Energy Transfer Partners, L.P.
Form 10-Q
May 12, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Quarterly Period Ended March 31, 2008

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition Period from ______ to ______

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**73-1493906**
(state or other jurisdiction or	**(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 large accelerated filer, accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

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

At May 9, 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 Quarterly Report on Form 10-Q as well as the Partnership s Report on Form 10-K as of August 31, 2007 filed with the Securities and Exchange Commission 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)

	March 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 122,260	$ 56,467
Marketable securities	13,651	3,002
Accounts receivable, net of allowance for doubtful accounts	1,062,620	822,027
Accounts receivable from related companies	32,491	24,438
Inventories	116,160	361,954
Deposits paid to vendors	60,475	42,273
Prepaid expenses and other current assets	107,555	99,798
Total current assets	1,515,212	1,409,959
PROPERTY, PLANT AND EQUIPMENT, net	6,897,297	6,433,788
ADVANCES TO AND INVESTMENT IN AFFILIATES	1,253	86,167
GOODWILL	743,383	728,109
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	365,939	350,138
Total assets	$ 9,523,084	$ 9,008,161

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)

	March 31, 2008	December 31, 2007
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 785,244	$ 672,388
Accounts payable to related companies	26,197	48,483
Exchanges payable	43,533	40,382
Customer advances and deposits	41,056	75,831
Accrued and other current liabilities	155,658	180,465
Accrued capital expenditures	152,954	87,622
Interest payable	45,220	63,254
Current maturities of long-term debt	47,213	47,036
Total current liabilities	1,297,075	1,215,461
LONG-TERM DEBT, less current maturities	4,640,280	4,297,264
DEFERRED INCOME TAXES	106,837	102,762
OTHER NON-CURRENT LIABILITIES	14,654	13,483
COMMITMENTS AND CONTINGENCIES (Note 12)		
Total liabilities	6,058,846	5,628,970
PARTNERS CAPITAL:		
General Partner	138,619	160,193
Limited Partners:		
Common Unitholders (142,819,957 and 142,069,957 units authorized, issued and outstanding at March 31, 2008 and December 31, 2007, respectively)	3,327,792	3,192,092
Class E Unitholders (8,853,832 units authorized, issued and outstanding held by subsidiary and reported as treasury units)		
	3,466,411	3,352,285
Accumulated other comprehensive income (loss), per accompanying statements	(2,173)	26,906
Total partners capital	3,464,238	3,379,191
Total liabilities and partners capital	$ 9,523,084	$ 9,008,161

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Three Months Ended	
	March 31, 2008	February 28, 2007
REVENUES:		
Natural gas operations	$ 2,007,847	$ 1,492,838
Retail propane	598,138	499,252
Other	33,386	70,390
Total revenues	2,639,371	2,062,480
COSTS AND EXPENSES:		
Cost of products sold natural gas operations	1,577,268	1,138,709
Cost of products sold retail propane	392,555	304,634
Cost of products sold other	9,895	42,473
Operating expenses	178,970	133,809
Depreciation and amortization	58,828	45,360
Selling, general and administrative	48,369	39,133
Total costs and expenses	2,265,885	1,704,118
OPERATING INCOME	373,486	358,362
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(55,549)	(40,772)
Equity in earnings (losses) of affiliates	74	(514)
Loss on disposal of assets	(1,451)	(3,229)
Other income, net	17,637	1,423
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	334,197	315,270
Income tax expense	5,862	3,300
INCOME BEFORE MINORITY INTERESTS	328,335	311,970
Minority interests		(856)
NET INCOME	328,335	311,114
GENERAL PARTNER S INTEREST IN NET INCOME	74,364	60,567
LIMITED PARTNERS INTEREST IN NET INCOME	$ 253,971	$ 250,547
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.34	$ 1.33
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	142,762,265	136,977,139
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.34	$ 1.33

DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	143,197,800	137,297,706

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)

	Three Months Ended	
	March 31, 2008	February 28, 2007
Net income	$ 328,335	$ 311,114
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	(22,691)	(121,511)
Change in value of derivative instruments accounted for as cash flow hedges	(6,221)	75,953
Change in value of available-for-sale securities	(167)	1,421
Comprehensive income	$ 299,256	$ 266,977
Reconciliation of Accumulated Other Comprehensive Income (Loss), net of tax		
Balance, beginning of period	$ 26,906	$ 59,603
Current period reclassification to earnings	(22,691)	(121,511)
Current period change in value	(6,388)	77,374
Balance, end of period	$ (2,173)	$ 15,466
Components of Accumulated Other Comprehensive Income (Loss), net of tax		
Commodity related hedges	$ (3,012)	$ 15,460
Interest rate hedges	521	(1,497)
Available-for-sale securities	318	1,503
Balance, end of period	$ (2,173)	$ 15,466

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 THREE MONTHS ENDED MARCH 31, 2008

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders
Balance, December 31, 2007	$ 160,193	$ 3,192,092
Distributions to partners	(90,885)	(160,672)
Issuance of units in public offering		34,984
General Partner capital contribution	747	
Contribution receivable from General Partner	(5,806)	
Tax effect of remedial income allocation from tax amortization of goodwill		(975)
Non-cash executive compensation	6	306
Unit-based compensation expense		8,086
Net income	74,364	253,971
Balance, March 31, 2008	$ 138,619	$ 3,327,792

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)

	Three Months Ended March 31, 2008	February 28, 2007
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 383,944	$ 443,443
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(40,753)	(50,246)
Capital expenditures, net of contributions in aid of construction costs	(452,660)	(305,817)
(Advances to) repayments from affiliates, net	63,534	(1,572)
Proceeds from the sale of assets	10,433	11,681
Net cash used in investing activities	(419,446)	(345,954)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	2,995,405	901,715
Principal payments on debt	(2,658,498)	(797,109)
Net proceeds from issuance of Limited Partner Units	34,984	
Distributions to partners	(251,557)	(160,452)
Debt issuance costs	(19,039)	(315)
Net cash provided by (used in) financing activities	101,295	(56,161)
INCREASE IN CASH AND CASH EQUIVALENTS	65,793	41,328
CASH AND CASH EQUIVALENTS, beginning of period	56,467	34,746
CASH AND CASH EQUIVALENTS, end of period	$ 122,260	$ 76,074

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

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

(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 2007, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners, L.P., and subsidiaries (collectively, we or the Partnership) as of March 31, 2008 and for the three-month periods ended March 31, 2008 and February 28, 2007, have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim consolidated financial information and pursuant to the rules and regulations of the 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 March 31, 2008, and the Partnership s results of operations and cash flows for the three-month periods ended March 31, 2008 and February 28, 2007, respectively. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership s Annual Report on Form 10-K for the fiscal year ended August 31, 2007, as filed with the SEC on October 30, 2007, and the Partnership s Report on Form 8-K as of December 31, 2007 and for the four-month transition period then ended, filed with the SEC on March 19, 2008.

In November 2007, we filed a Form 8-K indicating that our Limited Partnership Agreement had been amended to change our fiscal year end to the calendar year. Thus, our new year began on January 1, 2008. The Partnership completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the three-month period ended March 31, 2008 and the three-month period ended February 28, 2007 (the three-month period of the previous fiscal year most nearly comparable to the three-month period ended March 31, 2008).

We did not recast the financial data for the prior fiscal period because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Furthermore, we believe the information and data of the three-month period ended February 28, 2007 is comparable to what would have been reported for the three-month period ended March 31, 2007 if we had recast the prior period information. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the three-month period ended February 28, 2007 to the period ended March 31, 2008 are substantially similar to what would have been reflected had we recast the information for the period ended March 31, 2007.

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;

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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.

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

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

The Canyon acquisition was accounted for under the purchase method of accounting in accordance with FASB Statement No. 141, *Business Combinations*, (SFAS 141), 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

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

We expect to finalize the purchase price allocation for the Canyon acquisition in the third quarter of 2008.

During the three months ended March 31, 2008 we made a purchase price adjustment for a contingent payment associated with a natural gas gathering system in north Texas purchased in September 2006. The purchase and sale agreement had a contingent payment not to exceed $25.0 million which was to be determined eighteen months after the closing date. The contingent payment of $8.7 million was recorded as an adjustment to goodwill in the midstream segment.

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

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

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month s financial statements. Management believes that the operating results estimated for the three months ended March 31, 2008 and February 28, 2007 represent the actual results in all material respects.

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

Significant Accounting Policies

Financial Assets and Liabilities at Fair Value

We adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurement*, (SFAS 157) effective January 1, 2008. SFAS 157 provides a definition of fair value, establishes a fair value framework and hierarchy under GAAP and provides for expanded disclosures of fair value measurements. SFAS 157 does not require any new fair value measurements other than those established by other GAAP requirements.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our condensed consolidated balance sheets. In accordance with SFAS 157, we determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible Level as defined in SFAS 157. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter commodity derivatives entered into directly with third parties Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. Level 3 utilizes significant unobservable inputs. We currently do not have any fair value measurements that require the use of unobservable inputs in our fair value measurements and therefore do not have any assets or liabilities considered as Level 3 valuations as defined by SFAS 157. See Note 13 for additional information and detail of our commodity and interest rate derivative fair value assets and liabilities.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated pipeline construction and production well tie-ins. Contributions in aid of construction costs (CIAC) are netted against our project costs as they are received, and the excess of any CIAC which exceeds our projects costs is recognized as other income in the period in which it was realized. During the three months ended March 31, 2008 and February 28, 2007, $33.1 million and $4.0 million of CIAC was received and netted against our project costs, respectively. During the three months ended March 31, 2008, we received a reimbursement of $40.0 million from Trunkline Gas Company, LLC related to an

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extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million which is recorded in other income. The total CIAC recorded to other income was $7.7 million and $0.1 million for the three months ended March 31, 2008 and February 28, 2007, respectively.

