Energy Transfer Partners, L.P.
Form 10-QT
February 11, 2008
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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 ________

OR

x **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition Period from September 1, 2007 to December 31, 2007

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue

Dallas, Texas 75219

(Address of principal executive offices and zip code)

(214) 981-0700

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer ¨ Non accelerated filer ¨

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

At February 11, 2008, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	142,819,957 Common Units

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Energy Transfer Partners, L.P. and Subsidiaries

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (Energy Transfer Partners or the Partnership) in periodic press releases and some oral statements of Energy Transfer Partners officials during presentations about the Partnership, include certain forward-looking statements 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 Transition Report on Form 10-Q as well as the Partnership s Annual Report on Form 10-K for the fiscal year ended August 31, 2007 filed with the Securities and Exchange Commission 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.
Dekatherm	Million British thermal units. 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.

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	December 31, 2007	August 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 56,467	$ 68,705
Marketable securities	3,002	3,099
Accounts receivable, net of allowance for doubtful accounts	822,027	637,676
Accounts receivable from related companies	24,438	6,900
Inventories	361,954	192,276
Deposits paid to vendors	42,273	45,490
Prepaid expenses and other current assets	99,798	86,947
Total current assets	1,409,959	1,041,093
PROPERTY, PLANT AND EQUIPMENT, net	6,433,788	5,548,383
ADVANCES TO AND INVESTMENT IN AFFILIATES	86,167	56,564
GOODWILL	728,109	718,429
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	350,138	343,959
Total assets	$ 9,008,161	$ 7,708,428

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	December 31, 2007	August 31, 2007
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 672,388	$ 487,148
Accounts payable to related companies	48,483	19,471
Exchanges payable	40,382	34,252
Customer advances and deposits	75,831	81,919
Accrued and other current liabilities	331,341	254,396
Current maturities of long-term debt	47,036	47,031
Total current liabilities	1,215,461	924,217
LONG-TERM DEBT, less current maturities	4,297,264	3,626,977
DEFERRED INCOME TAXES	102,762	100,810
OTHER NON-CURRENT LIABILITIES	13,483	16,591
COMMITMENTS AND CONTINGENCIES (Note 13)		
Total liabilities	5,628,970	4,668,595
PARTNERS CAPITAL:		
General Partner	160,193	127,046
Limited Partners:		
Common Unitholders (142,069,957 and 136,981,221 units authorized, issued and outstanding at December 31, 2007 and August 31, 2007, respectively)	3,192,092	2,890,140
Class E Unitholders (8,853,832 units authorized, issued and outstanding - held by subsidiary and reported as treasury units)		
	3,352,285	3,017,186
Accumulated other comprehensive income, per accompanying statements	26,906	22,647
Total partners capital	3,379,191	3,039,833
Total liabilities and partners capital	$ 9,008,161	$ 7,708,428

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Four Months Ended December 31, 2007	2006
REVENUES:		
Natural gas operations	$ 1,832,192	$ 1,668,667
Retail propane	471,494	409,821
Other	45,824	83,978
Total revenues	2,349,510	2,162,466
COSTS AND EXPENSES:		
Cost of products sold - natural gas operations	1,343,237	1,382,473
Cost of products sold - retail propane	315,698	256,994
Cost of products sold - other	14,719	50,376
Operating expenses	221,757	173,365
Depreciation and amortization	71,333	48,767
Selling, general and administrative	59,132	40,603
Total costs and expenses	2,025,876	1,952,578
OPERATING INCOME	323,634	209,888
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(66,298)	(54,946)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Other income, net	1,061	2,158
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	272,613	164,055
Income tax expense	10,789	3,120
INCOME BEFORE MINORITY INTERESTS	261,824	160,935
Minority interests		(490)
NET INCOME	261,824	160,445
GENERAL PARTNER S INTEREST IN NET INCOME	91,011	73,204
LIMITED PARTNERS INTEREST IN NET INCOME	$ 170,813	$ 87,241
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.22	$ 0.70
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	137,624,934	123,931,608
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.21	$ 0.70

DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	138,013,366	124,229,968

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	2006
Net income	$ 261,824	$ 160,445
Other comprehensive income (loss), net of tax:		
Reclassification adjustment for gains and losses on derivative instruments accounted for as cash flow hedges included in net income	(17,269)	(23,698)
Change in value of derivative instruments accounted for as cash flow hedges	21,626	152,653
Change in value of available-for-sale securities	(98)	(401)
Comprehensive income	$ 266,083	$ 288,999
Reconciliation of Accumulated Other Comprehensive Income (Loss), net of tax		
Balance, beginning of period	$ 22,647	$ 7,067
Current period reclassification to earnings	(17,269)	(23,698)
Current period change in value	21,528	152,252
Balance, end of period	$ 26,906	$ 135,621
Components of Accumulated Other Comprehensive Income (Loss), net of tax		
Commodity related hedges	$ 25,497	$ 134,649
Interest rate hedges	926	1,073
Available-for-sale securities	483	(101)
Balance, end of period	$ 26,906	$ 135,621

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE FOUR MONTHS ENDED DECEMBER 31, 2007

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders
Balance, August 31, 2007	$ 127,046	$ 2,890,140
Distributions to partners	(62,897)	(113,080)
Issuance of units in acquisitions		1,400
Issuance of units in public offering		234,887
General Partner capital contribution	5,009	
Tax effect of remedial income allocation from tax amortization of goodwill		(1,161)
Units returned by employees for tax withholdings		(164)
Non-cash executive compensation	24	1,143
Unit-based compensation expense		8,114
Net income	91,011	170,813
Balance, December 31, 2007	$ 160,193	$ 3,192,092

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 245,702	$ 420,910
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(337,092)	(67,089)
Capital expenditures	(647,735)	(331,489)
Advances to and investment in affiliates	(32,594)	(953,247)
Proceeds from the sale of assets	21,478	7,644
Net cash used in investing activities	(995,943)	(1,344,181)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	1,741,547	1,667,810
Principal payments on debt	(1,062,272)	(1,737,788)
Net proceeds from issuance of Limited Partner Units	234,887	1,200,000
Capital contribution from General Partner	29	24,489
Distributions to partners	(175,977)	(125,774)
Debt issuance costs	(211)	(9,451)
Net cash provided by financing activities	738,003	1,019,286
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(12,238)	96,015
CASH AND CASH EQUIVALENTS, beginning of period	68,705	26,041
CASH AND CASH EQUIVALENTS, end of period	$ 56,467	$ 122,056

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in thousands, except per unit data)

(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of August 31, 2007, which has been derived from audited financial statements, and the unaudited transition period financial statements and notes thereto of Energy Transfer Partners, L.P., and subsidiaries (collectively, we or the Partnership) as of December 31, 2007 and for the four-month periods ended December 31, 2007 and 2006, 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 Securities and Exchange Commission (SEC). Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership s operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners, L.P. and subsidiaries as of December 31, 2007, and the Partnership s results of operations and cash flows for the four-month periods ended December 31, 2007 and 2006, respectively. The unaudited interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership s Annual Report on Form 10-K for the fiscal year ended August 31, 2007, as filed with the Securities and Exchange Commission on October 30, 2007.

On November 9, 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 next full fiscal year will begin on January 1, 2008. These financial statements are being filed as part of a transition report on Form 10-Q covering the transition period that began September 1, 2007 and ended December 31, 2007. Pursuant to Form 8-K.I. Item 5.03, *Amendment to Articles of Incorporation or Bylaws; Change in Fiscal Year*, the Partnership has also presented the data for the four-month period ended December 31, 2006 for comparison purposes.

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 consist of four reportable segments, which are conducted through four subsidiary operating partnerships (collectively the Operating Partnerships).

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, LLC (ETC MEP), both Delaware limited liability companies 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, LP (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.

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Our interstate transportation operations principally focus on natural gas transportation of Transwestern.

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

2. SIGNIFICANT ACQUISITIONS:

Four-Month Transition Period Ended December 31, 2007

On October 5, 2007, we acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the Canyon acquisition) for $305,152 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 1,800 miles of 2-inch to 16-inch pipe with a projected capacity of over 300,000 MMBtu/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 cash paid for this acquisition was financed with borrowings under a new $310,000 term loan facility, as discussed further in Note 11.

The Canyon acquisition was accounted for under the purchase method of accounting in accordance with SFAS 141, and the purchase price was preliminarily allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition, as follows:

Accounts receivable	$ 4,303
Inventory	183
Prepaid and other current assets	1,612
Property, plant, and equipment	284,910
Contract rights and customer lists (6 to 15 year life)	6,351
Goodwill	10,959
Total assets acquired	308,318
Accounts payable	(2,299)
Customer advances and deposits	(867)
Total liabilities assumed	(3,166)
Net assets acquired	$ 305,152

We expect to finalize the purchase price allocation in the third calendar quarter of 2008.

Four-Month Period Ended December 31, 2006

On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services (GE) and Southern Union Company (Southern Union), we acquired the member interests in CCE Holdings, LLC (CCEH) from GE and certain other investors for $1,000,000. We financed a portion of the CCEH purchase price with the proceeds from our issuance of 26,086,957 Class G Units to Energy Transfer Equity, L.P. simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP s 50% ownership interest in CCEH in exchange for 100% ownership of Transwestern which owns the Transwestern pipeline. Following the final step, Transwestern became a new operating subsidiary and separate segment of ETP.

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The total acquisition cost for Transwestern, net of cash acquired, was as follows:

Basis of investment in CCEH at November 30, 2006	$ 956,348
Distributions received on December 1, 2006	(6,217)
Fair value of short-term debt assumed	13,000
Fair value of long-term debt assumed	519,377
Other assumed long-term indebtedness	10,096
Current liabilities assumed	35,781
Cash acquired	(3,386)
Acquisition costs incurred	11,696
Total	$ 1,536,695

The Transwestern acquisition was accounted for under the purchase method of accounting in accordance with SFAS 141 and the purchase price was allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. The acquisition of the 50% member interest in CCEH was accounted for under the equity method of accounting in accordance with APB Opinion No. 18, through November 30, 2006. Pro forma effects of the Transwestern acquisition are discussed below.

Pro Forma Results of Operations (Unaudited)

The following unaudited pro forma consolidated results of operations for the four-month period ended December 31, 2006 are presented as if the Transwestern acquisition had been made on September 1, 2006. The operations of Transwestern have been included in our statements of operations since acquisition.

