realized non-trading gains related to commodity-related derivatives included in cost of products sold	42,422	38,665	14,797	186,171
Unrealized trading gains (losses) recognized in revenues	(6,996)	418	(4,117)	(8,194)
Realized trading gains (losses) recognized in revenues	(29,733)	1,077	(24,165)	9,133
Interest rate swaps				
Unrealized gains (losses) on non-hedged interest rate swaps included in other income	$ 1,141	$(16,402)	$ 585	$ 266
Ineffective portion of cash flow derivatives included in interest expense	—	—	—	1,012
Realized gains (losses) on interest rate swaps included in interest expense and other income	(675)	31,808	138	32,499

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.

14. RELATED PARTY TRANSACTIONS:

We made the following sales to and purchases from affiliates of Enterprise G.P. Holdings, L.P. (“Enterprise”):

Enterprise Transactions	Product	Volumes (in thousands)	Dollars
Three Months Ended September 30, 2008:			
Propane Operations -			
Purchases	Propane - gallons	47,336	$ 82,867
Natural Gas Operations -			
Sales	NGLs - gallons	23,362	$ 37,191
	Natural Gas - MMBtu	1,854	17,345
	Fees	—	1,493
Purchases	Natural Gas Imbalances - MMBtu	(1,382)	$ (4,299)
	Natural Gas - MMBtu	5,609	41,726
	Fees	—	13,148
Nine Months Ended September 30, 2008:			
Propane Operations -			
Purchases	Propane - gallons	210,891	$353,451
Natural Gas Operations -			
Sales	NGLs - gallons	39,339	$ 62,104
	Natural Gas - MMBtu	4,886	44,023
	Fees	—	4,651
Purchases	Natural Gas Imbalances - MMBtu	599	$ (1,379)
	Natural Gas - MMBtu	10,938	93,699
	Fees	—	13,660
Period from May 7, 2007 (the date Enterprise became an affiliate) to August 31, 2007:			
Propane Operations -			
Purchases	Propane-gallons	45,490	$ 55,938
Natural Gas Operations -			
Sales	NGLs - gallons	464	$ 648
	Natural Gas - MMBtu	1,495	9,768
Purchases	Natural Gas Imbalances - MMBtu	3,120	$ 22,677
	Natural Gas - MMBtu	1,541	7,501

Accounts receivable from and accounts payable to related companies as of September 30, 2008 and December 31, 2007 relate primarily to activities in the normal course of business.

From time to time, we enter into commodity financial instrument contracts for which Enterprise or its affiliates are the counterparty. During the three and nine months ended September 30, 2008, we recognized losses of $0.7 million and gains of $1.7 million, respectively, in net income. As of September 30, 2008, derivative liabilities with a total fair value of $14.5 million are outstanding with Enterprise from such transactions. Comparative amounts for 2007 were not significant.

ETC OLP 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. During the third quarter of 2008, Enterprise began holding NGL inventory for ETC OLP. The following table summarizes the related party balances with Enterprise on our condensed consolidated balance sheets:

	September 30, 2008	December 31, 2007
Natural Gas Operations:		
Accounts receivable	$ 17,974	$ 9,770
Accounts payable	17,595	6,840
Imbalance payable	4,838	6,218
Inventory	1,646	—
Propane Operations:		
Accounts receivable	$ 1,545	$ 3,396
Accounts payable	18,464	41,939

Accounts receivable from related companies excluding Enterprise consist of the following:

	September 30, 2008	December 31, 2007
ETP GP	$ 123	$ 5,113
ETE	2,438	1,553
MEP	5,011	743
Energy Transfer Technologies, Ltd.	690	922
Others	27	2,941
Total accounts receivable from related companies excluding Enterprise	$ 8,289	$ 11,272

Effective October 19, 2007, the Chief Executive Officer ("CEO") of our General Partner, Mr. Kelcy Warren, voluntarily determined that his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. In accordance with GAAP, we recorded non-cash compensation expense and an offsetting capital contribution of $0.9 million ($0.4 million in salary and $0.5 million in accrued bonuses) for the nine months ended September 30, 2008 as an estimate of the reasonable compensation level for the CEO position.

15. REPORTABLE SEGMENTS:

Our operations include four reportable segments which conduct business exclusively in the United States of America, as follows:

- natural gas operations:
  - midstream
  - intrastate transportation and storage
  - interstate transportation
- retail propane operations

Segments below the quantitative thresholds are classified as "other". The components of the "other" classification have not met any of the quantitative thresholds for determining reportable segments. Management has included the wholesale propane operations in "other" for all periods presented in this report because such operations are not material.

Midstream and intrastate transportation and storage segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general and administrative expenses, gain (loss) on disposal of assets, minority interests, interest expense, earnings (losses) from equity investments and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. We allocate administration expenses from the Partnership to our Operating Partnerships using the Modified Massachusetts Formula Calculation ("MMFC") which is based on factors such as respective segments' gross margins, employee costs, and property and equipment. The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month. The amounts allocated for the periods presented are as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2008	August 31, 2007	September 30, 2008	August 31, 2007
Costs allocated from ETP to Operating Partnerships:				
Midstream and intrastate transportation operations	$ 4,162	$ 4,214	$ 12,747	$ 11,357
Interstate operations	1,200	1,628	3,706	4,388
Propane operations	2,642	3,736	8,167	10,067
Total	$ 8,004	$ 9,578	$ 24,620	$ 25,812
Costs allocated from Operating Partnerships to ETP:				
Midstream and intrastate transportation operations	$ 3,634	$ 938	$ 7,567	$ 5,221
Propane operations	776	577	2,129	2,187
Total	$ 4,410	$ 1,515	$ 9,696	$ 7,408

The following table presents the financial information by segment for the following periods:

	Three Months Ended		Nine Months Ended	
	September 30, 2008	August 31, 2007	September 30, 2008	August 31, 2007
Revenues:				
Midstream	$ 1,435,157	$ 751,989	$ 4,555,340	$ 2,245,313
Eliminations	(1,068,149)	(419,799)	(3,272,574)	(1,205,607)
Intrastate transportation and storage	1,509,555	1,033,031	4,862,641	3,105,079
Interstate transportation	62,023	58,791	176,663	178,663
Retail propane and other retail propane related	263,566	183,628	1,162,941	989,628
All other	4,063	18,686	14,051	90,516
Total revenues	$ 2,206,215	$1,626,326	$ 7,499,062	$ 5,403,592
Cost of Products Sold:				
Midstream	$ 1,352,658	$ 686,942	$ 4,271,788	$ 2,073,469
Eliminations	(1,068,149)	(419,799)	(3,272,574)	(1,205,607)
Intrastate transportation and storage	1,150,799	822,825	3,965,931	2,455,855
Retail propane and other retail propane related	195,403	109,420	761,415	584,284
All other	2,743	18,272	10,684	82,862
Total cost of products sold	$ 1,633,454	$1,217,660	$ 5,737,244	$ 3,990,863

Table of Contents

	Three Months Ended September 30, 2008	Three Months Ended August 31, 2007	Nine Months Ended September 30, 2008	Nine Months Ended August 31, 2007
Depreciation and Amortization:				
Midstream	$ 16,669	$ 6,978	$ 44,004	$ 18,769
Intrastate transportation and storage	23,820	17,369	60,293	43,848
Interstate transportation	9,637	9,077	28,204	27,972
Retail propane and other retail propane related	20,255	18,998	58,828	54,241
All other	127	169	428	523
Total depreciation and amortization	$ 70,508	$ 52,591	$ 191,757	$ 145,353
Operating Income (Loss):				
Midstream	$ 39,862	$ 36,386	$ 157,517	$ 91,607
Intrastate transportation and storage	229,921	129,073	554,140	426,299
Interstate transportation	33,698	27,749	91,414	95,650
Retail propane and other retail propane related	(39,728)	(20,974)	61,705	106,405
All other	(186)	(1,145)	(528)	1,482
Unallocated selling, general and administrative expenses	(3,059)	1,051	(4,425)	367
Total operating income	$ 260,508	$172,140	$ 859,823	$ 721,810
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (67,792)	$ (47,180)	$ (191,757)	$(134,101)
Equity in earnings (losses) of affiliates	(654)	(51)	(749)	274
Gain (loss) on disposal of assets	2,520	(2,525)	1,584	(8,254)
Other, net	19,316	17,154	54,910	36,328
Income tax benefit (expense)	7,150	(3,202)	(8,754)	(10,062)
Minority interests	—	191	—	(888)
	(39,460)	(35,613)	(144,766)	(116,703)
Net income	$ 221,048	$136,527	$ 715,057	$ 605,107

	September 30, 2008	December 31, 2007
Total Assets:		
Midstream	$ 1,523,075	$1,304,187
Intrastate transportation and storage	4,446,923	3,976,895
Interstate transportation	2,381,789	1,834,941
Retail propane and other retail propane related	1,756,820	1,778,426
All other	612,701	113,712
Total	$10,721,308	$9,008,161

	Nine Months Ended September 30, 2008	Nine Months Ended August 31, 2007
Additions to Property, Plant and Equipment including acquisitions (accrual basis):		
Midstream	$ 204,610	$ 141,163
Intrastate transportation and storage	728,028	627,970
Interstate transportation	621,807	1,345,637
Retail propane and other retail propane related	97,602	39,543
All other	1,800	1,513
Total	$ 1,653,847	$2,155,826

Table of Contents

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

(Tabular dollar amounts, except per unit data, 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 our previous fiscal year ended August 31, 2007 filed with the Securities and Exchange Commission ("SEC") on October 30, 2007. 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 for the fiscal year ended August 31, 2007.