New Accounting Standards

FASB Staff Position (FSP) SFAS 157-2, *Effective Date of FASB Statement No. 157 (FSP 157-2)*. FSP 157-2 defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). An entity that has issued interim or annual financial statements reflecting the application of the measurement and disclosure provisions of SFAS 157 prior to February 12, 2008, must continue to apply all provisions of SFAS 157. We are currently evaluating the impact of our adoption of FSP 157-2 effective January 1, 2009 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). SFAS 158 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. We did not elect the fair value option provisions upon adoption of SFAS 159 on January 1, 2008.

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;
- Restructuring costs associated with a business combination will generally be expensed subsequent to the acquisition date; and
- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date generally will affect income tax expense.

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

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. We do not anticipate a significant impact from a financial perspective, however, the impact on the presentation of our financial information could be significant.

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

FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities An Amendment of FASB Statement No. 133* (SFAS 161). Issued in March, 2008, SFAS 161 requires enhanced disclosures about an entity s derivative and hedging activities and thereby improves the transparency of financial reporting by requiring that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. Thus, SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement has the same scope as SFAS 133, and accordingly applies to all entities. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We are currently evaluating the impact of our adoption of this statement effective January 1, 2009 on our consolidated financial statements.

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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:

	Three Months Ended	
	March 31, 2008	**February 28, 2007**
Net income	$ 328,335	$ 311,114
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	58,828	45,360
Amortization of finance costs charged to interest	1,074	1,317
Provision for loss on accounts receivable	1,204	461
Non-cash compensation on unit grants	8,086	2,907
Non-cash executive compensation	312	
Deferred income taxes	2,857	(2,523)
Loss on disposal of assets	1,451	3,229
Distributed earnings of affiliates, net	1,651	514
Minority interests and other		966
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	(248,114)	(99,091)
Accounts receivable from related companies	(12,805)	(29)
Inventories	248,217	305,853
Deposits paid to vendors	(18,202)	46,258
Exchanges receivable	(6,885)	(3,876)
Prepaid expenses and other	(2,824)	14,603
Intangibles and other long-term assets	2	(1,684)
Regulatory assets	(3,188)	(5,055)
Accounts payable	114,815	(31,112)
Accounts payable to related companies	(22,308)	405
Customer advances and deposits	(34,803)	(55,370)
Exchanges payable	3,150	(584)
Accrued and other current liabilities	(18,869)	(41,543)
Other long-term liabilities	1,667	5,680
Income taxes payable	4,125	(1,278)
Price risk management liabilities, net	(23,832)	(53,079)
Net cash provided by operating activities	$ 383,944	$ 443,443

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

	Three Months Ended	
	March 31, 2008	February 28, 2007
NON-CASH FINANCING ACTIVITIES:		
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 2,693	$
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the period for interest, net of $10,471 and $5,741 capitalized for March 31, 2008 and February 28, 2007, respectively	$ 83,438	$ 61,216
Cash paid during the period for income taxes	$ (353)	$ 2,908
Transfer of investment in affiliate in purchase of Transwestern	$	$ 956,348

5. ACCOUNTS RECEIVABLE:

During the three months ended March 31, 2008, we exchanged a portion of our outstanding accounts receivable for Calpine Corporation (Calpine) common stock pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock was included as marketable securities which are classified as available-for-sale securities and are reflected as a current asset on the condensed consolidated balance sheet at March 31, 2008 at a fair value of $12.1 million.

Accounts receivable consisted of the following:

	March 31, 2008	December 31, 2007
Midstream and intrastate transportation and storage	$ 869,779	$ 612,533
Interstate transportation	23,064	31,676
Propane	175,920	183,516
Less allowance for doubtful accounts	(6,143)	(5,698)
Total, net	$ 1,062,620	$ 822,027

The activity in the allowance for doubtful accounts for the propane operations for the three months ended March 31, 2008 consisted of the following:

Balance, December 31, 2007	$ 5,698
Accounts receivable written off, net of recoveries	(759)
Provision for loss on accounts receivable	1,204
Balance, March 31, 2008	$ 6,143

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.

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Inventories consisted of the following:

	March 31, 2008	December 31, 2007
Natural gas, propane and other NGLs	$ 96,657	$ 342,457
Appliances, parts and fittings and other	19,503	19,497
Total inventories	$ 116,160	$ 361,954

7. INTANGIBLES AND OTHER LONG-TERM ASSETS:

Intangibles and other long-term assets are stated at cost net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. Components and useful lives of intangibles and other long-term assets were as follows:

	March 31, 2008		December 31, 2007	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (5 to 15 years)	$ 37,807	$ (20,673)	$ 34,855	$ (19,438)
Customer lists (3 to 15 years)	143,255	(30,032)	139,097	(26,821)
Contract rights (6 to 15 years)	23,015	(2,323)	23,015	(1,849)
Other (10 years)	2,677	(1,658)	2,677	(1,463)
Total amortizable intangible assets	206,754	(54,686)	199,644	(49,571)
Non-amortizable assets -Trademarks	72,148		70,339	
Total intangible assets	278,902	(54,686)	269,983	(49,571)
Other long-term assets:				
Financing costs (3 to 15 years)	53,304	(11,860)	42,432	(10,578)
Regulatory assets	77,533	(3,427)	73,687	(2,623)
Other	26,173		26,808	
Total intangibles and other long-term assets	$ 435,912	$ (69,973)	$ 412,910	$ (62,772)

Aggregate amortization expense of intangible assets is as follows:

	Three Months Ended	
	March 31, 2008	February 28, 2007
Reported in depreciation and amortization	$ 4,299	$ 4,082
Reported in interest expense	$ 1,282	$ 1,317

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

Years Ending December 31:	
2008 (remainder)	$ 19,130
2009	24,914
2010	23,322
2011	21,880
2012	19,819

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, in accordance with Statement of Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually at August 31, or more frequently if circumstances dictate, in accordance with SFAS 144. No impairment of intangible assets was required for the three months ended March 31, 2008 or February 28, 2007.

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8. 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 three-month periods ended March 31, 2008 and February 28, 2007, 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 basis 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.

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

	Three Months Ended	
	March 31, 2008	February 28, 2007
Current provision (benefit):		
Federal	$ (523)	$ 3,336
State	3,272	2,487
Total	2,749	5,823
Deferred provision (benefit):		
Federal	2,834	(2,247)
State	279	(276)
Total	3,113	(2,523)
Total tax provision	$ 5,862	$ 3,300
Effective tax rate	1.80%	1.00%

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

9. INCOME PER LIMITED PARTNER UNIT:

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

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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:

	Three Months Ended	
	March 31, 2008	**February 28, 2007**
Net income	$ 328,335	$ 311,114
Adjustments:		
General Partner s equity ownership	(6,567)	(6,222)
General Partner s incentive distributions	(67,797)	(54,345)
Limited Partners interest in net income	253,971	250,547
Additional earnings allocation to General Partner	(62,094)	(68,354)
Net income available to limited partners	$ 191,877	$ 182,193
Weighted average limited partner units basic	142,762,265	136,977,139
Basic net income per limited partner unit	$ 1.34	$ 1.33
Weighted average limited partner units	142,762,265	136,977,139
Dilutive effect of Unit Grants	435,535	320,567
Weighted average limited partner units, assuming dilutive effect of Unit Grants	143,197,800	137,297,706
Diluted net income per limited partner unit	$ 1.34	$ 1.33

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10. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	March 31, 2008	December 31, 2007	Maturities
ETP Senior Notes:			
2008 6.0% Senior Notes, net of discount of $661	$ 349,339	$	One payment of $350,000 due July 13, 2013. Interest is paid semi-annually.
2008 6.7% Senior Notes, net of discount of $1,764	598,236		One payment of $600,000 due July 2, 2018. Interest is paid semi-annually.
2008 7.5% Senior Notes, net of discount of $5,742	544,258		One payment of $550,000 due July 1, 2038. Interest is paid semi-annually.
2006 6.125% Senior Notes, net of discount of $316 and $322, respectively	399,684	399,678	One payment of $400,000 due February 15, 2017. Interest is paid semi-annually.
2006 6.625% Senior Notes, net of discount of $2,224 and $2,231, respectively	397,776	397,769	One payment of $400,000 due October 15, 2036. Interest is paid semi-annually.
2005 5.95% Senior Notes, net of discount of $1,684 and $1,733, respectively	748,316	748,267	One payment of $750,000 due February 1, 2015. Interest is paid semi-annually.
2005 5.65% Senior Notes, net of discount of $274 and $288, respectively	399,726	399,712	One payment of $400,000 due August 1, 2012. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Series Notes, including premium of $3,933 and $4,077, respectively	91,933	92,077	One payment of $88,000 due November 17, 2014. Interest is paid semi-annually.
5.54% Senior Unsecured Series Notes, net of discount of $4,724 and $4,855, respectively	120,276	120,145	One payment of $125,000 due November 17, 2016. Interest is paid semi-annually.
5.64% Senior Unsecured Series Notes	82,000	82,000	One payment due May 24, 2017. Interest is paid semi-annually.
5.89% Senior Unsecured Series Notes	150,000	150,000	One payment due May 24, 2022. Interest is paid semi-annually.
6.16% Senior Unsecured Series Notes	75,000	75,000	One payment due May 24, 2037. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
1996 8.55% Senior Secured Notes	48,000	48,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
1997 Medium Term Note Program:			
7.17% Series A Senior Secured Notes	4,800	4,800	Annual payments of $2,400 due each November 19 through 2009. Interest is paid semi-annually.
7.26% Series B Senior Secured Notes	10,000	10,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
2000 and 2001 Senior Secured Promissory Notes:			
8.55% Series B Senior Secured Notes	13,714	13,714	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	15,500	15,500	

Annual payments of $4,000 due August 15, 2008, and $

5,750 due each August 15, 2009 and 2010. Interest is paid quarterly.