	Four Months Ended December 31, 2006
Revenues	$ 2,221,358
Net income	$ 177,278
Limited Partners interest in net income	$ 103,737
Basic earnings per Limited Partner Unit	$ 0.76
Diluted earnings per Limited Partner Unit	$ 0.76

The pro forma consolidated results of operations include adjustments to give effect to depreciation on the step-up of property, plant and equipment, amortization of customer lists, interest expense on acquisition debt, and certain other adjustments. The pro forma information is not necessarily indicative of the results of operations that would have occurred had the Transwestern acquisition been made at the beginning of the period presented or the future results of the combined operations.

3. ESTIMATES 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 four months ended December 31, 2007 and 2006 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.

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New Accounting Standards

FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109*, (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS 109. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We adopted FIN 48 on September 1, 2007, which adoption did not have a significant impact on our consolidated financial statements.

FASB Statement No. 157, *Fair Value Measurement*, (SFAS 157). This standard provides guidance for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently evaluating the impact of our adoption of this statement effective January 1, 2008 on our consolidated financial statements.

FASB Statement No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of SFAS Statements No. 87, 88, 106 and 132(R)*, (SFAS 158). Issued in September 2006, this statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multi-employer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. We adopted the recognition and disclosure provisions of SFAS 158 on December 1, 2006 in connection with our acquisition of Transwestern, the effect of which was not material. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. The adoption of the measurement provisions of this statement on January 1, 2008 did not have a material impact on our consolidated financial statements.

FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*, (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective;

however, the amendment applies to all entities with available-for-sale and trading securities. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes the choice in the first 120 days of that fiscal year and also elects to apply the provisions of SFAS 157 (discussed above). We are currently evaluating the impact of our adoption of this statement effective January 1, 2008 on our consolidated financial statements.

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 be generally 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;

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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, with the change in our year end (see Note 1), we are required to record and disclose business combinations following existing GAAP until January 1, 2009.

FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No, 51* (SFAS 160). On December 4, 2007, the FASB issued SFAS 160. SFAS 160 establishes new accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, SFAS 160 requires the recognition of a non-controlling interest (minority interest) as equity in the consolidated financial statements and separate from the parent s equity. The amount of net income attributable to the non-controlling interest will be included in consolidated net income on the face of the income statement. SFAS 160 clarifies that changes in a parent s ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, SFAS 160 requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss will be measured using the fair value of the non-controlling equity investment on the deconsolidation date. SFAS 160 also includes expanded disclosure requirements regarding the interests of the parent and its non-controlling interest. SFAS 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. We are currently evaluating the impact of SFAS 160 on our consolidated financial statements.

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

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

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, such balances may be in excess of the Federal Deposit Insurance Corporation (FDIC) insurance limit.

Net cash flows provided by operating activities is comprised as follows:

	Four Months Ended December 31,	
	2007	**2006**
Net income	$ 261,824	$ 160,445
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	71,333	48,767
Amortization of finance costs charged to interest	1,435	1,068
Provision for loss on accounts receivable	544	563
Non-cash compensation on unit grants	8,114	4,385
Non-cash executive compensation	442	
Deferred income taxes	1,003	(2,234)
Gain on disposal of assets	(14,310)	(2,212)
Undistributed earnings of affiliates, net	4,448	(4,743)
Minority Interests and other	(2,069)	414
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	(169,263)	(32,895)
Accounts receivable from related companies	(12,557)	(550)
Inventories	(168,430)	9,899
Deposits paid to vendors	3,243	26,548

Exchanges receivable	(4,216)	6,684
Prepaid expenses and other	(7,944)	(15,422)
Intangibles and other long-term assets	2,523	(1,000)
Regulatory assets	(1,918)	1,006
Accounts payable	195,644	(555)
Accounts payable to related companies	29,012	3,505
Customer advances and deposits	(6,775)	(22,695)
Exchanges payable	6,117	(1,842)
Accrued and other current liabilities	40,383	79,716
Other long-term liabilities	(680)	2,427
Income taxes payable	777	890
Price risk management liabilities, net	7,022	158,741
Net cash provided by operating activities	$ 245,702	$ 420,910

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Non-cash financing and supplemental cash flow information is as follows:

	Four Months Ended December 31, 2007	2006
NON-CASH FINANCING ACTIVITIES:		
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 3,896	$ 532,631
Issuance of common units in connection with certain acquisitions	$ 1,400	$
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the period for interest, net of $12,657 and $4,802 capitalized for December 31, 2007 and 2006, respectively	$ 51,465	$ 27,496
Cash paid during the period for income taxes	$ 9,009	$ 6,196

5. ACCOUNTS RECEIVABLE:

Accounts receivable consisted of the following:

	December 31, 2007	August 31, 2007
Accounts receivable - midstream and intrastate transportation and storage	$ 612,533	$ 529,655
Accounts receivable - interstate transportation	31,676	20,193
Accounts receivable - propane	183,516	93,429
Less - allowance for doubtful accounts	(5,698)	(5,601)
Total, net	$ 822,027	$ 637,676

The activity in the allowance for doubtful accounts for the propane operations for the four months ended December 31, 2007 consisted of the following:

Balance, beginning of period	$ 5,601
Provision for loss on accounts receivable	544
Accounts receivable written off, net of recoveries	(447)
Balance, end of period	$ 5,698

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6. INVENTORIES:

Inventories consist principally of natural gas held in storage valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are also valued at the lower of cost or market utilizing the weighted-average cost of propane delivered to the customer service locations, including storage fees and inbound freight costs. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31, 2007	August 31, 2007
Natural gas, propane and other NGLs	$ 342,457	$ 174,164
Appliances, parts and fittings and other	19,497	18,112
Total inventories	$ 361,954	$ 192,276

7. GOODWILL:

Goodwill is associated with acquisitions made for our midstream, intrastate transportation and storage, interstate transportation and retail propane segments. In accordance with Statement of Accounting Standards No. 142, *Goodwill and Other Intangible Assets,* (SFAS 142), goodwill is tested for impairment annually at our fiscal year end. With the change in our year to a calendar year, as discussed in Note 1, the next assessment period for which we will be required to test goodwill will be as of December 31, 2008. The changes in the carrying amount of goodwill during the four-month period ended December 31, 2007 were as follows:

	Midstream	Intrastate Transportation and Storage	Interstate Transportation	Retail Propane	Total
Balance, August 31, 2007	$ 13,409	$ 10,327	$ 107,550	$ 587,143	$ 718,429
Purchase accounting adjustments			(8,937)	190	(8,747)
Goodwill acquired	10,959			7,742	18,701
Sale of operations				(274)	(274)
Balance, December 31, 2007	$ 24,368	$ 10,327	$ 98,613	$ 594,801	$ 728,109

The purchase price allocations for the Canyon and other fiscal 2008 acquisitions (see Note 2) are preliminary based on estimated fair values. There is no guarantee that the preliminary allocations will not change.

8. ACCRUED AND OTHER CURRENT LIABILITIES:

Accrued and other current liabilities consist of the following:

	December 31, 2007	August 31, 2007
Accrued wages and benefits	$ 35,408	$ 53,109
Capital expenditures	87,622	43,498
Operating expenses	19,773	12,439
Litigation, environmental and other contingencies	35,707	35,707
Interest	63,254	29,828

Income taxes payable	7,012	6,234
Taxes other than income taxes	48,437	42,957
Other	34,128	30,624
Total accrued and other current liabilities	$ 331,341	$ 254,396

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9. INCOME TAXES:

Energy Transfer Partners, L.P. is a limited partnership. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under the Partnership Agreement.

As a limited partnership, we are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the four-month periods ended December 31, 2007 and 2006, our non-qualifying income did not, or was not expected to, exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109). Under SFAS 109, deferred income taxes are recorded based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law s effective date of January 1, 2007. For the four months ended December 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $3,905. There was no comparable state tax expense for the four months ended December 31, 2006.

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

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
Current provision:		
Federal	$ 2,990	$ 4,797
State	5,705	557
Total	8,695	5,354
Deferred provision (benefit):		
Federal	1,482	(1,972)
State	612	(262)
Total	2,094	(2,234)
Total tax provision	$ 10,789	$ 3,120
Effective tax rate	3.96%	1.91%

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. The difference between the statutory rate and the effective rate is summarized as follows:

Four Months Ended December 31,

	2007	2006
Federal statutory tax rate	35.00%	35.00%
State income tax rate net of federal benefit	1.82%	3.48%
Earnings not subject to tax at the Partnership level	(32.86)%	(36.57)%
Effective tax rate	3.96%	1.91%

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10. INCOME PER LIMITED PARTNER UNIT:

Our net income for partners capital and income statement presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the Incentive Distribution Rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. Basic net income per limited partner unit, however, is computed in accordance with EITF Issue No. 03-6, *Participating Securities and the Two-Class Method Under FASB Statement No. 128* (EITF 03-6), by dividing limited partners interest in net income by the weighted average number of limited partner units outstanding (excluding treasury units). In periods when our aggregate net income exceeds the aggregate distributions, EITF 03-6 requires us to present earnings per unit as if all of the earnings for the period were distributed (see table below) and requires a separate computation for each quarter and year-to-date. For such periods, an increased amount of net income is allocated to the General Partner for the additional pro forma priority income attributable to the application of EITF 03-6. The General Partner is entitled to receive incentive distributions if the amount we distribute to our limited partners with respect to any quarter exceeds levels specified in the Partnership Agreement. Diluted net income per limited partner unit is computed by dividing net income available to limited partners, after considering the General Partner s interest, by the weighted average number of limited partner units outstanding and of the effect (if dilutive) of non-vested restricted units (Unit Grants) granted under the Amended and Restated 2004 Unit Plan and predecessor plan computed using the treasury stock method.

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

	Four Months Ended December 31, 2007	2006
Net income	$ 261,824	$ 160,445
Adjustments:		
General Partner s equity ownership	(5,236)	(3,209)
General Partner s incentive distributions	(85,775)	(69,995)
Limited Partners interest in net income	170,813	87,241
Additional earnings allocation to General Partner	(3,430)	
Net income available to limited partners	$ 167,383	$ 87,241
Weighted average limited partner units basic	137,624,934	123,931,608
Basic net income per limited partner unit	$ 1.22	$ 0.70
Weighted average limited partner units	137,624,934	123,931,608
Dilutive effect of Unit Grants	388,432	298,360
Weighted average limited partner units, assuming dilutive effect of Unit Grants	138,013,366	124,229,968
Diluted net income per limited partner unit	$ 1.21	$ 0.70

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11. DEBT OBLIGATIONS:

ETP Term Loan Facility

On December 18, 2007, we used proceeds received from an equity offering (see Note 12) and funds from the ETP Credit Facility to fully repay the ETP Term Loan Facility, a $310,000, 364-day term loan credit facility we executed on October 5, 2007 primarily to finance the Canyon acquisition. The ETP Term Loan Facility was a single draw term loan with an applicable Eurodollar rate plus 0.600% per annum based on our current rating by the rating agencies or at Base Rate for designated period.