Overview

General

Our business activities are primarily conducted through our Operating Partnerships. The Partnership and the Operating Partnerships are sometimes referred to collectively in this report as "we", "us", "Energy Transfer" or "ETP".

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 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 amount 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 acquisitions and business combinations, including the combination of the retail propane operations of Heritage Propane, L.P. and the midstream and intrastate transportation and storage operations of ETC OLP in January 2004. Subsequent to this combination, we have made numerous significant acquisitions in both our natural gas and propane operations, most notably the following:

- ET Fuel System in June 2004
- HPL System in January 2005
- Titan Propane in June 2006
- Transwestern in December 2006
- Canyon Gathering System in October 2007

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. Recently, we announced the construction of the Texas Independence Pipeline to be completed in the third quarter of 2009, as well as the completion of several projects including our Southeast Bossier pipeline in April 2008, and our San Juan Loop, Paris Loop, Maypearl to Malone and Carthage pipelines in the third quarter of 2008.

Our principal operations are primarily conducted in the following reportable segments (see Note 15 to our unaudited condensed consolidated financial statements):

- Midstream - Revenue is primarily dependent upon the volumes of natural gas gathered, compressed, treated, processed, transported, purchased and sold through our pipelines (excluding the transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.
- Intrastate transportation and storage - Revenue is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline on an interruptible basis. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The 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. The use of the Bammel storage reservoir allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin.

- Interstate transportation - The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.
- Retail propane - Revenue is generated from the sale of propane and propane-related products and services.

Our midstream and propane operations are primarily margin-driven businesses, while our intra- and interstate transportation and storage operations are primarily fee-driven businesses. Thus, our results are significantly impacted by the margins we realize and the volumes we sell, transport and store, and to a lesser extent, commodity prices.

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 our previous fiscal year ended August 31, 2007 filed with the SEC on October 30, 2007.

New Developments

ETP Enogex Partners LLC

In September 2008, we entered into an agreement with OGE Energy Corp. (“OGE”) to form a joint venture entity to which OGE would contribute its Enogex midstream business and we would contribute our 100% equity interest in Transwestern Pipeline Company, our 50% equity interest in MEP and 100% of our interests in the Canyon Gathering System. The joint venture entity, ETP Enogex Partners LLC (“ETP Enogex Partners”), will be jointly owned and managed by us and OGE on a 50/50 basis. The parties are contractually obligated to take various actions to facilitate an initial public offering of ETP Enogex Partners as a master limited partnership following the closing of the transaction, including the creation of a master limited partnership structure pursuant to which we and OGE would each own 50% of the general partner entity that would be entitled to receive incentive distribution payments from ETP Enogex Partners.

The completion of the joint venture transaction is subject to obtaining specified financings on satisfactory terms, customary regulatory approvals and various third-party consents. In this regard, the agreement related to this transaction specifies that it is a condition to the obligations of each of us and OGE to consummate the joint venture transaction that ETP Enogex Partners obtain debt financings consisting of (i) the issuance by ETP Enogex Partners of a minimum of $700.0 million of senior notes having a 10-year maturity, (ii) the issuance by Transwestern Pipeline Company of $800.0 million of senior notes having a 10-year maturity and (iii) the arranging of a minimum of $700.0 million revolving credit facility for ETP Enogex Partners, in each case satisfying specified financing terms. If these financings are completed, ETP Enogex Partners would use the proceeds to repay Transwestern Pipeline Company’s existing senior notes and its outstanding indebtedness to ETP, to repay Enogex’s credit facility and its outstanding indebtedness to OGE, and to make a $266.0 million cash distribution to OGE. In such event, we would expect to receive approximately $600.0 million as repayment of the outstanding indebtedness owed to us by Transwestern Pipeline Company, which payment would significantly enhance our capital position.

Enogex operates a pipeline system engaged in natural gas gathering, compression, treating, dehydration, processing, transportation and storage. The Enogex system, located principally in Oklahoma, includes approximately 2,300 miles of natural gas transmission pipe and two storage facilities with total 2007 throughput of 1.52 Bcf/d, connecting to 11 different intrastate and interstate pipelines at 64 interconnection points. The storage fields have working gas capacity of 23 Bcf. Enogex has 175,000 horsepower of transmission compression. The Enogex gathering system has more than 5,534 miles of pipeline with connections to approximately 3,100 wells and 250 central receipt points, plus six active processing plants, with 723 MMcf/d of inlet capacity, and a 50% interest in an additional processing plant with 20 MMcf/d of inlet capacity. Enogex has 225,000 horsepower of owned gathering and processing compression.

Fayetteville Express Pipeline, LLC

In October, 2008, we entered into an agreement with KMP for a 50/50 joint development of Fayetteville Express Pipeline, an approximately 187-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 Quitman County, Mississippi. Fayetteville Express Pipeline, LLC (“FEP”), the entity formed to own and operate this pipeline, plans to initiate public review of the project pursuant to the FERC’s NEPA pre-filing review process in November 2008. The pipeline will have an initial capacity of 2.0 Bcf/d. Pending necessary regulatory approvals, the approximately $1.3 billion pipeline project is expected to be in service by late 2010 or early 2011. FEP has secured binding 10-year commitments 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 Knight, Inc. Knight owns the general partner of KMP.

Trends and Outlook

Current economic conditions make it difficult for companies to obtain funding in either the debt or equity markets. The current constraints in the capital markets may affect our ability to obtain funding through new borrowings or the issuance of Common Units. In addition, we expect that, to the extent we are successful in arranging new debt financing, we will incur increased costs associated with these debt financings. In light of the current market conditions, we have taken steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate at the same level as the prior quarter and continuing to appropriately manage operating and administrative costs to improve profitability. As of September 30, 2008, in addition to $526.1 million of cash on hand, we had available capacity under the ETP Credit Facility of $588.0 million. We expect to utilize these resources, along with cash from operations, to fund a significant portion of our growth capital expenditures and working capital needs during 2009 and, based on the initiatives described above, we do not expect the need to access the capital markets until mid to late 2009 or, if the ETP Enogex Partners transaction is consummated with the currently contemplated financing plan as described above in “New Developments”, until the first half of 2010.

We will continue to evaluate a variety of financing sources in order to fund our growth capital expenditures and working capital needs, including new debt financings and equity offerings. In this regard, we are discussing the possibility of increasing the borrowing capacity under the ETP Credit Facility from $2.0 billion to $3.0 billion, which increase is permitted by the ETP Credit Facility, subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity. In addition, we will continue to pursue financing for the ETP Enogex Partners transaction which, if consummated with the currently contemplated financing as described above, would provide us with approximately $600.0 million of incremental capital. We also intend to pursue obtaining a separate credit facility for FEP to fund construction of the Fayetteville Express Pipeline. Finally, we have initiated discussions with ETE regarding the prospect of ETE purchasing additional equity interests in us as ETE has approximately $350.0 million of cash on hand and available borrowing capacity under its revolving credit facility.

We believe that the size and scope of our operations, our stable asset base and cash flow profile and our investment grade status will be significant positive factors in our efforts to obtain new debt or equity funding; however, there is no assurance that we will be successful in obtaining financing under any of the alternatives discussed above if current capital market conditions continue for an extended period of time or if markets deteriorate further from current conditions. Furthermore, the terms, size and cost of any one of these financing alternatives could be less favorable and could be impacted by the timing and magnitude of our funding requirements, market conditions, and other uncertainties.

Current economic conditions also indicate that many of our customers may encounter increased credit risk in the near term. In particular, our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas and NGLs have fallen dramatically since July 2008. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our customers to announce plans to decrease drilling levels and, in some cases, to consider shutting in natural gas production from some producing wells.

In our intrastate and interstate natural gas operations, a significant portion of our revenue is derived from long-term fee-based arrangements pursuant to which our customers pay us capacity reservation charges regardless of the volume of natural gas transported; however, a portion of our revenue is derived from charges based on actual volumes transported. As a result, our operating cash flows from our natural gas pipeline operations are not tied directly to changes in natural gas and NGL prices; however, the volumes of natural gas we transport may be adversely affected by reduced drilling activity of our customers as a result of lower natural gas prices. As a portion of our pipeline transportation revenue is based on volumes transported, lower volumes of natural gas transported would result in lower revenue from our intrastate and interstate natural gas operations. Based on the significant level of revenue we receive from reservation capacity charges under long-term contracts and our review of the recent announcements of drilling plans by our customers, we do not expect the current level of natural gas prices to have a significant adverse effect on our operating results; however, there are no assurances that commodity prices will not decline further, which could result in a further reduction in drilling activities by our customers.