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8.67% Series D Senior Secured Notes	58,000	58,000	Annual payments of $12,450 due August 15, 2008 and 2009, $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	7,000	7,000	Annual payments of $1,000 due each August 15, 2009 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.21% Series G Senior Secured Notes	3,800	3,800	Annual payments of $3,800 due each May 15 through 2008. Interest is paid quarterly.
7.89% Series H Senior Secured Notes	6,545	6,545	Annual payments of $727 due each May 15 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment of $16,000 due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility (including Swingline loan option)	492,000	1,626,948	Available through June 2012 see terms below under ETP Credit Facility .
HOLP Fourth Amended and Restated Senior Revolving Credit Facility		15,000	Available through June 30, 2011 - see terms below under HOLP Credit Facility .
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 7.81% and 5.51 % for March 31, 2008 and December 31, 2007, respectively	12,481	11,171	Due in installments through 2014.
Other	3,109	3,174	Due in installments through 2024.
	4,687,493	4,344,300	
Current maturities	(47,213)	(47,036)	
	$ 4,640,280	$ 4,297,264	

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

2008 remaining	$ 45,685
2009	45,103
2010	40,239
2011	33,972
2012	914,380
Thereafter	3,608,114
	$ 4,687,493

ETP Senior Notes

On March 28, 2008, we issued a total of $1.5 billion aggregate principal amount of Senior Notes comprised of $350.0 million of 6.00% Senior Notes due 2013, $600.0 million of 6.70% Senior Notes due 2018, and $550.0 million of 7.50% Senior Notes due 2038 (collectively, the ETP

2008 Senior Notes). We used the proceeds of approximately $1.48 billion (net of bond discounts of $8.2 million and other offering costs of $10.8 million) from the issuance of the ETP 2008 Senior Notes to repay borrowings and accrued interest outstanding under our $500.0 million, 364-day term loan credit facility and to repay a portion of amount outstanding under the ETP Credit Facility. Interest on the ETP 2008 Senior Notes is due semiannually. The Partnership may redeem some or all of the ETP 2008 Senior Notes at any time, or from time to time, pursuant to the terms of the indenture. The ETP 2008 Senior Notes have been registered under the Securities Act of 1933 (as amended) pursuant to our Registration Statement on Form S-3ASR, as supplemented by the Prospectus Supplement dated March 25, 2008, filed with the SEC on March 26, 2008.

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

ETP Credit Facility

We have available a $2.0 billion revolving credit facility (the ETP 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 March 31, 2008, there was a balance of $492.0 million in revolving credit loans (with no outstanding balance in swingline loans) and $61.5 million in letters of credit. The weighted average interest rate on the total amount outstanding at March 31, 2008, was 4.183%. The total amount available under the ETP Credit Facility, as of March 31, 2008, which is reduced by any amounts outstanding under the swingline loan and letters of credit, was $1.4 billion. 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 12, 2008, we borrowed the entire amount available under our $500.0 million, 364-day term loan credit facility (the 364-Day Credit Facility) 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 the Base Rate for a designated period. The indebtedness under the 364-Day Credit Facility is unsecured and is not guaranteed by us or any of our 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 contained covenants similar to the covenants of the ETP Credit Facility. On March 28, 2008 we used proceeds from our ETP 2008 Senior Notes offering (see above) to retire this debt.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the HOLP Credit Facility) is available to HOLP through June 30, 2011 which may be expanded to $150.0 million. The HOLP Credit Facility has a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on HOLP s Leverage Ratio, as defined in the HOLP Credit Facility credit agreement, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, sale of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Credit Facility. As of March 31, 2008, there was no balance outstanding on the revolving credit loans. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Credit Facility. There were outstanding letters of credit of $1.0 million at March 31, 2008. The sum

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of the loans made under the HOLP Credit Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Credit Facility. The amount available at March 31, 2008 was $74.0 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 March 31, 2008 the HOLP Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

11. PARTNERS CAPITAL AND UNIT-BASED COMPENSATION PLANS:

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 March 31, 2008, we had 142,819,957 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. 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 $0.7 million for the three months ended March 31, 2008 in connection with the unit issuance discussed below. There was a total required contribution of $5.8 million, including $0.1 million in accrued interest, from ETP GP which has not yet been paid and was therefore recorded as a reduction of partner capital.

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 three-month period ended March 31, 2008 is as follows:

	Number of Units
Balance, beginning of period	142,069,957
Common Units issued in connection with a public offering	750,000
Balance, end of period	142,819,957

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

Quarterly Distributions of Available Cash

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

On February 18, 2008 we paid a quarterly distribution (for the four-month transition period) of $90.9 million in the aggregate for ETP GP s 2% general partner interest in the Partnership and its Incentive Distribution Rights.

On April 24, 2008, we declared a per unit cash distribution of $0.86875, or $3.475 per Limited Partner Unit annually (a $0.10 increase from the previous distribution per Limited Partner Unit) for the quarter ended March 31, 2008, which will be paid on May 15, 2008 to Unitholders of record at the close of business on May 5, 2008.

The total amount of distributions declared (all from Available Cash from Operating Surplus) related to the three months ended March 31, 2008 was as follows:

Limited Partners -	
Common Units	$ 124,075
Class E Units	3,121
General Partners -	
2% Ownership	3,979
Incentive Distribution Rights	67,797
	$ 198,972

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 $8.1 million and $2.9 million for the three months ended March 31, 2008 and February 28, 2007, respectively.

2004 Unit Plan

Our Amended and Restated 2004 Unit 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 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 March 31, 2008, 412,559 ETP Common Units were available for future grants under the 2004 Unit Plan.

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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 was structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three year period. The performance criteria was generally based upon the total return (unit price appreciation plus cash distributions) to our Unitholders as compared to a group of publicly traded partnership peer companies. 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.

We assumed a weighted average risk-free interest rate of 3.63% for the three months ended March 31, 2008 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 March 31, 2008, the grant-date average per unit cash distributions were estimated to be $7.65. Upon vesting, ETP Common Units are issued.

The following table shows the activity of the employee grants during the three months ended March 31, 2008:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2007	1,039,529	$ 42.27
Awards granted	47,000	39.92
Awards forfeited	(25,808)	41.27
Unvested awards as of March 31, 2008	1,060,721	$ 42.19

The total expected compensation expense to be recognized related to the unvested employee awards as of March 31, 2008 is:

Years Ending December 31:	
2008 (remainder)	$ 16,131
2009	7,898
2010	3,920
2011	2,144
2012	902

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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 three months ended March 31, 2008 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 March 31, 2008, the grant-date average per unit cash distributions were estimated to be $6.15.

There were no new Director Grants, or awards vested during the three-months ended March 31, 2008. Unvested Director Grant awards as of December 31, 2007 and March 31, 2008 were as follows:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards	6,928	$ 40.47

The total expected compensation expense to be recognized related to the unvested Director Awards as of March 31, 2008 is:

Years Ending December 31:	
2008 (remainder)	$ 82
2009	41
2010	10

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 March 31, 2008, there have been no Long-Term Incentive Grants made under the Plan.

Related Party Awards

During 2007, a partnership (McReynolds Equity Partners, L.P.), the general partner of which is owned and controlled by the President of our General Partner, awarded to certain new officers of ETP certain rights related to units of Energy Transfer Equity, L.P. (ETE) previously issued by ETE to such officer. These rights include the economic benefits of ownership of these units based on a 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 and 60,000 unit awards vested in March 2008. Awards granted through March 31, 2008 result in a total non-cash compensation expense of approximately $23.5 million to be recognized over the related vesting period. For the three-month periods ended March 31, 2008 and February 28, 2007, we recognized non-cash compensation expense of $2.2 million and $0.4 million, respectively, 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 (remainder)	$4,743
2009	4,122
2010	2,399
2011	1,146
2012	175

12. <u>REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES</u>:

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 $710.0 million including an allowance for funds used during construction (AFUDC) with projected phased-in service dates in the third and fourth quarter of 2008. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity (Order). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. On December 17, 2007, two parties filed requests for rehearing of the Order and on December 20, 2007, one party filed a motion to stay the Order. On February 21, 2008, the FERC reaffirmed its decision in the Order; thus, Transwestern notified customers of the commencement of construction in January 2008. Transwestern has incurred expenditures of $442.0 million through March 31, 2008 for the Phoenix project.

On December 13, 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. (KMEP) 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 $1.3 billion pipeline project is expected to be in service by the first quarter of 2009. MEP has incurred expenditures of $100.2 million during the three months ended March 31, 2008 related to this project and $195.4 million since inception.