ETP Credit Facility

We have available a $2,000,000 revolving credit facility (the ETP Credit Facility) that is expandable to $3,000,000 at our option (subject to the approval of the administrative agent under the Amended and Restated Credit Agreement, which approval is not to be unreasonably withheld) 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 under the ETP Credit Facility). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The ETP Credit Facility has a swingline loan option of which borrowings and aggregate principal amounts shall not exceed the lesser of (i) the aggregate commitments ($2,000,000 unless expanded to $3,000,000) less the sum of all outstanding revolving credit loans and the letter of credit obligation and (ii) the swingline commitment. The aggregate amount of swingline loans in any borrowing shall not be subject to a minimum amount or increment. The indebtedness under the ETP Credit Facility is prepayable at any time at the Partnership s option without penalty. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating (0.11% based on our current rating) with a maximum fee of 0.125%.

As of December 31, 2007, there was a balance of $1,626,948 in revolving credit loans (including $273,948 in swingline loans) and $61,336 in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2007, was 5.746%. The total amount available under the ETP Credit Facility, as of December 31, 2007, which is reduced by any amounts outstanding under the swingline loan and letters of credit, was $311,716. 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 $75,000 Senior Revolving Facility (the HOLP Facility) is available to HOLP through June 30, 2011 which may be expanded to $150,000. The HOLP Facility has a swingline loan option with a maximum borrowing of $10,000 at a prime rate. Amounts borrowed under the HOLP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the HOLP Facility credit agreement, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Facility. As of December 31, 2007, there was $15,000 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 Facility. There were outstanding letters of credit of $1,002 at December 31, 2007. The weighted average interest rate on the total amount outstanding at December 31, 2007, was 5.97%. The sum of the loans made under the HOLP Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the $75,000 maximum amount of the HOLP Facility. The amount available at December 31, 2007 was $58,998.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes (collectively, the HOLP Notes). In addition to the stated interest rate for the HOLP Notes, we are required to pay an additional 1% per annum on the outstanding balance of the HOLP Notes at such time as the HOLP Notes are not rated investment grade status or higher. As of December 31, 2007 the HOLP Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

12. PARTNERS CAPITAL AND UNIT-BASED COMPENSATION PLANS:

On November 7, 2007, the Board of Directors of our General Partner approved an amendment to the Amended and Restated Agreement of Limited Partnership of ETP, and this amendment became effective on November 9,

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2007. This amendment changes the fiscal year of ETP from a year ending on August 31 to a year ending on December 31. In order to transition to the new fiscal year, the amendment also provides that, in lieu of making a cash distribution to ETP s unitholders, general partner and holder of the incentive distribution rights with respect to the three-month period ended November 30, 2007, ETP will make a cash distribution for the four-month period ending December 31, 2007, which distribution will be made within 45 days following the end of such four-month period. The amendment also specifies proportional adjustments to the cash distribution target levels relating to the incentive distribution rights for this four-month period in order to reflect the longer period upon which the distribution will be made (essentially multiplying each cash distribution target level by 4/3). Finally, the amendment provides that, following this one-time four-month distribution period, ETP will make cash distributions with respect to each calendar quarter within 45 days following the end of each calendar quarter.

Limited Partner Units

Limited Partner interests are represented by Common and Class E Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. As of December 31, 2007, we had 142,069,957 Common Units issued and outstanding representing an aggregate 98% Limited Partner interest in us. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.

No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that the General Partner, Energy Transfer Partners GP, L.P. (ETP GP) has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance. In addition to this right, ETP GP, as our General Partner, has an obligation to contribute additional capital in connection with any such issuance of equity securities by us in order to maintain its 2% general partner interest as discussed below.

Incentive Distribution Rights represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. ETP GP owns all of the Incentive Distribution Rights.

Common Units

Our Common Units are registered under the Securities Act of 1934 and are listed for trading on the New York Stock Exchange. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement.

The change in Common Units during the four-month period ended December 31, 2007 is as follows:

	Number of Units
Balance, beginning of period	136,981,221
Issuance of Common Units in connection with certain acquisitions	27,348
Common Units issued in connection with the S-3 offering	5,000,000
Issuance of Common Units under the 2004 Unit Plan	64,600
Units returned by employees for tax withholdings	(3,212)
Balance, end of period	142,069,957

Of the total Common Units issued during the period, 56,482 were employee awards under our 2004 Unit Plan (discussed below), 8,118 were Director Awards under our 2004 Unit Plan which vested on September 1, 2007.

The 2004 Unit Plan provides that recipients may elect to relinquish their right to a portion of the vesting units as payment for the income tax obligations arising as a result of the unit vesting, based on the Compensation

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Committee s determination of the fair market value of the units. For the four-month period ended December 31, 2007, participants entitled to unit vesting elected to relinquish a total of 3,212 units under such provision. The fair market value of the units was determined by the Compensation Committee as $51.15 per unit, determined as the arithmetic average of the closing price for the 10 trading days prior to October 2, 2007, the date the employees were first notified of the ability to relinquish the units for such tax payment.

On December 18, 2007, the Partnership sold in a public offering 5,000,000 common units representing limited partner interests at $48.81 per common unit. ETP used the offering proceeds of $234,887, net of issuance costs, to repay a portion of the outstanding debt under the ETP Term Loan Facility. The remaining balance on the ETP Term Loan Facility was repaid with funds from the ETP Credit Facility. ETP also granted the underwriters a 30-day option to purchase up to an aggregate of 750,000 additional common units to cover over-allotments, if any. The underwriters exercised their option in full and we issued 750,000 additional common units at $48.81 per common unit on January 8, 2008. The proceeds of $35,235, net of offerings costs, were used to repay borrowings from the ETP Credit Facility.

ETP GP is required to make contributions to ETP each time ETP issues limited partner interests for cash or in connection with acquisitions in order to maintain its 2% general partner interest in ETP. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP. ETP GP was required to contribute $5,009 for the four months ended December 31, 2007.

Quarterly Distributions of Available Cash

On October 15, 2007, we paid a quarterly distribution related to the fourth quarter of our fiscal year 2007 of $0.825 per Common Unit, or $3.30 per unit on an annualized basis, to Unitholders of record at the close of business on October 5, 2007. ETP GP also received distributions for its general partner interest in the Partnership and incentive distributions to the extent the quarterly distribution exceeded $0.275 per unit.

On January 18, 2008 our Board of Directors approved the previously announced management recommendation for a one-time four-month distribution for ETP Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETP s distribution amount related to the four months ended December 31, 2007 will be $1.125 per unit, ($3.375 per unit annualized), representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This represents an increase of $0.075 per unit on an annualized basis. The distribution will be paid on February 14, 2008 to Unitholders of record as of the close of business on February 1, 2008.

After this distribution payment, the Partnership will continue to make quarterly distributions on a three-month basis as we have done in the past. Going forward, the new quarterly distribution payment schedule will be mid February, mid May, mid August, and mid November.

Unit-Based Compensation Plans

We follow the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004) *Accounting for Stock-based Compensation* (SFAS 123R) for our unit-based compensation plans. Generally, the recipients of the stock grants are not entitled to receive any unit distributions during the required service period for vesting. Accordingly, as provided in SFAS 123R, the Partnership values the unit awards based on the per unit grant-date market value reduced by the present value of the distributions expected to be paid on the units during the requisite service period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the expected unit distributions.

We recognized compensation expense related to unit-based compensation plans of $8,114 and $4,385 for the four months ended December 31, 2007 and 2006, respectively.

2004 Unit Plan

Our Amended and Restated 2004 Unit Award Plan (the 2004 Unit Plan) provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers, and directors. Any awards that are forfeited or which expire for any reason or any units which are not used in the settlement of an award will be available for grant under the 2004 Unit Plan. Units to be delivered upon the vesting of awards granted under the 2004 Unit

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Plan may be (i) units acquired by us in the open market, (ii) units already owned by us or our General Partner, or (iii) units acquired by us or our General Partner directly from us, or any other person. We may issue units under the 2004 Unit Plan without registration under the federal securities law, in which case holders of these units would be subject to restrictions on their ability to sell these units, or we may issue units pursuant to an S-8 registration statement filed in September 2007, in which case the holders of these units would not be subject to these restrictions. As of December 31, 2007, 433,751 ETP Common Units were available for future grants under the 2004 Unit Plan.

The 2004 Unit Plan is administered by the Compensation Committee of the Board of Directors of our General Partner (the Compensation Committee) and may be amended from time to time by the Board; provided however, that no amendment will be made without the approval of a majority of the Unitholders (i) if so required under the rules and regulations of the New York Stock Exchange or the Securities and Exchange Commission; (ii) that would extend the maximum period during which an award may be granted under the Plan; (iii) materially increase the cost of the Plan to the Partnership; or (iv) result in this Plan no longer satisfying the requirements of Rule 16b-3 of Section 16 of the Securities and Exchange Act of 1934. This Plan shall terminate no later than the 10th anniversary of its original effective date (June 23, 2014).

Employee Grants

The Compensation Committee, in its discretion, may from time to time grant awards to any employee, upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by the 2004 Unit Plan. All outstanding awards shall fully vest into units upon any Change in Control as defined by the 2004 Unit Plan, or upon such terms as the Compensation Committee may require at the time the award is granted. The issuance of Common Units pursuant to the 2004 Unit Plan is intended to serve as a means of incentive compensation, therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

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 has been 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 are 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. 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.

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, including the grant on December 5, 2007 of unit awards to employees relating to an aggregate of 558,750 common units.

On October 2, 2007 the Compensation Committee of our General Partner determined that based on our performance for the year ended August 31, 2007, of the 225,887 employee awards scheduled to vest on September 1, 2007, 25%, or 56,482 employee awards vested and 75%, or 169,405 awards were forfeited. The Compensation Committee of our General Partner also approved a special one-time grant of 158,080 employee awards to vest on October 2, 2008, which are not subject to performance objectives but are subject only to continued employment with us through the first anniversary of the grant date of October 2, 2007.