Since certain of our natural gas marketing operations and substantially all of our propane operations involve the purchase and resale of natural gas and NGLs, we expect our revenues and costs of products sold to be lower than prior periods if commodity prices remain at or fall below existing levels. However, we do not expect our margins from these activities to be significantly impacted as we typically purchase the commodity at a lower price than the sales price. Since the prices of natural gas and NGLs have been volatile, there are no assurances that we will ultimately sell the commodity for a profit.

As noted above, we may reduce our level of discretionary capital expenditures for growth projects in order to preserve our capital resources in the event that the capital market conditions do not allow us to obtain debt or equity financing on reasonable terms. In the event we do not pursue growth projects due to lack of capital, we would likely not achieve the growth in distributable cash flow as we have previously planned.

We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swaps where applicable, and to date have not had any significant credit defaults associated with our transactions. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Results of Operations

In November 2007, we filed a Form 8-K indicating that our Limited Partnership Agreement had been amended to change our fiscal year end to the calendar year. Thus, our current fiscal year began on January 1, 2008. We completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the three and nine-month periods ended September 30, 2008 and the three and nine-month periods ended August 31, 2007 (the three and nine-month periods of the previous fiscal year most nearly comparable to the three and nine-month periods ended September 30, 2008).

We did not recast the financial data for the prior fiscal periods because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Furthermore, we believe the information and data of the three and nine-month periods ended August 31, 2007 is comparable to what would have been reported for the three and nine-month periods ended September 30, 2007 if we had recast the prior period information. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the three and nine-month periods ended August 31, 2007 to the periods ended September 30, 2008 are substantially similar to what would have been reflected had we recast the information for the period ended September 30, 2007.

Historically, the comparability of our condensed consolidated financial statements is affected by fluctuation in natural gas prices, mainly in our producer services' gas sales and purchases and natural gas sales and purchases on our HPL System. Since we buy and sell natural gas primarily based on either first of month index prices, gas daily average prices or a combination of both, our gas sales and purchases tend to be higher when natural gas prices are high and our gas sales and purchases tend to be lower when natural gas prices are lower. However, a change in natural gas prices is only one of several elements that impact our overall margin. Other factors include, but are not limited to, volumetric changes, our hedging strategies and the use of financial instruments, fee-based revenues, trading activities, and basis differences between market hubs.

Due to a high level of market volatility as well as other business considerations, we ceased our speculative trading activities in July 2008. As a result, we will no longer have any material exposure to market risk from these activities. Trading activities resulted in net losses of approximately $26.2 million for the nine months ended September 30, 2008, net gains of approximately $2.2 million for the fiscal year ended August 31, 2007 and net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007.

Consolidated Results

	Three Months Ended September 30, 2008	Three Months Ended August 31, 2007	Change	Nine Months Ended September 30, 2008	Nine Months Ended August 31, 2007	Change
Revenues	$ 2,206,215	$1,626,326	$579,889	$ 7,499,062	$5,403,592	$2,095,470
Cost of products sold	1,633,454	1,217,660	415,794	5,737,244	3,990,863	1,746,381
Gross margin	572,761	408,666	164,095	1,761,818	1,412,729	349,089
Operating expenses	197,493	144,507	52,986	573,606	427,219	146,387
Depreciation and amortization	70,508	52,591	17,917	191,757	145,353	46,404
Selling, general and administrative	44,252	39,428	4,824	136,632	118,347	18,285
Operating income	260,508	172,140	88,368	859,823	721,810	138,013
Interest expense, net of interest capitalized	(67,792)	(47,180)	(20,612)	(191,757)	(134,101)	(57,656)
Equity in earnings (losses) of affiliates	(654)	(51)	(603)	(749)	274	(1,023)
Gain (loss) on disposal of assets	2,520	(2,525)	5,045	1,584	(8,254)	9,838
Other, net	19,316	17,154	2,162	54,910	36,328	18,582
Income tax benefit (expense)	7,150	(3,202)	10,352	(8,754)	(10,062)	1,308
Minority interests	—	191	(191)	—	(888)	888
Net income	$ 221,048	$ 136,527	$ 84,521	$ 715,057	$ 605,107	$ 109,950

See the detailed discussion of revenues, cost of products sold, margin and operating expense by operating segment below.

Interest Expense. For the three and nine months ended September 30, 2008 compared to August 31, 2007, interest expense increased principally due to higher levels of borrowings which increased primarily due to the financing of our growth capital expenditures in our intrastate transportation and storage and interstate transportation operations.

Other, net. The increase between the three month periods is principally due to an increase in AFUDC on equity of $19.7 million offset by a decrease in net gains related to non-hedged interest rate derivatives of $14.7 million.

The increase in other, net between the nine month periods is principally due to an increase in AFUDC on equity of $45.2 million and $7.1 million from the excess of CIAC related to a $40.0 million reimbursement in connection with an extension on our Southeast Bossier pipeline (see Note 2 to our condensed consolidated financial statements). The increase in other, net, was offset by a decrease in net gains related to non-hedged interest rate derivates of $31.8 million.

Income Tax Expense. As a partnership, we are generally not subject to income taxes. However, certain wholly-owned subsidiaries are corporations that are subject to income taxes.

For the three and nine months ended September 30, 2008, the decrease in income tax expense was primarily due to a $12.0 million tax benefit associated with a trading loss incurred by our corporate subsidiaries in July 2008. This tax benefit was offset by higher taxes resulting from increased earnings during the periods. For additional information related to income tax expense, see Note 8 to our condensed consolidated financial statements.

Segment Operating Results

Operating income by segment is as follows:

	Three Months Ended September 30, 2008	Three Months Ended August 31, 2007	Change	Nine Months Ended September 30, 2008	Nine Months Ended August 31, 2007	Change
Midstream	$ 39,862	$ 36,386	$ 3,476	$ 157,517	$ 91,607	$ 65,910
Intrastate transportation and storage	229,921	129,073	100,848	554,140	426,299	127,841
Interstate transportation	33,698	27,749	5,949	91,414	95,650	(4,236)
Retail propane	(39,728)	(20,974)	(18,754)	61,705	106,405	(44,700)
All other	(186)	(1,145)	959	(528)	1,482	(2,010)
Unallocated selling, general and administrative expenses	(3,059)	1,051	(4,110)	(4,425)	367	(4,792)
Total operating income	$ 260,508	$172,140	$ 88,368	$ 859,823	$721,810	$138,013

Midstream

	Three Months Ended			Nine Months Ended		
	September 30, 2008	August 31, 2007	Change	September 30, 2008	August 31, 2007	Change
Volumes:						
Natural gas MMBtu/d - sold	1,344,033	926,511	417,522	1,361,295	930,401	430,894
NGLs Bbls/d - sold	24,019	22,417	1,602	27,618	19,986	7,632
Operating Results:						
Revenues	$ 1,435,157	$ 751,989	$ 683,168	$ 4,555,340	$ 2,245,313	$ 2,310,027
Cost of products sold	1,352,658	686,942	665,716	4,271,788	2,073,469	2,198,319
Gross margin	82,499	65,047	17,452	283,552	171,844	111,708
Operating expenses	16,661	10,558	6,103	50,792	30,261	20,531
Selling, general and administrative	9,307	11,125	(1,818)	31,239	31,207	32
Depreciation and amortization	16,669	6,978	9,691	44,004	18,769	25,235
Segment operating income	$ 39,862	$ 36,386	$ 3,476	$ 157,517	$ 91,607	$ 65,910

Gross Margin. Midstream gross margin increased between the comparable three-month periods primarily due to the following factors:

- An increase in fee-based revenue and processing margin of $17.1 million and $15.2 million, respectively, from our gathering and processing assets (other than our Canyon Gathering System). The increase was due to incremental volumes from the expansion of the Godley plant since placing it into service as well as favorable market conditions to process and extract NGLs;
- Incremental margin of $7.6 million due to the acquisition of the Canyon Gathering System in October 2007; and,
- A net decrease of $22.5 million in margin from our trading and marketing activities. Net realized and unrealized trading losses were $36.7 million for the three months ended September 30, 2008 compared to a net gain of $1.5 million for the three months ended August 31, 2007. As of July 2008 we no longer engage in the trading of financial derivative instruments that are not offset by physical positions. Other marketing activities resulted in a margin of $14.6 million for the three months ended September 30, 2008 compared to a net loss of $1.1 million for the three months ended August 31, 2007. The increase in margin from other marketing activities was due to favorable market conditions, primarily from the Houston Ship Channel market hub to interconnections with interstate markets on our HPL System.

Midstream gross margin increased between the comparable nine-month periods primarily due to the following factors:

- An increase in fee-based revenue and processing margin of $59.1 million and $55.1 million, respectively, from our gathering and processing assets (other than our Canyon Gathering System). The increase was due to incremental volumes from the expansion of the Godley plant since placing it into service as well as favorable market conditions to process and extract NGLs;
- Incremental margin of $20.1 million due to the acquisition of the Canyon Gathering System in October 2007; and,
- A net decrease of $22.6 million in margin from our trading and marketing activities. Net realized and unrealized trading losses were $28.3 million for the nine months ended September 30, 2008 compared to a net gain of $0.9 million for the nine months ended August 31, 2007. As of July 2008, we no longer engage in the trading of financial derivative instruments that are not offset by physical positions. Other marketing activities resulted in a margin of $17.1 million for the nine months ended September 30, 2008 compared to $10.4 million for the nine months ended August 31, 2007.