On February 29, 2008, MEP, our joint venture with KMEP, entered into a credit agreement that provides for a $1.4 billion senior revolving credit facility (the MEP Facility). We have guaranteed 50% of the obligations of MEP under the MEP Facility, with the remaining 50% of MEP Facility obligations guaranteed by KMEP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is available through February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our debt rating and that of KMEP, with a maximum fee of 0.15%. The MEP Facility also has a swingline loan option with a maximum borrowing of $25.0 million at a prime rate. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit available under the MEP Facility. The indebtedness under the MEP Facility is prepayable at any time at the option of MEP without penalty. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets. As of March 31, 2008, MEP had $210.0 million outstanding borrowings under the MEP Facility. The weighted average interest rate on the total amount outstanding as of March 31, 2008 was 3.488%. The total amount available under the MEP Facility was $1.19 billion as of March 31, 2008.

In March 2008, MEP reimbursed ETP a net $63.5 million from the MEP facility for previous advances ETP made to MEP.

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 $8.2 million and $5.8 million for the three-month periods ended March 31, 2008 and February 28, 2007, respectively, and has been included in operating expenses in the accompanying condensed 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

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Houston Ship Channel. The FERC has alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the Natural Gas Act (NGA). We allegedly violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. Our Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to the FERC-approved rates, terms and conditions of service. The allegations related to the Oasis pipeline include claims that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at 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.

In its Order and Notice, the FERC is seeking $70.1 million in disgorgement of profits, plus interest, and $97.5 million in civil penalties relating to these matters. The FERC has taken the position that, once it receives our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. On August 27, 2007, ETP filed a request for rehearing of the Order and Notice. On December 20, 2007, the FERC issued an order denying rehearing and directed FERC Staff to file a brief recommending disposition of issues by order or by evidentiary hearing. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC s claims and requested a dismissal of the FERC proceeding. On February 14, 2008, the Enforcement Staff of the FERC filed a brief recommending that the FERC refer various matters relating to its market manipulation allegations for an evidentiary hearing before a FERC administrative law judge. The Enforcement Staff also recommended that FERC issue an order assessing the $15.5 million portion of the above-referenced penalty against ETP with respect to the allegations related to ETP s Oasis Pipeline and that the Oasis-related penalty assessment, if not paid, then be referred by the FERC to a federal district court for *de novo* review. The Enforcement Staff also recommended that the FERC impose certain changes in Oasis business operations and refunds to certain Oasis customers as previously proposed in the Order and Notice. Finally, the Enforcement Staff recommended that the FERC pursue market manipulation claims related to ETP s trading activities in October 2005, for November 2005 monthly deliveries, a period not previously covered by FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month. If the claims related to this additional month are pursued by the FERC, the total amount of civil penalties and disgorgement of profits sought by the FERC would be approximately $200.0 million. On March 31, 2008, we responded to the Enforcement Staff s brief. The FERC has not taken any substantive action related to these recommendations of the Enforcement Staff.

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

On July 26, 2007, the United States Commodity Futures Trading Commission (the CFTC) filed suit in United States District Court for the Northern District of Texas alleging that we violated provisions of the Commodity Exchange Act by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, ETP entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, ETP agreed to pay the CFTC $10.0 million and the CFTC agreed to release ETP and its affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that ETP is permanently enjoined from attempting to manipulate the price of any commodity in interstate commerce in violation of the Commodity Exchange Act. By consenting to the entry of the Consent Order, ETP neither admitted nor denied the allegations made by the CFTC in this proceeding. The settlement reduced our existing accrual and was paid from cash flow from operations on March 19, 2008.

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In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE for damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETE for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETE contains an additional allegation that the defendants transported gas in a manner that favored their affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producers/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We have filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable. The claimants have agreed to a four-week stay of the arbitration through May 22, 2008 while they evaluate the state court pleading.

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. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The 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. The plaintiffs have requested certification of their suit as a class action, and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008 we filed a motion to dismiss the complaint.

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

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 accrual related to these matters. In accordance with applicable accounting standards, we will review the amount of our existing 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. Appellee Transwestern filed its separate response brief on January 11, 2008 and Grynberg s reply brief is due June 16, 2008 and it is anticipated that the hearing on all briefs will be in September 2008.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies and American Electric Power Corporation (AEP), were engaged in ongoing litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel Storage Facility (Cushion Gas). This litigation is referred to as the Cushion Gas Litigation . Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.0 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel Storage Facility. AEP filed a notice of motion for reconsideration questioning the court s damages calculation. AEP will determine whether it will appeal the court decision once a final judgment is entered. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP does not expect that it will be liable for any portion of this court award.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of March 31, 2008 and December 31, 2007, an accrual of $20.4 million and $30.5 million, 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 $11.0 million. Transwestern received FERC approval for rate recovery of the portion of soil and groundwater remediation not related to PCBs effective April 1, 2007.

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

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

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amount has been recorded in our March 31, 2008 or our December 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 March 31, 2008 and December 31, 2007, an accrual on an undiscounted basis of $15.2 million and $15.7 million 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 March 31, 2008, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2010. Through March 31, 2008, a total of $1.5 million of capital costs and $3.6 million of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. Through March 31, 2008, no capital costs or operating and maintenance costs have been incurred for pipeline integrity costs for Transwestern. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

13. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

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.

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

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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 $60.5 million and $42.2 million as of March 31, 2008 and December 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 $22.6 million and $122.7 million for the three months ended March 31, 2008 and February 28, 2007, respectively, related to commodity financial instruments that were previously reported in OCI.

We expect losses of $4.1 million related to commodity derivatives 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.

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The following table details the outstanding commodity-related derivatives and their fair values as of March 31, 2008 and December 31, 2007, respectively:

March 31, 2008

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	18,287,500	2008-2010	$ 2,729
Swing Swaps IFERC	Gas	(16,690,000)	2008-2009	2,095
Fixed Swaps/Futures	Gas	(22,070,000)	2008-2009	(14,763)
Forward Physical Contracts	Gas	(124,935)	2008	1,313
Options	Gas	(490,000)	2008	(14)
Forwards/Swaps in Gallons	Propane	2,310,000	2008-2009	658
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	25,865,000	2008-2009	$ 3,404
Swing Swaps IFERC	Gas	(17,300,000)	2008	(7,882)
Forward Physical Contracts	Gas		2008	918
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	825,000	2008-2009	$ (76)
Fixed Swaps/Futures	Gas	(182,500)	2008-2009	(1,654)

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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The following table summarizes the fair value of our financial assets and liabilities as of March 31, 2008 based on inputs used to derive their fair values in accordance with SFAS 157 (see Note 3 for further detail):

		Fair Value Measurements at Reporting Date Using	
Description	Fair Market Value Total	Quoted prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets			
Marketable Securities	$ 13,651	$ 13,651	$
Commodity Derivatives	13,010	1,511	11,499
Liabilities			
Commodity Derivatives	(26,281)	(21,782)	(4,499)
Interest Rate Derivatives	(3,311)		(3,311)
	$ (2,931)	$ (6,620)	$ 3,689

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 three months ended February 28, 2007, the Partnership discontinued application of hedge accounting in connection with certain derivative financial instruments that were qualified and designated as cash flow hedges related to forecasted sales of natural gas stored in 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 February through March 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 three months ended February 28, 2007, the Partnership recognized previously deferred unrealized gains of $17.8 million from the discontinued application of hedge accounting, which is included in the reclassification into earnings from OCI. The Partnership classified the unrealized gains as costs of products sold in its consolidated statement of operations. We did not discontinue the application of hedge accounting on any positions during the three months ended March 31, 2008.

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 three-month period ending March 31, 2008. For the three-month period ended February 28, 2007, gains or losses related to our interest rate derivatives were reported in interest expense.

The following table represents interest rate swap derivatives and their fair values as of March 31, 2008 and December 31, 2007:

				Fair Value Liability as of	
Term	**Notional Amount**	**Type**	**SFAS 133 Hedge**	**March 31, 2008**	**December 31, 2007**
March 2009	$ 125,000	Pay Fixed 5.14% Receive Float	No	$ 3,311	$ 1,530

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We reclassified into earnings gains of $0.3 million and gains of $2.7 million for the three months ended March 31, 2008 and February 28, 2007, respectively, related to interest rate swaps that were previously reported in OCI. We expect gains of $0.4 million 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 March 31, 2008 and December 31, 2007:

Date Settled	Term	Notional Amount	Type	Other Comprehensive Income (Loss) as of March 31, 2008	December 31, 2007
April 2007	2014	$ 400,000	LIBOR Forward Starting	$ (11,135)	$ (11,135)
June 2006	2016	200,000	Treasury Lock	11,916	12,210
January 2005	2017	100,000	Treasury Lock	(260)	(269)
				$ 521	$ 806

Summary of Derivative Gains and Losses

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

	Three Months Ended March 31, 2008	February 28, 2007
Commodity-related		
Unrealized non-trading gains (losses) recognized in cost of products sold related to commodity-related derivative activity, excluding ineffectiveness	$ (20,024)	$ 30,146
Ineffective portion of derivatives qualifying for hedge accounting recognized in cost of products sold	(8,320)	(1,103)
Realized non-trading gains related to commodity-related derivatives included in cost of products sold	4,946	98,279
Trading unrealized losses recognized in revenues	(5,859)	(6,329)
Trading realized gains recognized in revenues	6,270	4,610
Interest rate swaps		
Unrealized gains (losses) on interest rate swap included in other income (March 2008) and interest expense (February 2007), excluding ineffectiveness	$ (1,781)	$ 339
Ineffective portion of derivatives qualifying for hedge accounting included in interest expense		2,390
Realized gains on interest rate swap included in interest expense and other income, net, in 2008, and interest expense in prior periods	1,467	345

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.