We assumed a weighted average risk-free interest rate of 3.70% for the four months ended December 31, 2007 in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each employee grant. For the employee awards outstanding as of the period ended December 31, 2007, the grant-date average per unit cash distributions were estimated to be $7.56. Upon vesting, ETP Common Units are issued.

The following table shows the activity of the employee grants during the four months ended December 31, 2007:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of August 31, 2007	557,437	$ 39.08
Awards granted	716,830	42.45
Awards vested	(56,482)	35.14

Awards forfeited	(178,256)		35.31
Unvested awards as of December 31, 2007	1,039,529	$	42.27

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The total expected compensation expense to be recognized related to the unvested employee awards as of December 31, 2007 is $20,547 for the year ending December 31, 2008, $7,228 for the year ending December 31, 2009, $3,580 for the year ending December 31, 2010, $1,936 for the year ending December 31, 2011, and $782 for the year ending December 31, 2012.

Director Grants

Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, the Partnership, or a subsidiary (Director Participant), who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of up to 2,000 ETP Common Units (the Initial Director s Grant). Commencing on September 1, 2004 and each September 1 thereafter that this Plan is in effect, each Director Participant who is in office on such September 1, shall automatically receive an award of Units equal to $25 divided by the fair market value of a Common Unit on such date rounded to the nearest increment of ten Units (Annual Director s Grant). Each grant of an award to a Director Participant will vest at the rate of one third per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, (i) all awards to a Director Participant shall become fully vested upon a change in control, as defined by the 2004 Unit Plan, unless voluntarily waived by such Director Participant, and (ii) all awards which have not yet vested on the date a Director Participant ceases to be a director shall vest on such terms as may be determined by the Compensation Committee.

We assumed a weighted average risk-free interest rate of 4.48% for the four months ended December 31, 2007 in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each Director Grant. For the unvested Director Awards as of December 31, 2007, the grant-date average per unit cash distributions were estimated to be $6.15.

The following table shows the activity of the Director Grants during the four months ended December 31, 2007:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of August 31, 2007	12,166	$ 27.63
Annual Director Grants	2,880	45.87
Awards vested	(8,118)	23.14
Unvested awards as of December 31, 2007	6,928	$ 40.47

The total expected compensation expense to be recognized related to the unvested Director Awards as of December 31, 2007 is $110 for the year ending December 31, 2008, $38 for the year ending December 31, 2009, and $9 for the year ending December 31, 2010.

Long-Term Incentive Grants

The Compensation Committee may, from time to time, grant awards under the Plan to any executive officer or any employee it designates as a participant in accordance with general guidelines under the Plan. These guidelines include (i) options to purchase a specified number of units at a specified exercise price, which are clearly designated in the award as either an incentive stock option within the meaning of Section 422 of the Internal Revenue Code, or a non-qualifying stock option that is not intended to qualify as an incentive stock option under Section 422; (ii) Unit Appreciation Rights that specify the terms of the fair market value of the award on the date the unit appreciation right is exercised and the strike price; (iii) units; or (iv) any combination hereof. As of December 31, 2007, there have been no Long-Term Incentive Grants made under the Plan.

Related Party Awards

Through December 31, 2007, a partnership, 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 ETE previously issued by ETE to such officer. These rights include the economic benefits of ownership of these units based on a 5-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 market value of the ETE units awarded the ETP employees assuming no forfeitures. Rights related to 55,000 of the ETE units vested in December 2007. Awards granted through December 31, 2007 result in a total non-cash compensation expense of approximately $23,523 to be recognized over the related vesting period. For the four-month period ended December 31, 2007, we recognized non-cash compensation expense of $3,551 as a result of these awards. As these units were outstanding prior to these awards, the 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. We expect to recognize non-cash compensation expense as follows in future periods related to these awards:

Years Ending:	
December 31, 2008	$ 6,939
December 31, 2009	4,122
December 31, 2010	2,399
December 31, 2011	1,146
December 31, 2012	175

13. 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. On March 9, 2007, Transwestern filed with the Federal Energy Regulatory Commission (the FERC) its Stipulation and Agreement of Settlement (Stipulation and Agreement) which provides for (i) revised base tariff rates, (ii) the amortization of certain costs, including the Enron Cash Balance Plan, regulatory commission expense, post retirement benefits, the accumulated reserve adjustment regulatory asset, deferred income taxes, and certain non-PCB environmental costs, and (iii) a depreciation rate of 1.20 percent for all transmission plant facilities. On April 27, 2007, the FERC approved the Stipulation and Agreement with an effective date of April 1, 2007. 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. Total project costs are estimated to be approximately $710,000 including AFUDC with projected phased-in service dates in the third and fourth calendar quarter of 2008. On September 21, 2007, the FERC issued the final Environmental Impact Statement to Transwestern and 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 January 16, 2008, the FERC issued an order granting rehearing for the limited purpose of further consideration of the matters raised or to be raised. The FERC certificate issued on November 15, 2007 remains effective and binding. Transwestern has filed motions opposing both the stay and request for rehearing. Transwestern has incurred expenditures of $260,489 through December 31, 2007 for the Phoenix project.

On December 13, 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. for a 50/50 joint development of Midcontinent Express Pipeline (MEP). MEP, 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, is currently pending necessary regulatory approvals. On February 14, 2007, MEP initiated public review of the project pursuant to the FERC s NEPA pre-filing review process. MEP filed its application with the FERC for a Natural Gas Act Section 7 Certificate of Public Convenience and Necessity in October, 2007. The Section 7 Certificate must be granted before construction may commence. The approximately $1,322,000 pipeline project is expected to be in service by the first calendar quarter of 2009.

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 $9,424 and $8,933 for the four-month periods ended December 31, 2007 and 2006, respectively, and has been included in operating expenses in the accompanying statements of operations.

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 dates 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 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 Hub and the Katy Hub near Houston, Texas. 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 negotiated rates, 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 rates would be limited to sales of natural gas to retail customers (such as utilities and other end users) and sales from our own production, and any other sales of natural gas by us would be required to be made at prices that would be subject to FERC approval. Also 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 by attempting to manipulate natural gas prices in the Houston Ship Channel. It is alleged that such manipulation was attempted during the period from late September through early December 2005 to allow us to benefit financially from our commodities derivatives positions.

In its Order and Notice, the FERC is seeking $70,134 in disgorgement of profits, plus interest, and $97,500 in civil penalties relating to these matters. 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. 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. In its lawsuit, the CFTC is seeking civil penalties of $130 per violation, or three times the profit gained from each violation, and other ancillary relief. The CFTC has not specified the number of alleged violations or the amount of alleged profit related to the matters specified in its complaint. On October 15, 2007, ETP filed a motion to dismiss in the United State District Court for the Northern District of Texas on the basis that the CFTC has not stated a valid cause of action under the Commodity Exchange Act.

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 and CFTC hold substantial enforcement authority. At this time, we are unable to predict the final outcome of these matters.

In addition to the FERC and CFTC legal actions, 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 and CFTC 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, and seek unspecified direct, indirect, consequential and exemplary damages. 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. One of the producers also seeks to intervene in the FERC proceeding, alleging that it is entitled to a FERC-ordered refund of $5,900, plus interest and costs. This producer has also filed a complaint at FERC against us and ETE requesting an agency hearing and claiming that we and ETE violated the NGA by failing to make sales for resale at negotiated rates; intentionally engaged in market manipulation; knowingly submitted misleading information to Platts; and caused damages to the producer group in the amount of $5,900. This producer has requested refunds and other remedies. On December 20, 2007, the FERC denied this producer s request to intervene in the FERC proceeding and on February 6, 2008 the FERC dismissed this producer s complaint.

In addition, 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 Commodity Exchange Act (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 also violated the CEA because we knowingly aided and abetted violations of the CEA. This action alleges that this 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 plaintiff and all other members of the putative class who purchased and/or sold natural gas futures and options contracts on NYMEX during the class period. The class action complaint consolidated two class actions which were pending against us. Following the consolidation order, the plaintiffs who had filed these two earlier class actions filed the consolidated complaint. They have requested certification of their suit as a class action, 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.

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We are expensing the legal fees, consultants fees and related 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 existing 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 Tariffs, 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. 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. 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.

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 $1,000,000 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 $347,300 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 December 31, 2007 and August 31, 2007, an accrual of $30,504 and $30,275, respectively, was recorded as accrued and other current liabilities and other non-current liabilities on our 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 remediation of 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 $11,687. 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.

We also assumed certain environmental remediation matters related to eleven sites in connection with our acquisition of the HPL System.

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Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our December 31, 2007 or our August 31, 2007 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 December 31, 2007 and August 31, 2007, an accrual on an undiscounted basis of $15,732 and $16,455, respectively, was recorded in our 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 December 31, 2007, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2010. Through December 31, 2007, a total of $4,996 of capital costs and $4,495 of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. Through December 31, 2007, a total of $4,211 of capital costs and $551 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.

14. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Accounting for Derivative Instruments and Hedging Activities

We have established a formal risk management policy in which derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction. We apply Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), as amended, to account for our derivative financial instruments. This statement requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at fair value. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

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 for the four months ended December 31, 2007. For the four months ended December 31, 2006, such gains or losses were reported in interest expense.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To reduce the impact of this price volatility, we primarily utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and propane prices. These contracts consist primarily of futures and swaps and are recorded at fair value on the condensed consolidated balance sheets. We have established a formal risk management policy in which derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction. Furthermore, management reviews the creditworthiness of the derivative counterparties to manage against the risk of default on a weekly basis.

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis swaps to manage our exposure to market fluctuations in the prices of natural gas and NGLs. We enter into these financial instruments with brokers who are clearing members with NYMEX and directly with counterparties in the over-the-counter (OTC) market. We are subject to margin deposit requirements under the OTC agreements and NYMEX positions. NYMEX requires brokers to obtain an initial margin deposit based on an expected volume of the trade when the financial instrument is initiated. This amount is paid to the broker by both counterparties of the financial instrument to protect the broker from default by one of the counterparties when the financial instrument settles. We also have maintenance margin deposits with certain counterparties in the OTC market. 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 $42,248 and $45,490 as of December 31, 2007 and August 31, 2007, respectively, reflected as deposits paid to vendors on our condensed consolidated balance sheets.

The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

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 Accumulated Other Comprehensive Income (OCI) 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. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges are included in cost of products sold in the period the hedged transactions occur. Gains and losses deferred in OCI related to cash flow hedges remain in OCI 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 those financial derivative instruments that do not qualify for hedge accounting, the change in market value is recorded in cost of products sold in the condensed consolidated statements of operations. We reclassified into earnings gains of $17,145 and $23,716 for the four months ended December 31, 2007 and 2006, respectively, related to commodity financial instruments that were previously reported in OCI.