Operating Expenses. For the three months ended September 30, 2008 compared to August 31, 2007, midstream operating expenses increased primarily due to increased employee-related costs (such as salaries, incentive compensation and healthcare costs) of $2.7 million, increased ad valorem taxes of $0.6 million, increased plant operating expenses of $1.6 million, increased operating overhead of $0.6 million and increased vehicles expense of $0.6 million. These increases were primarily due to the expansion of the Godley plant and the acquisition of the Canyon Gathering System in October 2007.

For the nine months ended September 30, 2008 compared to August 31, 2007, midstream operating expenses increased primarily due to increased employee-related costs of $7.2 million, increased compressor rental expense of $2.3 million, increased plant operating expenses of $3.8 million, increased ad valorem tax of $2.3 million, increased chemicals expense of $1.6 million, increased vehicles expense of $1.4 million, and increases in other expenses of $1.9 million. These increases were primarily due to the expansion of the Godley plant and the acquisition of the Canyon Gathering System in October 2007.

Selling, General and Administrative Expenses. For the three months ended September 30, 2008 compared to August 31, 2007, midstream selling, general and administrative expenses increased primarily due to employee-related costs of $8.2 million offset by a decrease of $5.2 million in allocated legal fees and a decrease of $6.5 million in allocated administrative overhead expenses. Effective January 1, 2008, we began allocating legal costs related to regulatory matters equally between the midstream and transportation and storage segments. During the three and nine month periods ended August 31, 2007, all legal costs related to regulatory matters were recorded in the midstream segment.

For the nine months ended September 30, 2008 compared to August 31, 2007, midstream selling, general and administrative expenses increased primarily due to increased employee-related costs of $10.5 million, an increase of $1.4 million in office expenses offset by a $9.4 million decrease in allocated legal fees (as discussed above) and a $5.4 million decrease in allocated administrative overhead expenses.

Depreciation and Amortization. Midstream depreciation and amortization expense increased during the comparable three and nine month periods primarily due to incremental depreciation related to the Canyon Gathering System acquisition in October 2007 and the continued expansion of the Godley plant.

Intrastate Transportation and Storage

	Three Months Ended			Nine Months Ended		
	September 30, 2008	August 31, 2007	Change	September 30, 2008	August 31, 2007	Change
Volumes:						
Natural gas MMBtu/d - transported	11,613,933	7,787,906	3,826,027	10,515,132	9,288,808	1,226,324
Natural gas MMBtu/d - sold	1,409,348	1,437,598	(28,250)	1,556,524	1,430,869	125,655
Operating Results:						
Revenues	$ 1,509,555	$1,033,031	$ 476,524	$ 4,862,641	$3,105,079	$1,757,562
Cost of products sold	1,150,799	822,825	327,974	3,965,931	2,455,855	1,510,076
Gross margin	358,756	210,206	148,550	896,710	649,224	247,486
Operating expenses	86,332	51,636	34,696	227,026	138,335	88,691
Selling, general and administrative	18,683	12,128	6,555	55,251	40,742	14,509
Depreciation and amortization	23,820	17,369	6,451	60,293	43,848	16,445
Segment operating income	$ 229,921	$ 129,073	$ 100,848	$ 554,140	$ 426,299	$ 127,841

Gross Margin. Intrastate transportation and storage gross margin increased between the comparable three-month periods primarily due to the following factors:

- Transported natural gas volumes increased primarily due to the increased volumes experienced on our ET Fuel and ETC Katy Pipeline systems as a result of increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, increased demand for natural gas to be used by electricity-producing power plants connected to our assets, and the completion of the Southeast Bossier pipeline in April 2008. The increase was also attributed to higher transportation volumes on our Oasis pipeline as a result of favorable market conditions between the Waha and Katy/Houston Ship Channel market hubs. Natural gas sales volumes decreased primarily due to a decrease in withdrawals from our Bammel storage facility. Transportation fees increased approximately $53.8 million for the three months ended September 30, 2008 as compared to the three months ended August 31, 2007. Retention revenue increased approximately $34.9 million due to increased volumes transported through our transportation pipelines;
- Higher natural gas prices resulting in additional retention margin of $18.5 million. Our average natural gas prices for retained fuel increased to $10.33/MMBtu during the three months ended September 30, 2008 from $6.63/MMBtu during the three months ended August 31, 2007;

- Higher margins on natural gas sold on our HPL System and other systems of $4.6 million which increased primarily due to higher natural gas prices;
- An increase in natural gas storage-related margin of $42.3 million. Realized margin, comprised of both margin on the withdrawal and sale of natural gas and realized gains on derivative instruments related to our storage operations, decreased by $4.2 million for the three months ended September 30, 2008 compared to the three months ended August 31, 2007. During the three months ended August 31, 2007, there were physical sales of 26 Bcf of natural gas from our Bammel storage facility whereas during the three months ended September 30, 2008, we made no withdrawals from our storage facility. Thus, the margin realized during the three months ended September 30, 2008, which totaled $23.0 million, was comprised solely of realized gains from derivative instruments. In addition, we recognized unrealized gains related to our storage operations (which represent the change in the fair value of derivative instruments not designated as hedges for accounting purposes) of $47.8 million during the three months ended September 30, 2008. Of the unrealized gains recognized during the current period, $32.8 million relates to derivative instruments (entered into as economic hedges of future withdrawals) that will settle subsequent to September 30, 2008. The amount that we will ultimately realize, however, is subject to change as commodity prices change in future months and the underlying physical transaction occurs.

Intrastate transportation and storage gross margin increased between the comparable nine-month periods primarily due to the following factors:

- Overall volumes on our transportation pipelines were higher due to increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, increased demand for natural gas used by electricity-producing power plants connected to our assets and the completion of the Southeast Bossier pipeline in April 2008. The increase in transport volumes were also due to favorable market conditions between the Waha and Katy/Houston Ship Channel market hubs resulting in higher volumes and higher average rates on our Oasis pipeline. Transportation fees increased approximately $162.2 million for the nine months ended September 30, 2008 as compared to the nine months ended August 31, 2007. Fuel retention revenue increased approximately $79.5 million due to increased volumes transported through our transportation pipelines;
- Higher natural gas prices resulting in additional retention margin of $45.7 million. Our average natural gas prices for retained fuel increased to $10.14/MMBtu during the nine months ended September 30, 2008 from $6.90/MMBtu during the nine months ended August 31, 2007;
- Higher margins on natural gas sold on our HPL System and other systems of $21.4 million which increased primarily due to higher natural gas prices; and,
- A decrease in natural gas storage-related margin of $68.3 million. Realized margin, comprised of both margin on the withdrawal and sale of natural gas and realized gains on derivative instruments related to our storage operations, decreased by $97.9 million for the nine months ended September 30, 2008 compared to the nine months ended August 31, 2007. During the nine months ended September 30, 2008, there were physical sales of 36 Bcf of natural gas from our Bammel storage facility compared to 67 Bcf in the 2007 period. In addition, between the two periods, there was an increase of $8.2 million in storage fees, primarily due to a new contract that commenced on April 1, 2007 at our Bammel storage facility. Furthermore, we recognized unrealized gains related to our storage operations (which represent the change in the fair value of derivative instruments not designated as hedges for accounting purposes) of $23.1 million during the nine months ended September 30, 2008. Of the unrealized gains recognized during the current period, $32.8 million relates to derivative instruments (entered into as economic hedges of future withdrawals) that will settle subsequent to September 30, 2008. The amount that we will ultimately realize, however, is subject to change as commodity prices change in future months and the underlying physical transaction occurs.

Operating Expenses. For the three months ended September 30, 2008 compared to August 31, 2007, intrastate transportation and storage operating expenses increased primarily due to increased fuel consumption of $33.2 million, increased employee costs of $1.3 million, and increased ad valorem taxes of $1.7 million. The increase in fuel consumption was due to increased transport volumes and higher natural gas prices. In addition, we now own much of our own compression which was previously leased from third parties. This led to increases of $1.2 million in compressor maintenance and $2.0 million in utilities. These increases were offset by a $2.4 million decrease in compressor rentals and a $1.8 million decrease in measurement expense and professional fees.

For the nine months ended September 30, 2008 compared to August 31, 2007, intrastate transportation and storage operating expenses increased primarily due to increased fuel consumption of $84.0 million, increased employee costs of $5.4 million, and increased ad valorem taxes of $3.7 million. The increase in fuel consumption was due to increased transport volumes and higher natural gas prices. In addition, we now own much of our own compression which was previously leased from third parties. This led to increases of $4.6 million in compressor maintenance and $4.6 million in utilities. These increases were offset by an $8.0 million decrease in compressor rentals, and a $4.2 million decrease in measurement expense and professional fees.

Selling, General and Administrative Expenses. For the three months ended September 30, 2008 compared to August 31, 2007, intrastate transportation and storage selling, general and administrative expenses increased primarily due to an increase of $2.4 million in allocated legal fees and an increase in certain departmental costs allocated from the midstream segment of $3.7 million. Effective January 1, 2008, we began allocating legal costs related to regulatory matters equally between the midstream and transportation and storage segments. During the three and nine month periods ended August 31, 2007, all legal costs related to regulatory matters were recorded in the midstream segment.