14. RELATED PARTY TRANSACTIONS:

During the three months ended March 31, 2008, we made the following sales to and purchases from affiliates of Enterprise G.P. Holdings, L.P. (Enterprise):

Enterprise Transactions	Product	Volumes (in thousands)	Dollars
Propane Operations -			
Purchases	Propane gallons	138,812	$ 196,092
Natural Gas Operations -			
Sales	NGLs gallons	7,386	$ 10,159
	Natural Gas MMBtu	1,602	12,861
	Fees		1,672
Purchases	Natural Gas Imbalances MMBtu	(794)	$ (4,688)
	Natural Gas MMBtu	(2,409)	19,772
	Fees		255

Accounts receivable from and accounts payable to related companies as of March 31, 2008 and December 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. Our propane operations routinely buy and sell product with Enterprise. The following table summarizes the related party balances with Enterprise on our condensed consolidated balance sheets:

	March 31, 2008	December 31, 2007
Natural Gas Operations:		
Accounts receivable	$ 11,138	$ 9,770
Accounts payable	9,228	6,840
Imbalance payable	1,530	6,218
Propane Operations:		
Accounts receivable	$ 4,651	$ 3,396
Accounts payable	15,064	41,939

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

	March 31, 2008	December 31, 2007
ETP GP	$ 133	$ 5,113
McReynold s Equity Partners, L.P.	220	
ETE	2,372	1,553
MEP	12,868	743
Energy Transfer Technologies, Ltd.	89	922
Others	1,020	2,941

Total accounts receivable from related companies excluding Enterprise	$ 16,702	$ 11,272

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Effective October 19, 2007, the Chief Executive Officer (CEO) of our General Partner, Mr. Kelcy Warren, voluntarily determined that his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. In accordance with GAAP, we recorded compensation expense and an offsetting capital contribution of $0.3 million ($0.1 million in salary and $0.2 million in accrued bonuses) for the three months ended March 31, 2008 as an estimate of the reasonable compensation level for the CEO position.

15. 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

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

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

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general, administrative expenses, gain (loss) on disposal of assets, minority interests, interest expense, earnings (losses) from equity investments and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. We allocate administration expenses from the Partnership to our Operating Partnerships using the Modified Massachusetts Formula Calculation (MMFC) which is based on factors such as respective segments gross margins, employee costs, and property and equipment. The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month. The amounts allocated for the three months ended March 31, 2008 and February 28, 2007, were approximately $3.9 million and $3.9 million to the midstream and intrastate transportation segments, $1.2 million and $1.5 million to the interstate transportation segment, and $2.5 million and $3.4 million to the propane segment, for a total of approximately $7.6 million and $8.8 million, respectively. 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 for the three months ended March 31, 2008 and February 28, 2007 were $1.4 million and $2.2 million from the midstream and intrastate transportation segments, and $0.6 million and $0.9 million from the propane segments, respectively. No such amounts were allocated to the Partnership from the interstate transportation segment for the three months ended March 31, 2008 or February 28, 2007.

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

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007
Volumes:		
Midstream		
Natural gas MMBtu/d sold	1,236,396	819,611
NGLs Bbls/d sold	27,794	15,901
Transportation and storage		
Natural gas MMBtu/d transported	9,521,181	5,030,631
Natural gas MMBtu/d sold	1,696,912	1,655,278
Interstate transportation		
Natural gas MMBtu/d transported	1,619,358	1,728,056
Retail propane gallons (in thousands)	234,414	253,715

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007
Revenues:		
Midstream	$ 1,245,763	$ 624,245
Eliminations	(774,174)	(297,620)
Intrastate transportation and storage	1,480,842	1,108,055
Interstate transportation	55,416	58,158
Retail propane and other retail propane related	625,715	529,555
All other	5,809	40,087
Total revenues	$ 2,639,371	$ 2,062,480
Cost of Sales:		
Midstream	$ 1,150,969	$ 573,712
Eliminations	(774,174)	(297,620)
Intrastate transportation and storage	1,200,473	862,617
Retail propane and other retail propane related	397,730	311,364
All other	4,720	35,743
Total cost of sales	$ 1,979,718	$ 1,485,816
Depreciation and Amortization:		
Midstream	$ 13,846	$ 5,565
Intrastate transportation and storage	16,452	12,013
Interstate transportation	9,300	9,654
Retail propane and other retail propane related	19,086	17,937
All other	144	191
Total depreciation and amortization	$ 58,828	$ 45,360

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007
Operating Income (Loss):		
Midstream	$ 52,386	$ 25,048
Intrastate transportation and storage	187,848	182,815
Interstate transportation	29,226	34,112
Retail propane and other retail propane related	106,955	114,314
All other	(5)	1,666
Selling general and administrative expenses not allocated to segments	(2,924)	407
Total operating income	$ 373,486	$ 358,362
Other items not allocated by segment:		
Interest expense	$ (55,549)	$ (40,772)
Equity in earnings (losses) of affiliates	74	(514)
Loss on disposal of assets	(1,451)	(3,229)
Other income, net	17,637	1,423
Income tax expense	(5,862)	(3,300)
Minority interests		(856)
	(45,151)	(47,248)
Net income	$ 328,335	$ 311,114

	March 31, 2008	December 31, 2007
Total Assets:		
Midstream	$ 1,572,525	$ 1,304,187
Intrastate transportation and storage	4,033,550	3,976,895
Interstate transportation	1,956,291	1,834,941
Retail propane and other retail propane related	1,813,427	1,778,426
All other	147,291	113,712
Total	$ 9,523,084	$ 9,008,161

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007
Additions to Property, Plant and Equipment including acquisitions (accrual basis):		
Midstream	$ 70,293	$ 53,522
Intrastate transportation and storage	158,464	256,896
Interstate transportation	202,357	1,269,051
Retail propane and other retail propane related	48,410	18,921
All other	485	367
Total	$ 480,009	$ 1,598,757

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

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for our previous fiscal year ended August 31, 2007 filed with the Securities and Exchange Commission (SEC) on October 30, 2007. Our

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Management s Discussion and Analysis includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Item 1A Risk Factors included in this report and in our Annual Report for the fiscal year ended August 31, 2007.

Overview

General

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

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

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

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

We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional cash flow to our Unitholders for years to come. Recently, we announced the completion of our Southeast Bossier Pipeline and the construction of the Texas Independence Pipeline to be completed in the third quarter of 2009.

Our principal operations are conducted in the following reportable segments (see Note 15 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.

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.

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

We evaluate segment performance based on operating income (either in total or by individual segment) which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for our previous fiscal year ended August 31, 2007 filed with the SEC on October 30, 2007.

Analytical Analysis

In November 2007, we filed a Form 8-K indicating that our Limited Partnership Agreement had been amended to change our fiscal year end to the calendar year. Thus, our new year began on January 1, 2008. We completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the three-month period ended March 31, 2008 and the three-month period ended February 28, 2007 (the first three-month period of the previous fiscal year most nearly comparable to the three-month period ended March 31, 2008).

We did not recast the financial data for the prior fiscal period because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Furthermore, we believe the information and data of the three-month period ended February 28, 2007 is comparable to what would have been reported for the three-month period ended March 31, 2007 if we had recast the prior period information. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the three-month period ended February 28, 2007 to the period ended March 31, 2008 are substantially similar to what would have been reflected had we recast the information for the period ended March 31, 2007.

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

Analysis of Operating Data Volumes

Midstream

	Three Months Ended		
	March 31, 2008	February 28, 2007	Increase
Natural gas MMBtu/d sold	1,236,396	819,611	416,785
NGLs Bbls/d sold	27,794	15,901	11,893

For the three months ended March 31, 2008 compared to the three months ended February 28, 2007, natural gas sales volumes increased principally due to more favorable market conditions during the three months ended March 31, 2008 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 plant in October 2007 and the continued expansion of the plant since placing it into service.

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Intrastate Transportation and Storage

	Three Months Ended March 31, 2008	February 28, 2007	Increase
Natural gas MMBtu/d transported	9,521,181	5,030,631	4,490,550
Natural gas MMBtu/d sold	1,696,912	1,655,278	41,634

For the three months ended March 31, 2008 compared to the three months ended February 28, 2007, transported natural gas volumes increased principally due to the increased volumes experienced on our ET Fuel and East Texas Pipeline systems as a result of increased demand to transport natural gas out of the Barnett Share and Bossier Sands producing regions, and the completion of the Cleburne to Carthage pipeline in April of 2007. The increase was also attributed to higher transportation volumes on our Oasis pipeline as a result of favorable market conditions between the Waha and Katy/Houston Ship Channel market hubs. Natural gas sales volumes on the HPL System for the three months ended March 31, 2008 compared to the three months ended February 28, 2007, were relatively flat.

Interstate Transportation

	Three Months Ended March 31, 2008	February 28, 2007	Decrease
Natural gas MMBtu/d transported	1,619,358	1,728,056	(108,698)

The decrease was principally due to unfavorable pricing at the San Juan and Permian market hubs resulting in lower transportation volumes on the eastern portion of our pipeline offset by increased demand from our western markets.

Retail Propane

	Three Months Ended March 31, 2008	February 28, 2007	Decrease
Retail propane gallons sold (in thousands)	234,414	253,715	(19,301)

Total gallons sold by our retail propane operations decreased due to customer conservation and the slow down of new home construction in our propane markets.