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We expect gains of $25,113 to be reclassified into earnings over the next twelve months related to income currently reported in OCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs. The majority of our commodity-related derivatives are expected to settle within the next year.

In the course of normal operations, we routinely enter into contracts such as forward physical contracts for the purchase and sale of natural gas, propane, and other NGLs, that under SFAS 133, qualify for and are designated as a normal purchase and sales contracts. Such contracts are exempted from the fair value accounting requirements of SFAS 133 and are accounted for using accrual accounting.

Trading Activities

Trading activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain activities where limited market risk is assumed are considered trading for accounting purposes and are executed with the use of a combination of financial instruments including, but not limited to, basis contracts and gas daily contracts. The derivative contracts that are entered into for trading purposes, subject to limits, are recognized on 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.

The following table details the outstanding commodity-related derivatives as of December 31, 2007 and August 31, 2007, respectively:

December 31, 2007

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
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
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(18,362,500)	2008	$ 2,298
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

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August 31, 2007

Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	14,195,262	2007-2009	$ 5,551
Swing Swaps IFERC	Gas	7,282,500	2007-2008	(514)
Fixed Swaps/Futures	Gas	(590,000)	2007-2009	1,298
Forward Physical Contracts	Gas	(6,437,413)	2007-2008	343
Options	Gas	(976,000)	2007-2008	(346)
Forward/Swaps - in Gallons	Propane	8,862,000	2007-2008	777
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(4,922,500)	2007-2008	$ 2,390
Swing Swaps IFERC	Gas	(21,250,000)	2007	(33)
Forward Physical Contracts	Gas		2007	323
Fixed Swaps/Futures	Gas	(10,275,000)	2007	(177)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(10,962,500)	2007-2008	$ 124
Fixed Swaps/Futures	Gas	(11,230,000)	2007-2009	23,078

Estimates related to our gas marketing activities are sensitive to uncertainty and volatility inherent in the energy commodities markets and actual results could differ from these estimates. We also 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 in our trading and non-trading activities, fluctuating commodity prices can impact our financial results and financial position, either favorably or unfavorably.

During the four months ended December 31, 2007, the Partnership discontinued application of hedge accounting in connection with certain derivative financial instruments that were qualified for and designated as cash flow hedges related to forecasted sales of natural gas stored in the Partnership s 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 December 2007. One of the key criteria to achieve hedge accounting under SFAS 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, during the four months ended December 31, 2007, the Partnership recognized previously deferred unrealized gains of $9,186 from the discontinued application of hedge accounting, which is included in the reclassification into earnings from OCI. No such gains or losses were recognized during the four months ended December 31, 2006. The Partnership classified the unrealized gains as costs of products sold in its consolidated statement 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 in the four-month period ending December 31, 2007. For the four-month period ended December 31, 2006, gains or losses related to our interest rate derivatives were reported in interest expense.

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The following table represents interest rate swap derivatives at December 31, and August 31, 2007:

Term	Notional Amount	Type	SFAS 133 Hedge	Fair Value Liability as of December 31, 2007	Fair Value Liability as of August 31, 2007
March 2009	$ 125,000	Pay Fixed 5.14% Receive Float	No	$ 1,530	$ 498

We reclassified into earnings losses of $51 and gains of $228 for the four months ended December 31, 2007 and 2006, respectively, related to interest rate swaps that were previously reported in OCI. We expect gains of $571 to be reclassified into earnings over the next twelve months related to income on interest rate financial instruments currently reported in OCI. The amount ultimately realized, however, could differ as interest rates and the timing of debt issuances change.

The following table represents pre-tax balances in OCI related to interest rate swaps accounted for as cash flow hedges as of December 31 and August 31, 2007:

Date Settled	Term	Notional Amount	Type	Other Comprehensive Income (Loss) as of December 31, 2007	Other Comprehensive Income (Loss) as of August 31, 2007
April 2007	2014	$ 400,000	LIBOR Forward Starting	$ (11,135)	$ (11,562)
June 2006	2016	200,000	Treasury Lock	12,210	12,597
January 2005	2017	100,000	Treasury Lock	(269)	(280)
				$ 806	$ 755

Summary of Derivative Gains and Losses

The following represents gains (losses) on derivative activity for the periods presented:

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
Commodity-related		
Unrealized non-trading gains recognized in cost of products sold related to commodity-related derivative activity, excluding ineffectiveness	$ 4,934	$ 5,194
Ineffective portion of derivatives qualifying for hedge accounting recognized in cost of products sold	8,472	307
Realized non-trading gains related to commodity-related derivatives included in cost of products sold	13,625	15,111
Trading unrealized losses recognized in revenues	(205)	(16,428)
Trading realized gains (losses) recognized in revenues	(2,094)	19,842
Interest rate swaps		
Unrealized losses on interest rate swap included in other income (December 2007) and interest expense (December 2006), excluding ineffectiveness	$ (1,032)	$ (2,072)
Ineffective portion of derivatives qualifying for hedge accounting included in interest expense		26
Realized gains on interest rate swap included in interest expense and other income, net, in 2007, and interest expense in prior periods	38	956

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.

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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.

15. RELATED PARTY TRANSACTIONS:

During the four months ended December 31, 2007, the Operating Partnerships made the following sales to and purchases from affiliates of Enterprise G.P. Holdings, L.P. (Enterprise):

Enterprise Transactions	Product	Volumes (in thousands)	Dollars
Propane Operations - Purchases	Propane - gallons	112,961	$ 175,839
Natural Gas Operations - Sales	NGLs - gallons	3,240	4,726
	Natural Gas - MMBtu	2,036	11,452
	Fees		610
Purchases	Natural Gas Imbalances - MMBtu	313	(911)
	Natural Gas - MMBtu	3,577	23,341
	Fees		311

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

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. The following table summarizes the related party balances with Enterprise on our condensed consolidated balance sheets related to our natural gas operations:

	December 31, 2007	August 31, 2007
Accounts receivable	$ 9,770	$ 2,010
Accounts payable	$ 6,840	$ 4,553
Imbalance payable	$ 6,218	$ 7,100

Our propane operations have accounts receivable from Enterprise of $3,396 as of December 31, 2007. There was no balance receivable from Enterprise for our propane operations at August 31, 2007. Accounts payable to Enterprise for our propane operations were $41,939 and $8,900 as of December 31, 2007 and August 31, 2007, respectively.

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

	December 31, 2007	August 31, 2007
ETP GP	$ 5,113	$ 98
ETE	1,553	1,096
MEP	743	2,291
Energy Transfer Technologies, Ltd.	922	943
Others	2,941	462
Total accounts receivable from related companies excluding Enterprise	$ 11,272	$ 4,890

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The Chief Executive Officer (CEO) of our General Partner, Mr. Kelcy Warren, voluntarily determined that effective October 19, 2007, 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 the cash bonus of $750 for our fiscal year 2007 that had been accrued for him as of August 31, 2007, and decided that he would not accept any future equity awards under our 2004 Unit Plan. In accordance with GAAP, we recorded compensation expense and an offsetting capital contribution of $417 for the four months ended December 31, 2007 as an estimate of the reasonable compensation level for the CEO position, and transferred the $750 accumulated fiscal year 2007 bonus from accrued liabilities to partners capital.

16. REPORTABLE SEGMENTS:

Our financial statements reflect 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

The December 1, 2006 acquisition of Transwestern (see Note 2), resulted in a new reporting segment, our interstate transportation operations. The comparability of the segment operations information is affected by this addition. The volumes and results of operations data for the four months ended December 31, 2007 include the interstate operations for the entire period. However, the volumes and results of operations for the four months ended December 31, 2006 include the interstate operations only since the acquisition date forward. The comparability of the segment data for the four-month period ending December 31, 2007 to the prior period is also affected by the allocation of administrative expenses, as discussed further below.

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.

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general, 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. Effective with the Transwestern acquisition on December 1, 2006, we began allocating 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 four months ended December 31, 2007 were approximately $6,761 to the midstream and intrastate transportation segments, $2,613 to the interstate transportation segment and $5,992 to the propane segment, for a total of approximately $15,366. These amounts were offset by costs allocated to the Partnership from the Operating Partnerships for support services. The amounts allocated to the Partnership, using the MMFC, from the midstream and intrastate transportation and propane segments for the four months ended December 31, 2007 were $2,440 and $850, respectively. No such amounts were allocated to the Partnership from the interstate transportation segment for the four months ended December 31, 2007.

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

	Four Months Ended December 31, 2007	2006
Volumes:		
Midstream		
Natural gas MMBtu/d - sold	1,090,090	968,016
NGLs Bbls/d - sold	25,389	12,458
Transportation and storage		
Natural gas MMBtu/d - transported	8,787,387	4,889,029
Natural gas MMBtu/d - sold	1,259,566	1,379,721
Interstate transportation		
Natural gas MMBtu/d - transported	1,708,477	1,791,437
Retail propane gallons (in thousands)	205,311	214,623
Revenues:		
Midstream	$ 1,166,313	$ 905,392
Eliminations	(664,522)	(451,599)
Intrastate transportation and storage	1,254,401	1,195,871
Interstate transportation	76,000	19,003
Retail propane and other retail propane related	511,258	449,841
All other	6,060	43,958
Total revenues	$ 2,349,510	$ 2,162,466
Cost of Sales:		
Midstream	$ 1,043,191	$ 839,561
Eliminations	(664,522)	(451,599)
Intrastate transportation and storage	964,568	994,511
Retail propane and other retail propane related	325,158	267,338
All other	5,259	40,032
Total cost of sales	$ 1,673,654	$ 1,689,843
Depreciation and Amortization:		
Midstream	$ 13,629	$ 6,434
Intrastate transportation and storage	20,670	16,261
Interstate transportation	12,305	3,191
Retail propane and other retail propane related	24,537	22,520
All other	192	361
Total depreciation and amortization	$ 71,333	$ 48,767

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	Four Months Ended December 31, 2007	2006
Operating Income (Loss):		
Midstream	$ 73,167	$ 41,735
Intrastate transportation and storage	172,120	112,021
Interstate transportation	29,657	11,854
Retail propane and other retail propane related	46,747	49,841
All other	(628)	528
Selling general and administrative expenses not allocated to segments	2,571	(6,091)
Total operating income	$ 323,634	$ 209,888
Other items not allocated by segment:		
Interest expense	$ (66,298)	$ (54,946)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Interest and other income, net	1,061	2,158
Income tax expense	(10,789)	(3,120)
Minority interests		(490)
	(61,810)	(49,443)
Net income	$ 261,824	$ 160,445