For the nine months ended September 30, 2008 compared to August 31, 2007, intrastate transportation and storage selling, general and administrative expenses increased primarily due to an increase of $9.2 million in allocated legal fees (as discussed above) and an increase in certain departmental costs allocated from the midstream segment of $5.4 million.

Depreciation and Amortization. For the three and nine months ended September 30, 2008 compared to August 31, 2007, intrastate transportation and storage depreciation and amortization expense increased primarily due to the continuing expansion of our pipeline system, most notably the Southeast Bossier and Maypearl to Malone pipelines.

For the nine months ended September 30, 2008 compared to August 31, 2007, intrastate transportation and storage depreciation and amortization expense increased principally due to the continuing expansion of our pipeline system, most notably the Cleburne to Carthage, Southeast Bossier and Maypearl to Malone pipelines.

Interstate Transportation

	Three Months Ended			Nine Months Ended		
	September 30, 2008	August 31, 2007	Change	September 30, 2008	August 31, 2007	Change
Volumes:						
Natural gas MMBtu/d -transported	1,862,781	1,874,179	(11,398)	1,750,592	1,802,109	(51,517)
Operating Results:						
Revenues	$ 62,023	$ 58,791	$ 3,232	$ 176,663	$ 178,663	$ (2,000)
Operating expenses	13,278	14,615	(1,337)	39,128	36,295	2,833
Selling, general and administrative	5,410	7,350	(1,940)	17,917	18,746	(829)
Depreciation and amortization	9,637	9,077	560	28,204	27,972	232
Segment operating income	$ 33,698	$ 27,749	$ 5,949	$ 91,414	$ 95,650	$ (4,236)

Volumes. The decrease in natural gas transported was principally due to unfavorable pricing at the San Juan and Permian market hubs resulting in lower transportation volumes on the eastern portion of our pipeline offset by increased demand from our western markets for both the three-month and nine-month periods.

Revenues. For the three months ended September 30, 2008 compared to August 31, 2007, revenues increased due to re-marketing of capacity that had previously been reserved for the Phoenix project, which is not yet completed.

For the nine months ended September 30, 2008 compared to August 31, 2007, revenues decreased due to $5.6 million in lower retained volumes as a result of the implementation of the new tariff rate case settlement commencing on April 1, 2007, offset by a $3.2 million increase in transport revenue due to re-marketing of capacity that had been previously reserved for the Phoenix project, which is not yet completed, and a $0.4 million increase in interruptible transportation revenues.

Operating Expenses. For the three months ended September 30, 2008 compared to August 31, 2007, operating expenses decreased primarily due to $2.3 million of gas balancing activities offset by $0.8 million higher electricity demand and other operating expenses.

For the nine months ended September 30, 2008 compared to August 31, 2007, operating expenses increased primarily due to $3.3 million of gas balancing activities, $0.8 million higher electricity demand and $0.2 million in other operating expenses, offset by $1.6 million primarily due to lower ad valorem taxes.

Selling, General and Administrative Expenses. For the three months ended September 30, 2008 compared to August 31, 2007, selling, general and administrative expenses decreased primarily due to an increase in the allocation of such expenses to capital projects and lower corporate services costs.

For the nine months ended September 30, 2008 compared to August 31, 2007, selling, general and administrative expenses decreased primarily due to an increase in the allocation of expenses to capital projects and lower corporate services costs offset by increases in incentive compensation.

Retail Propane

	Three Months Ended			Nine Months Ended		
	September 30, 2008	August 31, 2007	Change	September 30, 2008	August 31, 2007	Change
Volumes:						
Retail propane gallons sold (in thousands)	90,386	82,311	8,075	422,109	463,638	(41,529)
Operating Results:						
Retail propane revenues	$ 238,830	$161,147	$ 77,683	$1,086,417	$912,983	$173,434
Other retail propane related revenues	24,736	22,481	2,255	76,524	76,645	(121)
Retail propane cost of products sold	187,799	103,784	84,015	744,316	566,585	177,731
Other retail propane related cost of products sold	7,604	5,636	1,968	17,099	17,699	(600)
Gross margin	68,163	74,208	(6,045)	401,526	405,344	(3,818)
Operating expenses	79,843	66,710	13,133	253,193	218,481	34,712
Selling, general and administrative	7,793	9,474	(1,681)	27,800	26,217	1,583
Depreciation and amortization	20,255	18,998	1,257	58,828	54,241	4,587
Segment operating income (loss)	$ (39,728)	$ (20,974)	$(18,754)	$ 61,705	$106,405	$ (44,700)

Volumes. The increase in gallons sold for the three months ended September 30, 2008 compared to the three months ended August 31, 2007, was primarily due to the seasonality impact of the difference in the months included in the respective periods. The month of September (which is included in the three months ended September 30, 2008, but not the comparative 2007 period) is typically the start of the heating season, whereas June (which is included in the three months ended August 31, 2007) is not in the heating season. Total retail propane gallons sold for the nine month period ended September 30, 2008 decreased primarily due to the seasonality impact of the difference in the months included in the respective periods as the nine months ended August 31, 2007 included the month of December, a seasonally higher propane demand month, whereas the nine months ended September 30, 2008 did not include the month of December but rather the month of September, a seasonally lower propane demand month as compared to December.

Outside of the one month heating season impact, retail propane sales volumes remain comparable to the previous period, reflecting increases due to acquisitions completed after August 31, 2007 that were offset by decreases due to customer conservation resulting from rising fuel costs and the slow down in growth from new home construction in our propane markets.

Revenues. The variances between the three and nine months ended September 30, 2008 as compared to the three and nine months ended August 31, 2007 were impacted by the one month difference in the fiscal periods as described above. Retail propane revenues increased on a year over year comparison mainly due to increased sale prices driven by the increased cost of fuel. The average sales price per retail gallons sold increased approximately 35% and 31% for the three and nine month periods ended September 30, 2008, respectively, over the comparable period last year. Historically, as the weather becomes colder, the sales volumes and revenues would typically increase. For the nine months ended September 30, 2008 the weather was slightly colder than normal, but volume trends did not track as closely to weather pattern trends in 2008 due to the slow down in new home construction and the increased fuel prices that caused customer conservation.

Cost of Products Sold. Retail propane cost of products sold increased significantly due to the increased fuel prices experienced through the 2008 periods. Excluding the one month difference in the fiscal periods as described above, our overall cost of fuel for the periods presented represented the major factor in the increased cost of products sold. On average, fuel costs were approximately 65%, or $0.82/gallon, higher during the three months ended September 30, 2008 as compared to the three months ended August 31, 2007 and 44%, or $0.54/gallon, higher during the nine months ended September 30, 2008 as compared to the nine months ended August 31, 2007. The wholesale market price from one of our major supply points, Mt. Belvieu, Texas averaged $1.21 per gallon in 2007, as compared to the current average thus far in 2008, of $1.57 per gallon. The propane operations enter into propane sales commitments with a portion of their retail customers that provide for a contracted price agreement for a specified period of time. These commitments can expose the operations to product price risk if not offset by a propane purchase commitment. The propane operations use financial instruments (swap agreements) to lock in the margins on a portion of these sale commitments. These financial instruments are not designated as hedges for accounting purposes, and the change in market value is recorded in cost of products sold in the condensed consolidated statement of operations. The cost of products sold for the propane operations was negatively impacted by the recent decline in propane prices. Unrealized losses of $21.7 million and $18.4 million were recorded through cost of products sold during the three months and nine months ended September 30, 2008, respectively, on these financial instruments.

Gross Margin. Gross margins reflect the seasonality impact of the one month difference between the comparative periods presented, as discussed above and the unrealized losses on financial instruments. The decrease in gross margin for the 2008 periods presented, as compared to the 2007 periods presented due to the seasonality impact as described above is offset by the impact of higher prices described above. Period over period, retail fuel gross margins were $0.13/gallon lower in the three months ended September 30, 2008 as compared to the three months ended August 31, 2007 primarily due to the accounting impact of the unrealized losses recorded on financial instruments as noted above. For the nine months ended September 30, 2008, gross margins were approximately $0.06/gallon higher than the nine months ended August 31, 2007. The propane operations were able to sustain strong margins throughout the nine months ended September 30, 2008 to compensate for the customer conservation driven by the increased fuel costs.

Operating Expenses. Operating expenses increased for the 2008 periods presented over the comparable periods last year mainly due to higher vehicle fuel costs and other vehicle expenses and increased employee wages and benefits mainly due to acquisitions completed subsequent to August 31, 2007.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses between the comparable periods was primarily due to increased administrative expense allocations, consulting and other costs related to information technology systems implementations and non-recurring costs related to property settlements in 2008.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense between the comparable periods was primarily due to the incremental expense resulting from assets acquired subsequent to August 31, 2007.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our partners 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.