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Analysis of Results of Operations

Consolidated Results

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007	Change
Revenues	$ 2,639,371	$ 2,062,480	$ 576,891
Cost of sales	1,979,718	1,485,816	493,902
Gross margin	659,653	576,664	82,989
Operating expenses	178,970	133,809	45,161
Selling, general and administrative	48,369	39,133	9,236
Depreciation and amortization	58,828	45,360	13,468
Operating income	373,486	358,362	15,124
Interest expense	(55,549)	(40,772)	(14,777)
Equity in earnings (losses) of affiliates	74	(514)	588
Loss on disposal of assets	(1,451)	(3,229)	1,778
Other income, net	17,637	1,423	16,214
Income tax expense	(5,862)	(3,300)	(2,562)
Minority interests		(856)	856
Net income	$ 328,335	$ 311,114	$ 17,221

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

Interest Expense. Interest expense increased principally due to a net $9.8 million increase related to higher levels of borrowings on the Partnership s Senior Notes and the revolving credit facility and $2.9 million due to borrowings related to our interstate operations. Partnership borrowings increased primarily due to the financing of our growth capital expenditures and the Canyon acquisition. Interest expense also increased due to $2.7 million of unrealized gains related to non-hedged interest rate swaps and the ineffective portion of derivatives qualifying for hedge accounting included in interest expense for the three months ended February 28, 2007. Unrealized gains and losses related to non-hedged interest rate swaps were included in other income, net for the three months ended March 31, 2008. The increase in interest expense was offset by propane related interest which decreased $0.9 million due primarily to the scheduled debt payments that have occurred between the comparable periods.

Other Income, net. The increase is principally due to AFUDC on equity of $9.8 million and the excess of CIAC related to the $40.0 million reimbursement by Trunkline Gas Company, LLC in connection with an extension on our Southeast Bossier pipeline (see Note 3 to our condensed consolidated financial statements).

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 an increase in pretax book income of approximately $4.8 million earned by our corporate subsidiaries and the impact of having a full three months of activity being subject to the new Texas margin tax for the three months ending March 31, 2008 versus only two months of activity being subject to the new Texas margin tax for the three months ending February 28, 2007.

Segment Operating Results

Operating income by segment is as follows:

	Three Months Ended		
	March 31, 2008	February 28, 2007	Change
Midstream	$ 52,386	$ 25,048	$ 27,338
Intrastate Transportation and Storage	187,848	182,815	5,033
Interstate Transportation	29,226	34,112	(4,886)
Retail Propane	106,955	114,314	(7,359)
Other	(5)	1,666	(1,671)
Unallocated selling, general and administrative expenses	(2,924)	407	(3,331)
Operating income	$ 373,486	$ 358,362	$ 15,124

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

Unallocated Selling, General and Administrative Expenses. Selling, general and administrative expenses are 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 which results in over or under allocation of these costs due to timing differences.

Midstream

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007	Change
Revenues	$ 1,245,763	$ 624,245	$ 621,518
Cost of sales	1,150,969	573,712	577,257
Gross margin	94,794	50,533	44,261
Operating expenses	16,878	8,906	7,972
Selling, general and administrative	11,684	11,014	670
Depreciation and amortization	13,846	5,565	8,281
Segment operating income	$ 52,386	$ 25,048	$ 27,338

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

Increases in fee-based revenue of $33.6 million and processing margin of $1.0 million from our gathering and processing assets. The increase was due to incremental volumes from the completion of our Godley plant in October 2006 and the continued expansion of the plant since placing it into service. In addition, our midstream assets benefited from favorable market conditions to process and extract NGLs during the three months ended March 31, 2008 as compared to the three months ended February 28, 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 converted 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; and,

Canyon Gathering System. The acquisition of the Canyon Gathering System in October 2007 contributed approximately $7.9 million of incremental margin for the three months ended March 31, 2008.

Operating Expenses. Midstream operating expenses increased principally due to increased employee-related costs such as salaries, incentive compensation and healthcare costs of $2.1 million, increased plant operating expenses of $2.0 million, increased compressor rental expense of $1.8 million, increased chemical expenses of $1.0 million, increased compressor and pipeline maintenance of $0.2 million, increased vehicles expense of $0.3 million, and an increase of $0.6 million, in the aggregate, of other expenses. These increases were primarily due to the expansion of the Godley plant and the acquisition of the Canyon Gathering System in October 2007.

Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses increased principally due to increased employee-related costs such as salaries, incentive compensation and healthcare costs of

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$1.5 million, an increase in office expenses of $0.3 million, a $0.3 million increase due to less costs capitalized to construction projects, and an increase in other general and administrative expenses of $1.9 million offset by a decrease in allocated administrative overhead expenses of $1.4 million. The allocation of departmental costs between the midstream and the intrastate transportation and storage segments is based on factors such as respective gross margins, employee costs, and property and equipment and is intended to fairly present the segment s operating results. The increase was offset by a decrease of $1.9 million in legal costs. Effective January 1, 2008 we allocate legal costs associated with the regulatory matters equally between the midstream and transportation and storage segments. During the three months ended February 28, 2007, all legal costs related to the regulatory matter were recorded in the midstream segment.

Depreciation and Amortization. Midstream depreciation and amortization expense increased principally due to $5.6 million incremental depreciation on Canyon assets and continued expansion of our Godley plant since placing it into service in October 2006.

Intrastate Transportation and Storage

	Three Months Ended		
	March 31, 2008	February 28, 2007	Change
Revenues	$ 1,480,842	$ 1,108,055	$ 372,787
Cost of sales	1,200,473	862,617	337,856
Gross margin	280,369	245,438	34,931
Operating expenses	58,615	37,341	21,274
Selling, general and administrative	17,454	13,269	4,185
Depreciation and amortization	16,452	12,013	4,439
Segment operating income	$ 187,848	$ 182,815	$ 5,033

Gross Margin. Intrastate transportation and storage gross margin increased principally due to the following factors:

Volumes. Overall volumes on our transportation pipelines were higher compared to the same period last year due to increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, continued efforts to secure long-term shipper contracts, the completion of the Clebourne to Carthage pipeline during the 2007 fiscal year. The increase in transport volumes were also due to favorable market conditions between the Waha and Katy/Houston Ship Channel market hubs resulting in higher volumes on our Oasis pipeline. Transportation fees increased approximately $58.3 million for the three months ended March 31, 2008 as compared to the three months ended February 28, 2007. Retention revenue increased approximately $19.0 million due to increased volumes transported through our transportation pipelines;

Higher natural gas prices. Excluding the impact of volumetric changes, our fuel retention fees are directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees and decreases in natural gas prices tend to decrease our fuel retention fees. Our average natural gas prices for retained fuel increased from a range of $5.00 to $6.00/MMBtu during the three months ended February 28, 2007 to $8.00 to $9.00/MMBtu during the three months ended March 31, 2008 resulting in additional retention margin of $8.2 million;

Increases in processing margin of $6.1 million from our HPL System due to favorable market conditions to process and extract NGLs during the three months ended March 31, 2008; and, Net decrease in storage margins of $49.4 million. During the three months ended February 28, 2007, we recognized approximately $90.8 million in margin from sales of approximately 41 Bcf of natural gas from our Bammel storage facility. Market conditions during the three months ended March 31, 2008 resulted in sales of 36 Bcf of natural gas for margins of $52.8 million. In addition, during the three months ended February 28, 2007, we recognized approximately $18.0 million from the discontinuation of hedge accounting resulting from our determination that originally forecasted sales of natural gas from our Bammel storage facility were no longer probable to occur by the specified time period, or within an additional two-month time period thereafter. The decrease was offset by increased fee-based storage margins of $6.6 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;

Lower margins on gas sold on our HPL System of $7.3 million. Natural gas sales margins on the HPL System decreased principally 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. As such, we now account for these activities as natural gas transported rather than natural gas sold.

Operating Expenses. Intrastate transportation and storage operating expenses increased primarily due to increased fuel consumption of $19.1 million, increased employee costs of $2.5 million, increased ad-valorem tax of $0.8 million, and increased vehicle expense of $0.3 million. The increase in fuel consumption is due to increased transport volumes and increased natural gas prices. In addition, we now own much of our own compression which was previously contracted with third parties. This has led to increases of $1.2 million in compressor maintenance and $1.0 million in utilities. These increases were offset by a $3.0 million decrease in compressor rentals and a $1.5 million decrease in measurement expense and professional fees related to the EMS USA Inc. contract buyout in September 2007.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased principally due to $2.4 million of legal fees related to the regulatory matter and an increase in certain departmental costs allocated from the midstream segment of $2.1 million offset by decreased employee-related costs such as salaries, incentive compensation and healthcare costs of $0.3 million. As noted above, we began allocating legal fees associated with regulatory matters equally between the midstream and transportation and storage segments effective January 1, 2008. During the three months ended February 28, 2007, all legal costs related to the regulatory matter were recorded in the midstream segment.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased principally due to the continuing expansion of our pipeline system, most notably the Cleburne to Carthage Pipeline in April of 2007.

Interstate Transportation

	Three Months Ended		
	March 31, 2008	February 28, 2007	Change
Revenues	$ 55,416	$ 58,158	$ (2,742)
Operating expenses	11,220	8,521	2,699
Selling, general and administrative	5,670	5,871	(201)
Depreciation and amortization	9,300	9,654	(354)
Segment operating income	$ 29,226	$ 34,112	$ (4,886)

Revenues. Revenues decreased principally due to lower retained volumes from customers as a result of the implementation of the April 1, 2007 rate case offset slightly by higher natural gas prices.

Operating Expenses. Operating expenses increased due to $2.7 million of gas imbalances, $0.8 million due to reduction in linepack deliveries and $0.3 million for other expenses. The increases were offset by a decrease in ad valorem taxes of $1.1 million.