	December 31, 2007	August 31, 2007
Total Assets:		
Midstream	$ 1,304,187	$ 801,968
Intrastate transportation and storage	3,976,895	3,534,013
Interstate transportation	1,834,941	1,653,363
Retail propane and other retail propane related	1,778,426	1,593,863
All other	113,712	125,221
Total	$ 9,008,161	$ 7,708,428

	Four Months Ended December 31, 2007	2006
Additions to Property, Plant and Equipment including acquisitions (accrual basis):		
Midstream	$ 414,722	$ 109,408
Intrastate transportation and storage	320,965	254,437
Interstate transportation	167,343	1,261,501
Retail propane and other retail propane related	47,553	30,702
All other	953	517
Total	$ 951,536	$ 1,656,565

17. SUBSEQUENT EVENTS:

On February 5, 2008, ETP entered into a credit agreement providing for a $500,000, 364-day term loan credit facility (the 364-Day Credit Facility). Borrowings under the 364-Day Credit Facility will be used for general corporate purposes. The 364-Day Credit Facility is a single draw term loan with an applicable Eurodollar rate plus 1.000% per annum based on our current rating by the rating agencies or at Base Rate for designated period. We expect to draw the entire amount on or about February 12, 2008. The indebtedness under the 364-Day Credit Facility is unsecured and is not guaranteed by any of our or ETP s subsidiaries. Borrowings under the 364-Day Credit Facility, upon proper notice to the administrative agent, may be prepaid in whole or in part without premium or penalty. The loan agreement related to the 364-Day Credit Facility requires any proceeds received from debt or equity issuance, assets sales, or accordion increases be used to make a mandatory prepayment on the outstanding loan balance. This loan agreement contains covenants that are similar to the covenants of the ETP Credit Facility.

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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 Transition Report on Form 10-Q and our Annual Report on Form 10-K for the fiscal year ended August 31, 2007 filed with the Securities and Exchange Commission (SEC) on October 30, 2007. This transition report on Form 10-Q is being filed due to our change in year end, and covers the transition period that began September 1, 2007 and ended December 31, 2007. Pursuant to Form 8-K.I. Item 5.03, *Amendment to Articles of Incorporation or Bylaws; Change in Fiscal Year*, the data for the four-month period ended December 31, 2006 is presented for comparison purposes. 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 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

The Canyon Gathering System (included in our midstream segment) consists of approximately 1,800 miles of gathering pipeline ranging in diameters from two inches to 16 inches in the Piceance-Uinta Basin of Colorado and Utah and six conditioning plants with an aggregated processing capacity of 90 MMcf/d. The system currently gathers approximately 130,000 MMBtu/d from 1,400 wells and is connected to five major pipeline systems.

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

Our principal operations are conducted in the following reportable segments (see Note 16 to our unaudited condensed consolidated financial statements):

Midstream - Revenue is primarily generated by 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.

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

Analytical Analysis

The comparability of our condensed consolidated financial statements is affected by our 100% acquisition of Transwestern on December 1, 2006 and our purchases of 50% of CCEH in November 2006 (see Note 2 to our condensed consolidated financial statements). The comparability is also 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.

Analysis of Operating Data - Volumes

Midstream

	Four Months Ended December 31,		
	2007	**2006**	**Increase**
Natural gas MMBtu/d - sold	1,090,090	968,016	122,074
NGLs Bbls/d - sold	25,389	12,458	12,931

Natural gas sales volumes increased principally due to more favorable market conditions during the four months ended December 31, 2007 resulting in higher sales volumes conducted by our producer services operations.

The increase in NGL sales volumes is principally due to the completion of our Godley processing plant in October 2006 and the continued expansion of the plant since placing it into service. As of December 31, 2007, the Godley plant had approximately 300,000 MMcf/d of cryoprocessing capacity and 100,000 MMcf/d of refrigeration processing capacity.

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Intrastate Transportation and Storage

	Four Months Ended December 31, 2007	2006	Increase (Decrease)
Natural gas MMBtu/d - transported	8,787,387	4,889,029	3,898,358
Natural gas MMBtu/d - sold	1,259,566	1,379,721	(120,155)

Transported natural gas volumes increased principally due to the increased volumes experienced on the ET Fuel and East Texas Pipeline systems as a result of the completion of the Cleburne to Carthage Pipeline, increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, and the continued effort to secure long-term shipper contracts.

Natural gas sales volumes on the HPL System decreased primarily due to the new CenterPoint contract that commenced on April 1, 2007. Under the previous contract, we sold and delivered natural gas to CenterPoint for a bundled price. Under the terms of the new agreement, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas capacity in our Bammel storage facility.

Interstate Transportation

	Four Months Ended December 31, 2007	2006	Decrease
Natural gas MMBtu/d - transported	1,708,477	1,791,437	(82,960)

The four months ended December 31, 2006 only include volumes transported from the acquisition date of December 1, 2006 to December 31, 2006.

Retail Propane

	Four Months Ended December 31, 2007	2006	Decrease
Retail propane gallons sold (in thousands)	205,311	214,623	(9,312)

Total gallons sold by our retail propane operations decreased due to a combination of below normal degree days, customer conservation, and the slow down of new home construction in our propane markets. The overall weather in our areas of operations during the four months ended December 31, 2007 was 2.9% warmer than the four months ended December 31, 2006 and 9.8% warmer than normal.

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Analysis of Results of Operations

Consolidated Results

	Four Months Ended December 31, 2007	2006	Change
Revenues	$ 2,349,510	$ 2,162,466	$ 187,044
Cost of sales	1,673,654	1,689,843	(16,189)
Gross margin	675,856	472,623	203,233
Operating expenses	221,757	173,365	48,392
Selling, general and administrative	59,132	40,603	18,529
Depreciation and amortization	71,333	48,767	22,566
Operating income	323,634	209,888	113,746
Interest expense	(66,298)	(54,946)	(11,352)
Equity in earnings (losses) of affiliates	(94)	4,743	(4,837)
Gain on disposal of assets	14,310	2,212	12,098
Other income, net	1,061	2,158	(1,097)
Income tax expense	(10,789)	(3,120)	(7,669)
Minority interests		(490)	490
Net income	$ 261,824	$ 160,445	$ 101,379

See the detailed discussion of revenues, costs of sales, margin and operating expense by operating segment below.

Interest Expense. Interest expense increased $11.4 million principally due to a net $13.8 million increase in interest expense related to borrowings on the Partnership s Senior Notes and the revolving credit facility and $0.5 million of interest on borrowings related to the Transwestern acquisition. Partnership borrowings increased primarily due to the financing of our growth capital expenditures and the Canyon acquisition. The increased interest expense was offset by $2.0 million of unrealized losses related to non-hedged interest rate swaps included in interest expense for the four months ended December 31, 2006. Unrealized gains and losses related to non-hedged interest rate swaps were included in other income, net for the four months ended December 31, 2007. The increase in interest expense was also offset by propane related interest which decreased $2.0 million due primarily to the scheduled debt payments that have occurred between the four-month periods.

Equity in Earnings of Affiliates. The decrease in equity in earnings (losses) of affiliates was due primarily to $5.1 million of equity income from our 50% ownership of CCEH for the month of November 2006. We redeemed our investment in CCEH in connection with our Transwestern acquisition on December 1, 2006. We do not include earnings from equity method unconsolidated affiliates in our measurement of operating income because such earnings have not been significant historically.

Gain on Sale of Assets. On October 1, 2007 we sold our 60% interest in a Canadian wholesale fuel business for a gain of $10.2 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.

The increase in income tax expense was primarily related to $3.9 million recorded for the four months ended December 31, 2007 of Texas margin tax that was not effective until January 1, 2007 and $3.9 million of taxes on the gain on the sale of our interest in a Canadian wholesale fuel business.

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Segment Operating Results

Operating income by segment is as follows:

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006	Change
Midstream	$ 73,167	$ 41,735	$ 31,432
Intrastate Transportation and Storage	172,120	112,021	60,099
Interstate Transportation	29,657	11,854	17,803
Retail Propane	46,747	49,841	(3,094)
Other	(628)	528	(1,156)
Unallocated selling, general and administrative expenses	2,571	(6,091)	8,662
Operating income	$ 323,634	$ 209,888	$ 113,746

We do not believe the Other operating income is material for further disclosure or discussion.

Unallocated Selling, General and Administrative Expenses. Prior to December 2006, the selling, general and administrative expenses that relate to the general operations of the Partnership were not allocated to our segments. In conjunction with the Transwestern acquisition, selling, general and administrative expenses are now allocated monthly to the Operating Partnerships using the Modified Massachusetts Formula Calculation (MMFC). 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. For the four months ended December 31, 2007, a net $12.1 million allocation to the Operating Partnerships exceeded total incurred costs.

Midstream

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006	Change
Revenues	$ 1,166,313	$ 905,392	$ 260,921
Cost of sales	1,043,191	839,561	203,630
Gross margin	123,122	65,831	57,291
Operating expenses	17,633	11,710	5,923
Selling, general and administrative	18,693	5,952	12,741
Depreciation and amortization	13,629	6,434	7,195
Segment operating income	$ 73,167	$ 41,735	$ 31,432

Gross Margin. Midstream s gross margin increased by $57.3 million primarily due to the following factors:

Increases in processing margin of $37.6 million and fee-based revenue of $17.9 million from our gathering and processing assets. The increase was due to incremental volumes from the completion of our Godley plant in October 2006, the continued expansion of the plant since placing it into service, and the acquisition of three gathering systems during the first six months of the 2007 fiscal year. In addition, our midstream assets benefited from favorable market conditions to process and extract NGLs during the four months ended December 31, 2007. Due to changes in the contract structures at our Godley plant in November 2007, arrangements for which we had been recognizing the increased margin from favorable conditions will convert to long-term fee-based arrangements. As such, we expect margin from processing at our Godley plant to be more predictable and less sensitive to commodity price volatility;

Increase in non-trading margin from our marketing activities of $1.0 million. Market conditions resulted in higher sales volumes conducted by our producer services operations;

Decrease in net trading revenues of $5.2 million; and,

Canyon Gathering System The acquisition of the Canyon Gathering System on October 5, 2007 contributed approximately $5.6 million of incremental margin for the four months ended December 31, 2007.