Future capital requirements of our business, excluding any potential changes that could occur if the ETP Enogex Partners transaction is consummated, are expected to consist of:

- maintenance capital expenditures for the intrastate, interstate operations and propane, which include (i) capital expenditures for our intrastate operations for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets, for which we expect to expend approximately $25.3 million during the remainder of the year and (ii) 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, for which we expect to expend approximately $16.0 million during the remainder of the year;
- growth capital expenditures for our intrastate and propane operations mainly for constructing new pipelines, processing plants, treating plants and compression for the intrastate operations for which we expect to expend between $200.0 million and $215.0 million during the remainder of 2008 and between $450.0 million and $475.0 million in 2009 and approximately $12.8 million for customer propane tanks during the remainder of the year;

- growth capital expenditures, excluding capital contributions to the MEP and FEP projects as discussed below, for constructing new pipelines and pipeline expansions for our interstate operations, for which we expect to spend between $115.0 million and $130.0 million for the remainder of 2008 and between $110.0 million and $125.0 million in 2009 (which amounts take into account higher construction cost estimates for Transwestern's Phoenix project);
- capital contributions to fund our pro rata portion of the growth capital expenditures of MEP and FEP (treated as equity method investees for accounting purposes);
  - With respect to our share of the MEP project, capital expenditures are being funded under a project financing arrangement. Therefore, our cash requirements for the MEP project are limited to any capital contributions that we are required to make. We expect to make no capital contributions during the remainder of 2008 and between $230.0 million and $250.0 million during 2009. In October 2008, we announced our entry into the FEP project, as discussed in Note 3 of our consolidated financial statements. FEP intends to pursue separate financing for this project; however, the availability of such financing is uncertain. Excluding project financing, we expect that our capital contributions to the FEP project would be between $190.0 million and $210.0 million in 2009.
- acquisition capital expenditures, including acquisition of new pipeline systems and propane operations.

We generally fund our capital expenditures 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.

Current economic conditions make it difficult to obtain funding in either the debt or equity markets. The current constraints in the capital markets may affect our ability to obtain funding through new borrowings or the issuance of Common Units. In addition, we expect that, to the extent we are successful in arranging new debt financing, we will incur increased costs associated with these debt financings. In light of the current market conditions, we have taken steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate at the same level as the prior quarter and continuing to appropriately manage operating and administrative costs to improve profitability. As of September 30, 2008, in addition to $526.1 million of cash on hand, we had available capacity under the ETP Credit Facility of $588.0 million. We expect to utilize these resources, along with cash from operations, to fund a significant portion of our growth capital expenditures and working capital needs during 2009 and, based on the initiatives described above, we do not expect the need to access the capital markets until mid to late 2009 or, if the ETP Enogex Partners transaction is consummated with the currently contemplated financing plan as described above in "New Developments", until the first half of 2010.

We will continue to evaluate a variety of financing sources in order to fund our growth capital expenditures and working capital needs, including new debt financings and equity offerings. In this regard, we are discussing the possibility of increasing the borrowing capacity under the ETP Credit Facility from $2.0 billion to $3.0 billion, which increase is permitted by the ETP Credit Facility, subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity. In addition, we will continue to pursue financing for the ETP Enogex Partners transaction which, if consummated with the currently contemplated financing as described above, would provide us with approximately $600.0 million of incremental capital. We also intend to pursue obtaining a separate credit facility for FEP to fund construction of the Fayetteville Express Pipeline. Finally, we have initiated discussions with ETE regarding the prospect of ETE purchasing additional equity interests in us as ETE has approximately $350.0 million of cash on hand and available borrowing capacity under its revolving credit facility.

We believe that the size and scope of our operations, our stable asset base and cash flow profile and our investment grade status will be significant positive factors in our efforts to obtain new debt and equity funding; however, there is no assurance that we will be successful in obtaining financing under any of the alternatives discussed above if current capital market conditions continue for an extended period of time or if markets deteriorate further from current conditions. Furthermore, the terms, size and cost of any one of these financing alternatives could be less favorable and could be impacted by the timing and magnitude of our funding requirements, market conditions, and other uncertainties.

The assets used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures other than those expenditures necessary to maintain the service capacity of our existing assets. The assets utilized in our propane operations do not typically require lengthy manufacturing process time or complicated, high technology components. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, replacing pipe caused by delays from mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors into our anticipated growth capital expenditures for each year.

We manage our exposure to increased pipe costs by purchasing steel and reserving mill space, as projects are approved, in advance of construction. However, there is no assurance that we will not be impacted by increased pipe costs and limited mill space.

We engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. Natural gas is typically purchased and held in storage during the summer months and sold during the winter months. Although we intend to fund natural gas purchases with cash generated from operations, from time to time we may need to finance the purchase of natural gas to be held in storage with borrowings from our current credit facilities. We intend to repay these borrowings with cash generated from operations when the gas is sold.

Cash Flows

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

Operating Activities. Cash provided by operating activities during the nine months ended September 30, 2008, was $1.0 billion as compared to cash provided by operating activities of $938.3 million for the nine months ended August 31, 2007. The difference between net income and the net cash provided by operations for the nine months ended September 30, 2008 consisted of non-cash charges of $215.4 million, (principally depreciation and amortization and unit-based compensation expense) and changes in operating assets and liabilities of $92.2 million. Various components of operating assets and liabilities changed significantly from the prior period including factors such as the timing of accounts receivable collections, payments on accounts payable, the timing of the purchase and sale of propane and natural gas inventories, and the timing of advances and deposits received from customers.

Investing Activities. Cash used in investing activities during the nine months ended September 30, 2008 of $1.5 billion was comprised primarily of cash paid for acquisitions of $62.0 million and $1.5 billion invested for growth capital expenditures (net of contribution in aid of construction costs as discussed in Note 2 to our condensed consolidated financial statements), including changes in accruals of $119.2 million. Total growth capital expenditures consist of $889.7 million for our intrastate operations, $608.3 million for our interstate operations, and $34.5 million for our propane operations. We also incurred $75.9 million in maintenance expenditures needed to sustain operations of which $43.0 million related to intrastate operations, $13.5 million related to interstate operations, and $19.4 million related to propane operations. The above expenditures were offset by a $63.5 million net reimbursement during the first quarter of 2008 from MEP to the Partnership for previous advances to MEP.

Financing Activities. Cash provided by financing activities was $914.4 million for the nine months ended September 30, 2008. We received $373.0 million in net proceeds from equity offerings (see Note 11 to our condensed consolidated financial statements). Proceeds from the equity offerings were used to repay borrowings from the ETP Credit Facility. We also received net proceeds of $1.48 billion from the issuance of new ETP Senior Notes (see Note 10 to our condensed consolidated financial statements) which were used to repay other indebtedness. During the nine months ended September 30, 2008, we had a net increase in our debt level of $1.2 billion primarily to fund our growth capital expenditures and for general partnership purposes. During the nine months ended September 30, 2008, we paid distributions of $663.2 million to our partners related to the four-month transition period ended December 31, 2007 and the quarters ended March 31, 2008, and June 30, 2008.

In order to ensure the availability of sufficient cash to fund our announced projects during the near term, we drew approximately $500.0 million on our existing credit facility in September 2008.

Financing and Sources of Liquidity

On January 8, 2008, we issued 750,000 Common Units at $48.81 per Common Unit to underwriters pursuant to the exercise of a 30-day option to purchase Common Units to cover Over-Allotments in connection with a public offering of 5,000,000 of our Common Units representing limited partner interests. The proceeds of $35.0 million, net of offering costs, were used to repay borrowings from the ETP Credit Facility (defined below).

In March 2008, we issued a total of $1.5 billion aggregate principal amount of Senior Notes comprised of $350.0 million of 6.00% Senior Notes due 2013, $600.0 million of 6.70% Senior Notes due 2018, and $550.0 million of 7.50% Senior Notes due 2038 (collectively, the “ETP 2008 Senior Notes”). Interest on the ETP 2008 Senior Notes is payable semiannually on January 1 and July 1 of each year. The Partnership may redeem some or all of the ETP 2008 Senior Notes at any time, or from time to time, pursuant to the terms of the indenture. We used the proceeds of approximately $1.48 billion (net of bond discounts of $8.2 million and other offering costs of $10.8 million) from the issuance of the ETP 2008 Senior Notes to repay other indebtedness.

On July 21, 2008, we issued 7,750,000 Common Units representing limited partner interests at $39.45 per Common Unit in connection with a public offering. We also granted the underwriters a 30-day option to purchase up to an aggregate of 1,162,500 additional Common Units (“Over-Allotment”), which was immediately exercised with the equity issuance. Net proceeds of approximately $338.0 million from the offering and Over-Allotment were used to repay a portion of the amount outstanding under the ETP Revolving Credit Facility. We received $7.2 million related to the capital contribution from our general partner to maintain its 2% general partner’s interest in September 2008.

During 2006, we filed a Registration Statement on Form S-3 with the SEC to register a $1.0 billion aggregate offering price of our Common Units that may be offered for sale by us from time to time. In December 2007, we filed a Registration Statement on Form S-3 with the SEC to register an unspecified quantity of Common Units and an unspecified dollar amount of debt securities, in each case that may be offered for sale by us from time to time.