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Retail Propane

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007	Change
Retail propane revenues	$ 598,138	$ 499,252	$ 98,886
Other retail propane related revenues	27,577	30,303	(2,726)
Retail propane cost of sales	392,555	304,634	87,921
Other retail propane related cost of sales	5,175	6,730	(1,555)
Gross margin	227,985	218,191	9,794
Operating expenses	91,307	77,346	13,961
Selling, general and administrative	10,637	8,594	2,043
Depreciation and amortization	19,086	17,937	1,149
Segment operating income	$ 106,955	$ 114,314	$ (7,359)

Revenues. Retail propane revenues increased mainly due to increased sale prices driven by the increased cost of fuel. Historically, as the weather becomes colder, the gallon sales and revenues would typically increase. Although for the three months ended March 31, 2008 the weather was colder than normal and also colder than the three months ended February 28, 2007, this trend did not prevail during this period as customer conservation, the slow down in new home construction and the record fuel prices suppressed sales.

Costs of Sales. Retail propane cost of sales increased significantly due to the record fuel prices that we are experiencing through the period. Our overall cost of fuel, offset by the decrease in gallons sold, was the major factor in the increase in cost of sales. On average, fuel costs were approximately 29%, or $.47/gallon, higher during the three months ended March 31, 2008 as compared to the three months ended February 28, 2007.

Gross Margin. Overall gross margins increased even though gallon sales decreased and the margins were significantly influenced by the cost of product.

Operating Expenses. Operating expenses increased due 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 volume shortfalls.

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

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 February 28, 2007.

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 three months ended March 31, 2008 and February 28, 2007, our non-qualifying income was not expected to, or did not, exceed the statutory limit.

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

	Three Months Ended March 31, 2008	Three Months Ended February 28, 2007
Current provision (benefit):		
Federal	$ (523)	$ 3,336
State	3,272	2,487
Total	2,749	5,823
Deferred provision (benefit):		
Federal	2,834	(2,247)
State	279	(276)
Total	3,113	(2,523)
Total tax provision	$ 5,862	$ 3,300
Effective tax rate	1.80%	1.00%

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.

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 $52.3 million during the remainder of the 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 $25.0 million during the remainder of the 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 $907.0 million during the remainder of the year. We also expect to spend approximately $695.2 million in our interstate segment for constructing new pipelines and pipeline expansion, including $397.4 million related to our share of the MEP project which will be financed under MEP s credit facility, and approximately $18.0 million for customer propane tanks during the remainder of the 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 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.

On February 29, 2008, MEP, our joint venture with KMEP, entered into a credit agreement that provides for a $1.4 billion senior revolving credit facility (the MEP Facility). We have guaranteed 50% of the obligations of MEP under the MEP Facility, with the remaining 50% of MEP Facility obligations guaranteed by KMEP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is available through February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our debt rating and that of KMEP, with a maximum fee of 0.15%. The MEP Facility also has a swingline loan option with a maximum borrowing of $25.0 million at a prime rate. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit available under the MEP Facility. The indebtedness under the MEP Facility is prepayable at any time at the option of MEP without penalty. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets. As of March 31, 2008, MEP had $210.0 million outstanding borrowings under the MEP Facility. The weighted average interest rate on the total amount outstanding as of March 31, 2008 was 3.488%. The total amount available under the MEP Facility was $1.19 billion as of March 31, 2008. MEP incurred $100.2 million in expenditures related to this project during the three months ended March 31, 2008 and $195.4 million since inception.

In March 2008, MEP reimbursed ETP a net $63.5 million from the MEP facility for previous advances ETP made to MEP.

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 three months ended March 31, 2008, was $383.9 million as compared to cash provided by operating activities of $443.4 million for the three months ended February 28, 2007. The net cash provided by operations for the three months ended March 31, 2008 consisted of net income of $328.3 million, non-cash charges of $75.5 million, principally depreciation and amortization, unit-based compensation expense, and deferred income taxes and a decrease in cash from changes in operating assets and liabilities of $19.9 million. Various components of operating assets and liabilities changed significantly from the prior period including factors such as the change in accrued and other current liabilities due to a $10.0 million settlement in the CFTC suit, 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 three months ended March 31, 2008 of $419.4 million was comprised primarily of cash paid for acquisitions of $40.8 million and $466.0 million invested for growth capital expenditures (net of contribution in aid of construction costs as discussed in Note 3 to our condensed consolidated financial statements), including changes in accruals of $39.4 million. Total growth capital expenditures consists of $268.2 million for our intrastate operations, $186.1 million for our interstate operations, and $11.7 million for our propane operations. We also incurred $26.0 million in maintenance expenditures needed to sustain operations of which $13.4 million related to intrastate operations, $2.7 million related to interstate operations, and $9.9 million to propane operations. The above expenditures were offset by a $63.5 million net reimbursement from MEP to the Partnership for previous advances to MEP.

Financing Activities. Cash provided by financing activities was $101.3 million for the three months ended March 31, 2008. We received $35.0 million in net proceeds from an equity offering (see Note 11 to our condensed consolidated financial statements). Proceeds from the equity offering were used to repay the ETP Credit Facility. We also received net proceeds of $1.48 billion from the issuance of new ETP Senior Notes (see Note 10 to our condensed consolidated financial statements) which were used to repay principal and interest on the $500.0 million ETP 364-Day Credit Facility and to repay a portion of the debt outstanding on the ETP Credit Facility. We had a net increase in our debt level of $336.9 million primarily due to the issuance of the ETP Senior Notes to repay the ETP 364-Day Credit Facility, to fund our growth capital expenditures and for general partnership purposes. During the three months ended March 31, 2008, we paid distributions of $251.6 million to our partners related to the four-month period ended December 31, 2007.

Financing and Sources of Liquidity

On January 8, 2008 we issued 750,000 common units at $48.81 per common unit to underwriters pursuant to the exercise of a 30-day option to purchase common units to cover over-allotments in connection with a public offering of 5,000,000 of our common units representing limited partner interests. The proceeds of $35.0 million, net of offering costs, were used to repay borrowings from the ETP Credit Facility.

On March 26, 2008, we issued a total of $1.5 billion aggregate principal amount of ETP 2008 Senior Notes. The net proceeds of $1.48 billion were used to fully repay the ETP 364-Day Credit Facility, to repay a portion of the amount outstanding on the ETP Credit Facility and for general partnership purposes.

During 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.

Description of Indebtedness

Our indebtedness as of March 31, 2008 consists of $350.0 million in principal amount of 6.00% Senior Notes due 2013, $600.0 million in principal amount of 6.70% Senior Notes due 2018, $550.0 million in principal amount of 7.50% Senior Notes due 2038, $750.0 million in principal amount of 5.95% Senior Notes due 2015, $400.0 million in principal amount of 5.65% Senior Notes due 2012, $400.0 million in principal amount of 6.125% Senior Notes due 2017 and $400.0 million in principal amount of 6.625% Senior Notes due 2036 (collectively, the ETP Senior Notes), and a revolving credit facility that allows for borrowings of up to $2.0 billion (expandable to $3.0 billion) available through June 20, 2012 (the ETP Credit Facility). We also currently 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 Report on Form 8-K as of December 31, 2007, and for the four-month transition period then ended, filed with the Securities and Exchange Commission on March 19, 2008.

ETP Senior Notes

On March 28, 2008, we issued a total of $1.5 billion aggregate principal amount of Senior Notes comprised of $350.0 million of 6.00% Senior Notes due 2013, $600.0 million of 6.70% Senior Notes due 2018, and $550.0 million of 7.50% Senior Notes due 2038 (collectively, the ETP 2008 Senior Notes). We used the proceeds of approximately $1.48 billion (net of bond discounts of $8.2 million and other offering costs of $10.8 million) from the issuance of the ETP 2008 Senior Notes to repay borrowings and accrued interest outstanding under our $500.0 million, 364-day term loan credit facility and to repay a portion of amount outstanding under the ETP Credit Facility. Interest on the ETP 2008 Senior Notes is payable semiannually on January 1 and July 1 of each year. The Partnership may redeem some or all of the ETP 2008 Senior Notes at any time, or from time to time, pursuant to the terms of the indenture. The ETP 2008 Senior Notes have been registered under the Securities Act of 1933 (as amended) pursuant to our Registration Statement on Form S-3ASR, as supplemented by the Prospectus Supplement dated March 25, 2008, filed with the SEC on March 26, 2008.

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

ETP Credit Facility

The ETP Credit Facility is 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 March 31, 2008, there was a balance of $492.0 million in revolving credit loans (with no outstanding balance in swingline loans) and $61.5 million in letters of credit. The weighted average interest rate on the total amount outstanding at March 31, 2008, was 4.183%. The total amount available under the ETP Credit Facility, as of March 31, 2008, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $1.4 billion. 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 12, 2008, we borrowed the entire amount available under our $500.0 million, 364-day term loan credit facility (the 364-Day Credit Facility) 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 the Base Rate for a designated period. The indebtedness under the 364-Day Credit Facility is unsecured and is not guaranteed by us or any of our 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 contained covenants similar to the covenants of the ETP Credit Facility. On March 28, 2008 we used proceeds from our ETP 2008 Senior Notes offering (see above) to retire this debt.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the HOLP Credit Facility) is available to HOLP through June 30, 2011 which may be expanded to $150.0 million. The HOLP Credit Facility has a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on HOLP s Leverage Ratio, as defined in the HOLP Credit Facility credit agreement, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, sale of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Credit Facility. As of March 31, 2008, there was no balance outstanding on the revolving credit loans. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Credit Facility. There were outstanding letters of credit of $1.0 million at March 31, 2008. The sum of the loans made under the HOLP Credit Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Credit Facility. The amount available at March 31, 2008 was $74.0 million.