Operating Expenses. Midstream operating expenses increased $5.9 million, primarily driven by increased employee-related costs such as salaries, incentive compensation and healthcare costs of $2.2 million, increased compressor rentals of $1.5 million, and increased pipeline and compressor maintenance expense of $0.7 million. The increases were principally due to the gathering system acquisitions in fiscal 2007, the start up and continued expansion of the Godley plant, and the Canyon acquisition.

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Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses increased $12.7 million which was attributable to $9.2 million in increased legal fees principally related to regulatory matters, a $4.2 million allocation of parent company administrative expenses for overhead costs which previously had not been allocated in 2006, and a $1.9 million increase in employee-related costs such as salaries, incentive compensation and healthcare costs. These factors were offset by a $5.8 million increase of general and administrative expenses allocated to the transportation segment. The allocation of general and administrative expenses between the midstream and the intrastate transportation and storage segments is based on the MMFC and is intended to fairly present the segment s operating results.

Depreciation and Amortization. Midstream depreciation and amortization expense increased $7.2 million principally due to additions to property and equipment including the completion and continued expansion of our Godley plant, and the acquisition of certain gathering system in December of 2006.

Intrastate Transportation and Storage

	Four Months Ended December 31, 2007	2006	Change
Revenues	$ 1,254,401	$ 1,195,871	$ 58,530
Cost of sales	964,568	994,511	(29,943)
Gross margin	289,833	201,360	88,473
Operating expenses	76,428	56,452	19,976
Selling, general and administrative	20,615	16,626	3,989
Depreciation and amortization	20,670	16,261	4,409
Segment operating income	$ 172,120	$ 112,021	$ 60,099

Gross Margin. Intrastate transportation and storage gross margin increased by $88.5 million, principally due to the following factors:

Volumes. Overall volumes on our transportation pipelines were higher due to the completion of the Clebourne to Carthage Pipeline, increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, continued efforts to secure long-term shipper contracts, and the completion of various growth projects subsequent to December 31, 2006. Transportation fees increased approximately $53.2 million. Retention revenue increased approximately $29.7 million due to increased volumes transported through our transportation pipelines;

Increase in processing margin of $8.6 million from our HPL system. Processing margins generated from our HPL system benefited from favorable market conditions to process and extract NGLs during the four months ended December 31, 2007; and

Net decrease in storage margins of $9.4 million. During the four months ended December 31, 2006, we recognized approximately $27.0 million of margin on 13 Bcf of gas sold from our Bammel facility. Due to market conditions, there were no withdrawals in the same period in 2007; however, we did recognize $9.2 million in gains from the discontinuation of hedge accounting resulting from our determination that originally forecasted sales of natural gas from the Partnership s Bammel storage facility were no longer probable to occur by the specified time period, or within an additional two-month time period thereafter. In addition, fee-based storage revenues increased $8.4 million primarily due to the new Centerpoint contract which commenced on April 1, 2007 in which Centerpoint contracted for 10 Bcf of working gas capacity in our Bammel storage facility.

Operating Expenses. Intrastate transportation and storage operating expenses increased $20.0 million primarily due to an increase of $11.4 million in fuel consumption, an increase of $4.5 million in electricity costs, an increase of $6.1 million in compressor and pipeline maintenance, and an increase of $2.0 million in employee related costs such as salaries, incentive compensation and healthcare costs. These increases were offset by a $2.8 million decrease in compressor rentals and a $2.9 million decrease in professional fees related to the EMS contract buyout in September 2007.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased $4.0 million principally due to an increase in general and administrative expenses allocated from the midstream segment as noted above.

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Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased $4.4 million principally due to additions to property and equipment most notably the Clebourne to Carthage Pipeline.

Interstate Transportation

	Four Months Ended December 31, 2007	2006	Change
Revenues	$ 76,000	$ 19,003	$ 56,997
Operating expenses	23,922	1,396	22,526
Selling, general and administrative	10,116	2,562	7,554
Depreciation and amortization	12,305	3,191	9,114
Segment operating income	$ 29,657	$ 11,854	$ 17,803

The increase in all categories was due to the acquisition of 100% of Transwestern on December 1, 2006.

Retail Propane

	Four Months Ended December 31, 2007	2006	Change
Retail propane revenues	$ 471,494	$ 409,821	$ 61,673
Other retail propane related revenues	39,764	40,020	(256)
Retail propane cost of sales	315,698	256,994	58,704
Other retail propane related cost of sales	9,460	10,344	(884)
Gross margin	186,100	182,503	3,597
Operating expenses	102,537	101,508	1,029
Selling, general and administrative	12,279	8,634	3,645
Depreciation and amortization	24,537	22,520	2,017
Segment operating income	$ 46,747	$ 49,841	$ (3,094)

Revenues. Retail propane revenues increased $61.7 million mainly due to increased sale prices driven by the increased cost of fuel. This increase was offset by 9.8% warmer than normal weather and 2.9% warmer weather than the same period last year.

Costs of Sales. Retail propane cost of sales increased by $58.7 million mainly related to the increase in overall cost of fuel to the company offset by the decrease in gallons sold. On an average, fuel costs were approximately $0.35/gallon higher.

Gross Margin. Overall gross margins increased $3.6 million even though gallon sales decreased. The propane margin remained strong despite warmer weather conditions and higher fuel prices. Optimization of the margins is influenced by market opportunities, independent competitors and concerns for long term retention of customers.

Operating Expenses. Operating expenses increased by $1.0 million. Included in these operating expenses were increases related to higher vehicle fuel costs and other vehicle expenses, offset by the cost conservation efforts of the retail operations and the delay in hiring seasonal staff due to the warmer weather.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses was primarily due to increased administrative expense allocations. Effective with the Transwestern acquisition in December 2006, an allocation of general and administrative expenses based on the MMFC is now made to the operating partnerships, which increased the retail propane selling, general and administrative expenses by a net $5.1 million for the four months ended December 31, 2007. This increase from the allocation of expenses was offset by the reduction of certain personnel costs at the propane operating partnerships.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense was primarily due to the depreciation and amortization of assets and amortizable intangibles added through acquisitions made after December 31, 2006.

Income Taxes

As a limited partnership we generally are not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the four months ended December 31, 2007 and 2006, our non-qualifying income was not expected to, or did not, exceed the statutory limit.

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law s effective date of January 1, 2007. For the four months ended December 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $3.9 million. There is no comparable state tax expense for the period ended December 31, 2006.

Income tax expense consists of the following current and deferred amounts:

	Four Months Ended December 31, 2007	2006
Current provision:		
Federal	$ 2,990	$ 4,797
State	5,705	557
Total	8,695	5,354
Deferred provision (benefit):		
Federal	1,482	(1,972)
State	612	(262)
Total	2,094	(2,234)
Total tax provision	$ 10,789	$ 3,120
Effective tax rate	3.96%	1.91%

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. The difference between the statutory rate and the effective rate is summarized as follows:

	Four Months Ended December 31, 2007	2006
Federal statutory tax rate	35.00%	35.00%
State income tax rate net of federal benefit	1.82%	3.48%
Earnings not subject to tax at the Partnership level	(32.86)%	(36.57)%
Effective tax rate	3.96%	1.91%

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 generally are expected to consist of:

- maintenance capital expenditures for the intrastate and interstate operations, which include capital expenditures made to connect additional wells to our natural gas systems in order to maintain or increase throughput on existing assets, for which we expect to expend approximately $70.0 million in the next calendar year and capital expenditures to extend the useful lives of our propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet, for which we expect to expend approximately $35.0 million in the next calendar year;

- growth capital expenditures, mainly for constructing new pipelines, processing plants, treating plants and compression for the midstream and intrastate transportation and storage segment for which we expect to expend approximately $950.0 million in the next calendar year. We also expect to spend approximately $790.0 million in our interstate segment for constructing new pipelines and pipeline expansion and approximately $30.0 million for customer propane tanks in the next calendar year; and

- acquisition capital expenditures including acquisition of new pipeline systems and propane operations.

We believe that cash generated from the operations of our businesses will be sufficient to meet anticipated maintenance capital expenditures. We generally fund our capital requirements by cash flows from operating activities and, to the extent that our future capital requirements exceed cash flows from operating activities, from the following sources:

- maintenance capital expenditures may be financed by the proceeds of borrowings under the existing credit facilities described below, which would generally be expected to be repaid by subsequent seasonal reductions in inventory and accounts receivable;

- growth capital expenditures may be financed by the proceeds of borrowings under credit facilities, long-term debt, the issuance of additional common units or a combination thereof; and

- acquisition capital expenditures may be financed by the proceeds of borrowings under the existing credit facilities, other lines of credit, long-term debt, the issuance of additional Common Units or a combination thereof.

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 calendar 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 four months ended December 31, 2007, was $245.7 million as compared to cash provided by operating activities of $420.9 million for the four months ended December 31, 2006. The net cash provided by operations for the four months ended December 31, 2007 consisted of net income of $261.8 million, non-cash charges of $70.9 million, principally depreciation and amortization, unit-based compensation expense, and gain on disposal of assets and a decrease in cash from changes in operating assets and liabilities of $87.0 million. Various components of operating assets and liabilities changed significantly from the prior period due to factors such as the change in value of price risk management assets and liabilities, variance in the timing of accounts receivable collections, payments on accounts payable, and the timing of the purchase and sale of inventories related to the propane and intrastate transportation and storage operations.

Investing Activities. Cash used in investing activities during the four months ended December 31, 2007 of $995.9 million was comprised primarily of cash paid for acquisitions of $337.1 million and $604.3 million invested for growth capital expenditures, including changes in accruals of $5.6 million. Total growth capital expenditures consists of $422.9 million for our intrastate operations and $167.1 million for our interstate operations, and $14.3 million for our propane operations. We also incurred $49.0 million in maintenance expenditures needed to sustain operations of which $21.4 million related to intrastate operations, $12.9 million related to interstate operations, and $14.7 million to propane operations.

Financing Activities. Cash provided by financing activities was $738.0 million for the four months ended December 31, 2007. We received $234.9 million in net proceeds from an equity offering (see Note 12 to our condensed consolidated financial statements). Proceeds from the equity offering and funds from the ETP Credit Facility were used to repay the $310.0 million ETP Term Loan Facility related to the Canyon acquisition (discussed below). We had a net increase in our debt level of $666.4 million primarily under the ETP Credit Facility (including the swingline loan option) to partially repay the ETP Term Loan Facility, to fund our growth capital expenditures and for general partnership purposes. During the four months ended December 31, 2007, we paid distributions of $176.0 million to our partners related to the fourth quarter of our fiscal year 2007.