Description of Indebtedness

Our indebtedness as of September 30, 2008 consisted of $350.0 million in principal amount of 6.00% Senior Notes due 2013, $600.0 million in principal amount of 6.70% Senior Notes due 2018, $550.0 million in principal amount of 7.50% Senior Notes due 2038, $750.0 million in principal amount of 5.95% Senior Notes due 2015, $400.0 million in principal amount of 5.65% Senior Notes due 2012, $400.0 million in principal amount of 6.125% Senior Notes due 2017 and $400.0 million in principal amount of 6.625% Senior Notes due 2036 (collectively, the “ETP Senior Notes”), and a revolving credit facility that allows for borrowings of up to $2.0 billion (expandable to $3.0 billion) available through June 20, 2012 (the “ETP Credit Facility”). We also currently have separate indebtedness at Transwestern and HOLP.

ETP Credit Facility

The ETP Credit Facility is a $2.0 billion revolving credit facility 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) which 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 a rate based on either a Eurodollar rate or a prime rate.

As of September 30, 2008, there was a balance of $1.39 billion outstanding under the ETP Credit Facility. The weighted average interest rate on the total amount outstanding at September 30, 2008, was 3.36%. The total amount available under the ETP Credit Facility, as of September 30, 2008, which is reduced by any outstanding letters of credit, was approximately $588.0 million. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership’s subsidiaries and has equal rights to holders of our other current and future unsecured debt.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the “HOLP Credit Facility”) is 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. As of September 30, 2008, there was $10.0 million outstanding on the revolving credit loans. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Credit Facility. There were outstanding letters of credit of $1.0 million at September 30, 2008. The sum of the loans made under the HOLP Credit Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Credit Facility. The amount available at September 30, 2008 was $64.0 million.

Other

On February 29, 2008, MEP entered into a credit agreement that provides for a $1.4 billion senior revolving credit facility (the “MEP Facility”). We have guaranteed 50% of the obligations of MEP under the MEP Facility, with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is available through 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 also has a swingline loan option with a maximum borrowing of $25.0 million at a prime rate. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit available under the MEP Facility. The indebtedness under the MEP Facility is prepayable at any time at the option of MEP without penalty. 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. The MEP Facility is syndicated among multiple financial institutions; the Royal Bank of Scotland PLC is the administrative agent. Among the lending banks that make up the syndicate of financial institutions for the MEP Facility, affiliates of Lehman Brothers provide less than 10% of the $1.4 billion available. MEP expects the MEP Facility to be reduced by the amount of the Lehman Brothers affiliates’ commitment. However, the MEP Facility is not defaulted, and the commitments of the other lending banks remain unchanged.

In March 2008, MEP reimbursed ETP a net $63.5 million from the MEP Facility for previous advances ETP made to MEP. As of September 30, 2008, MEP had $525.0 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. The weighted average interest rate on the total amount outstanding as of September 30, 2008 was 3.55%. The total amount available under the MEP Facility was $841.7 million as of September 30, 2008. MEP incurred $482.0 million in expenditures related to this project during the nine months ended September 30, 2008, and $577.2 million since inception.

Prior to September 30, 2008, MEP also had a $197.0 million reimbursement agreement under which MEP could issue letters of credit. This reimbursement agreement expired on September 30, 2008 and there are no longer any letters of credit outstanding.

Cash Distributions

We use cash provided by operating and financing activities from the Operating Partnerships to provide distributions to our Unitholders as well as to our General Partner in respect of its 2% general partner interest and its Incentive Distribution Rights. Under the Partnership Agreement, we will distribute to our partners within 45 days after the end of each fiscal quarter, an amount equal to all of our Available Cash 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 General Partner's incentive distributions rights entitle it to receive incentive distributions to the extent that quarterly distributions to our Unitholders exceed $0.275 per unit (which amount represents $1.10 per unit on an annualized basis).

On February 14, 2008, we paid a one-time distribution for the four-month period ended December 31, 2007 of $1.125 per Common Unit ($3.375 per Limited Partner Unit on an annualized basis) to Unitholders of record at the close of business on February 1, 2008.

On May 15, 2008, we paid a per unit cash distribution for the three months ended March 31, 2008 of $0.86875 ($3.475 per Limited Partner Unit annualized) to Unitholders of record at the close of business on May 5, 2008 (a $0.10 increase from the previous distribution per Limited Partner Unit).

On August 14, 2008, we paid a per unit cash distribution of $0.89375 ($3.575 per Limited Partner Unit annualized) for the three months ended June 30, 2008, to Unitholders of record at the close of business on August 7, 2008 (a $0.10 increase per Limited Partner Unit on an annualized basis from the previous distribution).

On October 31 2008, we declared a per unit cash distribution of $0.89375 ($3.575 per Limited Partner Unit annualized) for the three months ended September 30, 2008, which will be paid on November 14, 2008 to Unitholders of record as of the close of business on November 10, 2008.

New Accounting Standards

See Note 2 to our condensed consolidated financial statements.

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 August 31, 2007, 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.

As discussed in Note 13 to our condensed consolidated financial statements, the Partnership ceased certain trading operations in July 2008.

Our commodity-related price risk management assets and liabilities as of September 30, 2008 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	44,577,500	2008-2011	$ (4,670)
Swing Swaps IFERC	Gas	(15,631,000)	2008-2009	4,035
Fixed Swaps/Futures	Gas	(14,722,500)	2008-2010	34,381
Forward Physical Contracts	Gas	122,000	2008	16
Options	Gas	(122,000)	2008	(16)
Forwards/Swaps—in Gallons	Propane	55,440,000	2008-2009	(15,075)
				18,671
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	—	2008-2009	(1,819)
				16,852
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(5,910,000)	2008-2009	8
Fixed Swaps/Futures	Gas	(5,910,000)	2008-2009	13,265
				13,273
				$ 30,125

Credit Risk

We maintain credit policies with regard to our counterparties that we believe significantly minimize 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 ("LDCs"). 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. For additional discussion of our credit risks, see Item 1A. "Risk Factors."

Sensitivity Analysis

The table below summarizes our commodity-related financial derivative instruments and fair values as of September 30, 2008. It also assumes a hypothetical 10% change in the underlying price of the commodity and its effect.

	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Non-Trading Derivatives			
Basis Swaps IFERC/NYMEX	38,667,500	$ (4,663)	$ 2,685
Swing Swaps IFERC	(15,631,000)	4,035	1,189
Fixed Swaps/Futures	(20,632,500)	47,646	17,074
Forward Physical Contracts	122,000	16	11
Options	(122,000)	(16)	11
Forwards/Swaps—in Gallons	55,440,000	(15,075)	7,912
Trading Derivatives:			
Basis Swaps IFERC/NYMEX	—	(1,819)	—

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 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 our condensed consolidated results of operations or in accumulated 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

We are exposed to market risk for increases in interest rates, primarily as a result of our variable rate debt and, in particular, our bank credit facilities. To the extent interest rates increase, our interest expense for our revolving credit facilities will also increase. At September 30, 2008, we had $1.4 billion of variable rate debt outstanding and a pay fixed receive float interest rate swap with a notional amount of $125.0 million that is not designated as a hedge. Changes in fair value of the swap are recorded in other income on the condensed consolidated statements of operations. A hypothetical change of 100 basis points in the underlying interest rate and a corresponding parallel shift in the LIBOR yield curve would have a net effect of $13.6 million in interest expense and other income, in the aggregate, on an annual basis.

We are also subject to interest rate risk on our fixed rate debt if interest rates decrease. To manage this risk, we may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt. For further information, see Note 13 to our condensed consolidated financial statements.

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, as amended ("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, 2008 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 and Principal Financial Officers 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 or Rule 15d 15(f) of the Exchange Act) during the three months ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for our previous fiscal year ended August 31, 2007 and Note 12—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 Form 10-Q for the nine-months ended September 30, 2008.

ITEM 1A. RISK FACTORS

The risks described below supplement the risk factors described in Part 1, Item 1A in our Report on Form 10-K for our previous fiscal year ended August 31, 2007.

We may not be able to obtain funding, obtain funding on acceptable terms or obtain funding under our revolving credit facility because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile due to a variety of factors, including significant write-offs in the financial services sector and the current weak economic conditions.

As a result, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations.

Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be required to post collateral to support our obligations. Moreover, without adequate funding, we may be unable to execute our growth strategy, complete future acquisitions or announced and future pipeline construction projects, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Completion of pipeline expansion projects will require significant amounts of debt and equity financing which may not be available to us on acceptable terms, or at all.

We plan to fund our expansion capital expenditures, including any future pipeline expansion projects we may undertake, with proceeds from sales of our senior notes and common units and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our senior notes and common units on terms satisfactory to us, or at all. In addition, we may be unable to obtain adequate funding under our current revolving credit facility because our lending counterparties may be unwilling or unable to meet their funding obligations.

As of September 30, 2008, we had approximately $5.6 billion of consolidated debt outstanding. A significant increase in our indebtedness, or an increase in our indebtedness that is proportionately greater than our issuances of equity, could negatively impact our credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement, which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

Many of our customers' drilling activity levels and spending for transportation on our pipeline system may be impacted by the current deterioration in the credit markets.