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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 March 31, 2008 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. Our General Partner s incentive distributions rights entitle it to receive incentive distributions to the extent that quarterly distributions to our Unitholders exceed $0.275 per unit (which amount represents $1.10 per unit on an annualized basis).

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

On April 24, 2008, we declared a per-unit cash distribution of $0.86875 ($3.475 per unit on an annualized basis) for the quarter ended March 31, 2008, which will be paid on May 15, 2008 to Unitholders of record at the close of business on May 5, 2008.

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 Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K.

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Our commodity-related price risk management assets and liabilities as of March 31, 2008 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	18,287,500	2008-2010	$ 2,729
Swing Swaps IFERC	Gas	(16,690,000)	2008-2009	2,095
Fixed Swaps/Futures	Gas	(22,070,000)	2008-2009	(14,763)
Forward Physical Contracts	Gas	(124,935)	2008	1,313
Options	Gas	(490,000)	2008	(14)
Forwards/Swaps in Gallons	Propane	2,310,000	2008-2009	658
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	25,865,000	2008-2009	$ 3,404
Swing Swaps IFERC	Gas	(17,300,000)	2008	(7,882)
Forward Physical Contracts	Gas		2008	918
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	825,000	2008-2009	$ (76)
Fixed Swaps/Futures	Gas	(182,500)	2008-2009	(1,654)

Credit Risk

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

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

Sensitivity Analysis

The table below summarizes our commodity-related financial derivative instruments and fair values as of March 31, 2008. It also assumes a hypothetical 10% change in the underlying price of the commodity and its effect.

	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Non-Trading Derivatives			
Basis Swaps IFERC/NYMEX	19,112,500	$ 2,653	$ 472
Swing Swaps IFERC	(16,690,000)	2,095	5,874
Fixed Swaps/Futures	(22,252,500)	(16,417)	22,790
Forward Physical Contracts	(124,935)	1,313	3,538
Options	(490,000)	(14)	14
Forwards/Swaps in Gallons	2,310,000	658	540
Trading Derivatives:			
Basis Swaps IFERC/NYMEX	25,865,000	$ 3,404	$ 530
Swing Swaps IFERC	(17,300,000)	(7,882)	3,559
Forward Physical Contracts		918	1,742

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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 facilities will also increase. At March 31, 2008, we had $492.0 million 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 $4.0 million in interest expense and other income, in the aggregate, on an annual basis.

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

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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 March 31, 2008. 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

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a) 15 or Rule 15d 15(f) of the Exchange Act) during the three months ended March 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for our previous year ended August 31, 2007 and Note 12 Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Condensed Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Form 10-Q for the three-month period ended March 31, 2008.

ITEM 1A. RISK FACTORS

In addition to the risks described in our Report on Form 10-K for our previous fiscal 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 the FERC under authority of the Natural Gas Act (NGA). We allegedly violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. Our Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to the FERC-approved rates, terms and conditions of service. The allegations related to the Oasis pipeline include claims that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at 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.

In its Order and Notice, the FERC is seeking $70.1 million in disgorgement of profits, plus interest, and $97.5 million in civil penalties relating to these matters. The FERC has taken the position that, once it receives our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. On August 27, 2007, ETP filed a request for rehearing of the Order and Notice. On December 20, 2007, the FERC issued an order denying rehearing and directed FERC Staff to file a brief recommending disposition of issues by order or by evidentiary hearing. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC s claims and requested a dismissal of the FERC proceeding. On February 14, 2008, the Enforcement Staff of the FERC filed a brief recommending that the FERC refer various matters relating to its market manipulation allegations for an evidentiary hearing before a FERC administrative law judge. The Enforcement Staff also recommended that FERC issue an order assessing the $15.5 million portion of the above-referenced penalty against ETP with respect to the allegations related to ETP s Oasis Pipeline and that the Oasis-related penalty assessment, if not paid, then be referred by the FERC to a federal district court for *de novo* review. The Enforcement Staff also recommended that the FERC impose certain changes in Oasis business operations and refunds to certain Oasis customers as previously proposed in the Order and Notice. Finally, the Enforcement Staff recommended that the FERC pursue market manipulation claims related to ETP s trading activities in October 2005, for November 2005 monthly deliveries, a period not previously covered by FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month. If the claims related to this additional month are pursued by the FERC, the total amount of civil penalties and disgorgement of profits sought by the FERC would be approximately $200.0 million. On March 31, 2008, we responded to the Enforcement Staff s brief. The FERC has not taken any substantive action related to these recommendations of the Enforcement Staff.

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

On July 26, 2007, the United States Commodity Futures Trading Commission (the CFTC) filed suit in United States District Court for the Northern District of Texas alleging that we violated provisions of the Commodity Exchange Act by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, ETP entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, ETP agreed to pay the CFTC $10.0 million and the CFTC agreed to release ETP and its affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that ETP is permanently enjoined from attempting to manipulate the price of any commodity in interstate commerce in violation of the Commodity Exchange Act. By consenting to the entry of the Consent Order, ETP neither admitted nor denied the allegations made by the CFTC in this proceeding. The settlement reduced our existing accrual and was paid from cash flow from operations on March 19, 2008.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE for damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETE for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETE contains an additional allegation that the defendants transported gas in a manner that favored their affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producers/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We have filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable. The claimants have agreed to a four-week stay of the arbitration through May 22, 2008 while they evaluate the state court pleading.

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. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The 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. The plaintiffs have requested certification of their suit as a class action, and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008 we filed a motion to dismiss the complaint.

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

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 accrual related to these matters. In accordance with applicable accounting standards, we will review the amount of our existing 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.

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.)

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	Exhibit Number	Description
(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.
(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.

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		Exhibit Number	Description
(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.
(51)		4.16	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(46)		10.1	Amended and Restated Credit Agreement, dated July 20, 2007, among Energy Transfer Partners, L.P., the borrower and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC as senior managing agents, and other lenders party hereto.
(1)		10.2	Form of Note Purchase Agreement (June 25, 1996).
(2)		10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.
(3)		10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.
(5)		10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.
(6)		10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
(7)		10.2.5	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(8)		10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(11)		10.2.7	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(15)	**	10.6.3	Second Amended and Restated Restricted Unit Plan dated as of February 4, 2002.
(49)		10.6.5	Form of Grant Agreement.
(45)	**	10.6.6	Amended and Restated 2004 Unit Plan.
(50)	**	10.6.7	Midstream Bonus Plan.
(4)		10.16	Note Purchase Agreement dated as of November 19, 1997.
(5)		10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement.

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		Exhibit Number	Description
(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.
(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.

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	Exhibit Number	Description
(45)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(47)	21.1	List of Subsidiaries.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
** Denotes a management contract or compensatory plan or arrangement.
(1) Incorporated by reference to the same numbered Exhibit to Registrant s Registration Statement of Form S-1, File No. 333-04018, filed with the Commission on June 21, 1996.
(2) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 1996.
(3) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended February 28, 1997.
(4) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended May 31, 1998.
(5) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1998.
(6) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1999.
(7) Incorporated by reference to the Exhibit 10.16.3 to the Registrant s Form 10-Q for the quarter ended May 31, 2000.
(8) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated August 23, 2000.
(9) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.
(10) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2001.
(11) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2001.

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(14) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended November 30, 2001.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2002.
(16) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2002.
(17) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated February 4, 2002.
(18) Incorporated by reference as the same numbered exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(19) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(20) Incorporated by reference to Annex A of the Registrant s Schedule 14A Proxy Statement filed May 18, 2004.
(21) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed November 1, 2004.
(22) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed January 19, 2005.
(23) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed January 19, 2005.
(24) Incorporated by reference to Exhibit 4.3 to the Registrant s Form 8-K filed January 19, 2005.
(25) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed February 1, 2005.
(26) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed February 1, 2005.
(27) Incorporated by reference to Exhibit 3.1.7 to the Registrant s Form 8-K filed March 16, 2005.
(28) Incorporated by reference to Exhibit 3.1.8 to the Registrant s Form 8-K filed February 9, 2006.
(29) Incorporated by reference to Exhibit 10.45 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(30) Incorporated by reference to Exhibit 10.39.1 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(31) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed August 2, 2005.
(32) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed August 2, 2005.
(33) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K/A for the year ended August 31, 2005.
(34) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed December 16, 2005.
(35) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed December 16, 2005.
(36) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed October 25, 2006.
(37) Incorporated by reference to Exhibit 3.1.10 to the Registrant s Form 8-K filed November 3, 2006.
(38) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2006.

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(39) Incorporated by reference to Exhibit 3.1.9 to the Registrant s Form 8-K filed May 3, 2006.
(40) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed September 18, 2006.
(41) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed September 18, 2006.
(42) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed September 18, 2006.
(43) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2006.
(44) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2007.
(45) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2007.
(46) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K filed on July 23, 2007.
(47) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed on October 9, 2007.
(48) Incorporated by reference to Exhibit 3.1.11 to the Registrant s Form 8-K filed on January 18, 2008.
(49) Incorporated by reference to Exhibit 10.6.5 to the Registrant s Form 10-Q for the quarter ended November 30, 2007.
(50) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed March 3, 2008.
(51) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed March 28, 2008.

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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: May 12, 2008

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