Financing and Sources of Liquidity

During fiscal year 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission 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 Securities and Exchange Commission 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.

On December 18, 2007, the Partnership sold in a public offering 5 million common units representing limited partner interests at $48.81 per common unit. ETP used the offering proceeds of $234.9 million, net of issuance costs, to repay a portion of the outstanding debt under the ETP Term Loan Facility (discussed below). The remaining balance on the ETP Term Loan Facility was repaid with borrowings from the ETP Credit Facility. The offering closed on December 18, 2007. ETP also granted the underwriters a 30-day option to purchase up to an aggregate of 750,000 additional common units to cover over-allotments, if any. The underwriters exercised their option in full and ETP issued 750,000 additional common units at $48.81 per common unit on January 8, 2008. The proceeds of $35.2 million, net of offering costs, were used to repay borrowings from the ETP Credit Facility.

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Description of Indebtedness

Our indebtedness as of December 31, 2007 consists of $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 maintain separate credit facilities for Transwestern and HOLP. The terms of our indebtedness and that of our Operating Partnerships are described in more detail in our Annual Report on Form 10-K for fiscal 2007 filed with the Securities and Exchange Commission on October 30, 2007.

ETP Term Loan Facility

On December 18, 2007, we used proceeds received from an equity offering (see Note 12 to our condensed consolidated financial statements) and funds from the ETP Credit Facility to fully repay the ETP Term Loan Facility, a $310.0 million, 364-day term loan credit facility we executed on October 5, 2007 primarily to finance the Canyon acquisition. The ETP Term Loan Facility was a single draw term loan with an applicable Eurodollar rate plus 0.600% per annum based on our current rating by the rating agencies or at Base Rate for designated period.

ETP Credit Facility

On July 20, 2007, we entered into a credit agreement providing for the ETP Credit Facility, a $2.0 billion revolving credit facility that is expandable to $3.0 billion at our option (subject to the approval of the administrative agent under the Amended and Restated Credit Agreement, which approval is not to be unreasonably withheld) 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 under the ETP Credit Facility). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The ETP Credit Facility has a swingline loan option of which borrowings and aggregate principal amounts shall not exceed the lesser of (i) the aggregate commitments ($2.0 billion unless expanded to $3.0 billion) less the sum of all outstanding revolving credit loans and the letter of credit obligation and (ii) the swingline commitment. The aggregate amount of swingline loans in any borrowing shall not be subject to a minimum amount or increment. The indebtedness under the ETP Credit Facility is prepayable at any time at the Partnership s option without penalty. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating (0.11% based on our current rating) with a maximum fee of 0.125%.

As of December 31, 2007, there was a balance of $1.6 billion in revolving credit loans (including $273.9 million in swingline loans) and $61.3 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2007, was 5.746%. The total amount available under the ETP Credit Facility, as of December 31, 2007, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $311.7 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.

ETP 364-Day Credit Facility

On February 5, 2008, ETP entered into a credit agreement providing for a $500.0 million, 364-day term loan credit facility (the 364-Day Credit Facility). Borrowings under the 364-Day Credit Facility will be used for general corporate purposes. The 364-Day Credit Facility is a single draw term loan with an applicable Eurodollar rate plus 1.000% per annum based on our current rating by the rating agencies or at Base Rate for designated period. We expect to draw the entire amount on or about February 12, 2008. The indebtedness under the 364-Day Credit Facility is unsecured and is not guaranteed by any of our or ETP s subsidiaries. Borrowings under the 364-Day Credit Facility, upon proper notice to the administrative agent, may be prepaid in whole or in part without premium or penalty. The loan agreement related to the 364-Day Credit Facility requires any proceeds received from debt or equity issuance, assets sales, or accordion increases be used to make a mandatory prepayment on the outstanding loan balance. This loan agreement contains covenants that are similar to the covenants of the ETP Credit Facility.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the HOLP Facility) is available to HOLP through June 30, 2011 which may be expanded to $150.0 million. The HOLP Facility has a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the HOLP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the HOLP Facility credit agreement, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Facility. As of December 31, 2007, there was $15.0 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 Facility. There were outstanding Letters of Credit of $1.0 million at December 31, 2007. The weighted average interest rate on the total amount outstanding at December 31, 2007, was 5.97%. The sum of the loans made under the HOLP 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 Facility. The amount available at December 31, 2007 was $59.0 million.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes (collectively, the HOLP Notes). In addition to the stated interest rate for the HOLP Notes, we are required to pay an additional 1% per annum on the outstanding balance of the HOLP Notes at such time as the HOLP Notes are not rated investment grade status or higher. As of December 31, 2007 the HOLP Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

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.

On October 15, 2007, we paid a quarterly distribution of $0.825 per Common Unit ($3.30 per unit on an annualized basis) to Unitholders of record at the close of business on October 5, 2007. 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).

In connection with the previously announced change in the Partnership s year end from August 31 to December 31, the Partnership amended its partnership agreement to provide that, in lieu of making a cash distribution for the three-month period ended November 30, 2007, the Partnership will make a cash distribution for the four-month period ended December 31, 2007. Based on this change in timing, on January 18, 2008 ETP s Board of Directors approved the payment of a four-month distribution to ETP Unitholders of $1.125 per unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This represents an increase of $0.075 per unit on an annualized basis. The four-month distribution will be paid on February 14, 2008 to Unitholders of record as of the close of business on February 1, 2008.

After this distribution payment, the Partnership will continue to make quarterly distributions on a three-month basis as we have done in the past with the next scheduled quarterly distribution payments occurring in mid May, mid August, and mid November.

New Accounting Standards

See Note 3 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 Transition 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.

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Commodity-related Derivatives

Our commodity-related price risk management assets and liabilities as of December 31, 2007 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
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
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(18,362,500)	2008	$ 2,298
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

Sensitivity Analysis

The table below summarizes our commodity-related financial derivative instruments and fair values as of December 31, 2007. 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	(8,522,500)	$ (4,029)	$ 690
Swing Swaps IFERC	(4,640,000)	(1,515)	166
Fixed Swaps/Futures	(40,107,500)	41,143	29,841
Forward Physical Contracts	(17,847,140)	(1,063)	941
Options	(670,000)	(161)	75
Propane Forwards/Swaps (in Gallons)	9,282,000	3,319	1,478
Trading Derivatives			
Basic Swaps IFERC/NYMEX	(18,362,500)	2,298	815

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 percent 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 percent change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10 percent 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

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facilities will also increase. At December 31, 2007, we had $1.64 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 consolidated statement 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 $14.9 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 14 to our condensed consolidated financial statements.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a 15(e) and 15d 15(e) of the Securities Exchange Act of 1934, as amended) as of December 31, 2007. Our management, including the Chief Executive Officer and the Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. The inherent limitations in all control systems include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Based upon the evaluation, our management, including the Chief Executive Officer and the Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures are adequate and effective to ensure that information required to be disclosed by us in our periodic filings under the Securities and Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

Changes in Internal Control over Financial Reporting

We closed the acquisition of Transwestern on December 1, 2006 and have begun the integration of the internal control structure of Transwestern into our processes and controls. We converted Transwestern s accounting system to our accounting system effective November 1, 2007 and are continuing to implement our internal control structure over Transwestern s operations.

Other than Transwestern, 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 four months ended December 31, 2007 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 the year ended August 31, 2007 and Note 13 - Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Condensed Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Form 10-Q for the four-month period ended December 31, 2007.

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ITEM 1A. RISK FACTORS

In addition to the risks described in our Annual Report on Form 10-K for the year ended August 31, 2007, we are subject to the following additional risks:

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 dates 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 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 Hub and the Katy Hub near Houston, Texas. 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 negotiated rates, 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 rates would be limited to sales of natural gas to retail customers (such as utilities and other end users) and sales from our own production, and any other sales of natural gas by us would be required to be made at prices that would be subject to FERC approval. Also 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 by attempting to manipulate natural gas prices in the Houston Ship Channel. It is alleged that such manipulation was attempted during the period from late September through early December 2005 to allow us to benefit financially from our commodities derivatives positions.

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. 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. 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. In its lawsuit, the CFTC is seeking civil penalties of $130 thousand per violation, or three times the profit gained from each violation, and other ancillary relief. The CFTC has not specified the number of alleged violations or the amount of alleged profit related to the matters specified in its complaint. On October 15, 2007, ETP filed a motion to dismiss in the United State District Court for the Northern District of Texas on the basis that the CFTC has not stated a valid cause of action under the Commodity Exchange Act.

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 and CFTC hold substantial enforcement authority. At this time, we are unable to predict the final outcome of these matters.

In addition to the FERC and CFTC legal actions, 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 and CFTC 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, and seek unspecified direct, indirect, consequential and exemplary damages. 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. One of the producers also seeks to intervene in the FERC proceeding, alleging that it is entitled to a FERC-ordered refund of $5.9 million, plus interest and costs. This producer has also filed a complaint at FERC against us and ETE requesting an agency hearing and claiming that we and ETE violated the NGA by failing to make sales for resale at negotiated rates; intentionally engaged in market manipulation; knowingly submitted misleading information to Platts; and caused damages to the producer group in the amount of $5.9 million. This producer has requested refunds and other remedies. On December 20, 2007, the FERC denied this producer s request to intervene in the FERC proceeding and on February 6, 2008 the FERC dismissed this producer s complaint.

In addition, 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 Commodity Exchange Act (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 also violated the CEA because we knowingly aided and abetted violations of the CEA. This action alleges that this 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 plaintiff and all other members of the putative class who purchased and/or sold natural gas futures and options contracts on NYMEX during the class period. The class action complaint consolidated two class actions which were pending against us. Following the consolidation order, the plaintiffs who had filed these two earlier class actions filed the consolidated complaint. They have requested certification of their suit as a class action, 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.

We are expensing the legal fees, consultants fees and related 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 existing 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.

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.

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ITEM 6. EXHIBITS

(a) Exhibits

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

	Exhibit Number	Description
(1)	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.
(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.
(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.

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	Exhibit Number	Description
(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.
(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.
(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.

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		Exhibit Number	Description
(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.
(45)	**	10.6.6	Amended and Restated 2004 Unit 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.
(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.

	Exhibit Number	Description
(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.

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(10) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.
(11) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2001.
(13) 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.

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(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.

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SIGNATURE

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

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P.,

its General Partner

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

Date: February 11, 2008

By: /s/ Brian J. Jennings
Brian J. Jennings
(Chief Financial Officer duly authorized to sign on behalf of the registrant)

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