Many of our customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our customers' equity values have substantially declined. The combination of a reduction of cash flow resulting from recent declines in natural gas prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' spending for natural gas drilling activity, which could result in lower volumes being transported on our pipeline system. For example, a number of our customers have announced reduced drilling capital expenditure budgets for the remainder of 2008 and 2009. A significant reduction in drilling activity could have a material adverse effect on our operations.

We are exposed to the credit risk of our customers, and an increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our unitholders.

The risks of nonpayment and nonperformance by our customers are a major concern in our business. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. The current tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment and nonperformance by our customers. Any substantial increase in the nonpayment and nonperformance by our customers could reduce have a material adverse effect on our results of operations and operating cash flows.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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
(54)	2.1	Contribution Agreement dated as of September 22, 2008 by and among Energy Transfer Partners, L.P. and OGE Energy Corp.
(1)	3.1	Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(8)	3.1.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(13)	3.1.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(18)	3.1.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(18)	3.1.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(27)	3.1.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(28)	3.1.8	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(39)	3.1.9	Amendment No. 9 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(37)	3.1.10	Amendment No. 10 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(48)	3.1.11	Amended and Restated Amendment No. 11 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(53)	3.1.12	Amendment No. 12 to the Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(1)	3.2	Agreement of Limited Partnership of Heritage Operating, L.P.
(10)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(16)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(15)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.

	Exhibit Number	Description
(45)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(45)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(17)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.
(18)	4.2	Unitholder Rights Agreement dated January 20, 2004 among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and La Grange Energy, L.P.
(22)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(23)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(29)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(24)	4.7	Registration Rights Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(30)	4.8	Joinder to Registration Rights Agreement, dated February 24, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(31)	4.9	Third Supplemental Indenture dated as of July 29, 2005 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(32)	4.10	Registration Rights Agreement, dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers thereto.
(33)	4.11	Form of Senior Indenture of Energy Transfer Partners, L.P.
(33)	4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P.
(43)	4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(34)	4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(37)	4.15	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(52)	4.16	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(46)	10.1	Amended and Restated Credit Agreement, dated July 20, 2007, among Energy Transfer Partners, L.P., the borrower and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC as senior managing agents, and other lenders party hereto.
(1)	10.2	Form of Note Purchase Agreement (June 25, 1996).
(2)	10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.
(3)	10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.

Table of Contents

		Exhibit Number	Description
(5)		10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.
(6)		10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
(7)		10.2.5	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(8)		10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(11)		10.2.7	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(15)	**	10.6.3	Second Amended and Restated Restricted Unit Plan dated as of February 4, 2002.
(49)		10.6.5	Form of Grant Agreement.
(50)		10.6.6	Amended and Restated 2004 Unit Plan.
(51)	**	10.6.7	Midstream Bonus Plan.
(4)		10.16	Note Purchase Agreement dated as of November 19, 1997.
(5)		10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement.
(6)		10.16.2	Second Amendment Agreement dated September 1, 1999 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(7)		10.16.3	Third Amendment Agreement dated May 31, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(8)		10.16.4	Fourth Amendment Agreement dated August 10, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(11)		10.16.5	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(19)		10.16.6	Sixth Amendment Agreement dated as of November 18, 2003 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(8)		10.19	Note Purchase Agreement dated as of August 10, 2000.
(11)		10.19.1	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(12)		10.19.2	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to the August 10, 2000 Note Purchase Agreement.
(19)		10.19.3	Sixth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(25)		10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers and La Grange Acquisition, L.P., as Buyer.
(26)		10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(43)	**	10.45	Summary of Director Compensation.

Table of Contents

	Exhibit Number	Description
(40)	10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.
(41)	10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
(42)	10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
(46)	10.54	Fourth Amended and Restated Credit Agreement dated as of August 31, 2006 between and among Heritage Operating L.P., as the Borrower, and the Banks now or hereafter signatory parties hereto, as lenders "Banks" and Bank of Oklahoma, National Association as administrative agent and joint lead arranger for the Banks, JPMorgan Chase Bank, N.A., as syndication agent for the Banks, and J.P. Morgan Securities Inc., as joint lead arranger for the Banks.
(45)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(45)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(45)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(47)	21.1	List of Subsidiaries.
(*)	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.

---

* Filed herewith.

** Denotes a management contract or compensatory plan or arrangement.

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

(2) Incorporated by reference to the same numbered Exhibit to Registrant's Form 10-Q for the quarter ended November 30, 1996.

(3) Incorporated by reference to the same numbered Exhibit to Registrant's Form 10-Q for the quarter ended February 28, 1997.

(4) Incorporated by reference to the same numbered Exhibit to Registrant's Form 10-Q for the quarter ended May 31, 1998.

(5) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 1998.

(6) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 1999.
(7) Incorporated by reference to the Exhibit 10.16.3 to the Registrant's Form 10-Q for the quarter ended May 31, 2000.
(8) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K dated August 23, 2000.
(9) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 2000.
(10) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended February 28, 2001.
(11) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 2001.
(14) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended November 30, 2001.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended February 28, 2002.
(16) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2002.
(17) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K dated February 4, 2002.
(18) Incorporated by reference as the same numbered exhibit to the Registrant's Form 10-Q for the quarter ended February 29, 2004.
(19) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended February 29, 2004.
(20) Incorporated by reference to Annex A of the Registrant's Schedule 14A Proxy Statement filed May 18, 2004.
(21) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 1, 2004.
(22) Incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed January 19, 2005.
(23) Incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 19, 2005.
(24) Incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed January 19, 2005.
(25) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed February 1, 2005.
(26) Incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed February 1, 2005.
(27) Incorporated by reference to Exhibit 3.1.7 to the Registrant's Form 8-K filed March 16, 2005.
(28) Incorporated by reference to Exhibit 3.1.8 to the Registrant's Form 8-K filed February 9, 2006.
(29) Incorporated by reference to Exhibit 10.45 to the Registrant's Form 10-Q for the quarter ended February 28, 2005.
(30) Incorporated by reference to Exhibit 10.39.1 to the Registrant's Form 10-Q for the quarter ended February 28, 2005.

(31) Incorporated by reference to Exhibit 4.1 to the Registrant’s Form 8-K filed August 2, 2005.
(32) Incorporated by reference to Exhibit 4.2 to the Registrant’s Form 8-K filed August 2, 2005.
(33) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-K/A for the year ended August 31, 2005.
(34) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 8-K filed December 16, 2005.
(35) Incorporated by reference to Exhibit 10.2 to the Registrant’s Form 8-K filed December 16, 2005.
(36) Incorporated by reference to Exhibit 4.1 to the Registrant’s Form 8-K filed October 25, 2006.
(37) Incorporated by reference to Exhibit 3.1.10 to the Registrant’s Form 8-K filed November 3, 2006.
(38) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-Q for the quarter ended May 31, 2006.
(39) Incorporated by reference to Exhibit 3.1.9 to the Registrant’s Form 8-K filed May 3, 2006.
(40) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 8-K filed September 18, 2006.
(41) Incorporated by reference to Exhibit 10.2 to the Registrant’s Form 8-K filed September 18, 2006.
(42) Incorporated by reference to Exhibit 10.3 to the Registrant’s Form 8-K filed September 18, 2006.
(43) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-K for the year ended August 31, 2006.
(44) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-Q for the quarter ended February 28, 2007.
(45) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-Q for the quarter ended May 31, 2007.
(46) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 8-K filed on July 23, 2007.
(47) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 8-K filed on October 9, 2007.
(48) Incorporated by reference to Exhibit 3.1.11 to the Registrant’s Form 8-K filed on January 18, 2008.
(49) Incorporated by reference to Exhibit 10.6.5 to the Registrant’s Form 10-Q for the quarter ended November 30, 2007.
(50) Incorporated by reference to Exhibit 10.6.6 to the Registrant’s Form 10-Q for the quarter ended June 30, 2008.
(51) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 8-K filed March 3, 2008.
(52) Incorporated by reference to Exhibit 4.2 to the Registrant’s Form 8-K filed March 28, 2008.
(53) Incorporated by reference to Exhibit 4.1 to the Registrant’s Form 8-K filed April 24, 2008.
(54) Incorporated by reference to Exhibit 2.1 to the Registrant’s Form 8-K/A filed September 26, 2008.

Table of Contents

SIGNATURE

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

	ENERGY TRANSFER PARTNERS, L.P.
	By: Energy Transfer Partners GP, L.P., its General Partner
	By: Energy Transfer Partners, L.L.C., its General Partner
Date: November 10, 2008	By: /s/ Martin Salinas, Jr. Martin Salinas, Jr. (Chief Financial Officer duly authorized to sign on behalf of the registrant)

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kelcy L. Warren, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize, and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 10, 2008

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Martin Salinas, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize, and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 10, 2008

/s/ Martin Salinas, Jr.
Martin Salinas, Jr.
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kelcy L. Warren, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 10, 2008

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Energy Transfer Partners, L.P.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Martin Salinas, Jr., Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 10, 2008

/s/ Martin Salinas, Jr.
Martin Salinas, Jr.
Chief Financial Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Energy Transfer Partners, L.P.