Energy Transfer Partners, L.P.
Form 10-Q
May 11, 2009
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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, 2009

OR

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

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue, Dallas, Texas 75219

(Address of principal executive offices and zip code)

Registrant s telephone number, including area code: (214) 981-0700

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

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

At May 7, 2009, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 168,786,459 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 December 31, 2008 filed with the Securities and Exchange Commission on March 2, 2009.

Definitions

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

/d	per day
Btu	British thermal unit, an energy measurement
Capacity	Capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels.
Dth	Million British thermal units (dekatherm). A therm factor is used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used.
Mcf	thousand cubic feet
MMBtu	million British thermal unit
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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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, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 105,956	$ 91,902
Marketable securities	5,949	5,915
Accounts receivable, net of allowance for doubtful accounts	489,063	591,257
Accounts receivable from related companies	33,790	17,895
Inventories	144,607	272,348
Deposits paid to vendors	38,468	78,237
Exchanges receivable	23,900	45,209
Price risk management assets	3,170	5,423
Prepaid expenses and other current assets	56,429	75,215
Total current assets	901,332	1,183,401
PROPERTY, PLANT AND EQUIPMENT, net	8,432,979	8,296,085
ADVANCES TO AND INVESTMENTS IN AFFILIATES	129,840	10,110
GOODWILL	734,949	743,694
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	400,519	394,199
Total assets	$ 10,599,619	$ 10,627,489

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, 2009	December 31, 2008
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 309,601	$ 381,135
Accounts payable to related companies	18,543	34,547
Exchanges payable	28,152	54,636
Customer advances and deposits	55,699	106,679
Accrued wages and benefits	59,735	64,692
Accrued capital expenditures	84,908	153,230
Accrued and other current liabilities	113,943	108,604
Price risk management liabilities	46,203	94,978
Interest payable	83,644	106,259
Deferred income taxes	258	589
Current maturities of long-term debt	44,496	45,198
Total current liabilities	845,182	1,150,547
LONG-TERM DEBT, less current maturities	5,587,915	5,618,549
DEFERRED INCOME TAXES	108,523	100,597
OTHER NON-CURRENT LIABILITIES	14,540	14,727
COMMITMENTS AND CONTINGENCIES (Note 14)		
	6,556,160	6,884,420
PARTNERS CAPITAL:		
General Partner	167,595	161,159
Limited Partners:		
Common Unitholders (159,011,459 and 152,102,471 units authorized, issued and outstanding at March 31, 2009 and December 31, 2008, respectively)	3,884,835	3,578,997
Class E Unitholders (8,853,832 units authorized, issued and outstanding - held by subsidiary and reported as treasury units)		
Accumulated other comprehensive income (loss)	(8,971)	2,913
Total partners capital	4,043,459	3,743,069
Total liabilities and partners capital	$ 10,599,619	$ 10,627,489

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Three Months Ended March 31, 2009	2008 As Adjusted (Note 2)
REVENUES:		
Natural gas operations	$ 1,111,955	$ 2,007,847
Retail propane	487,907	598,138
Other	30,238	33,386
Total revenues	1,630,100	2,639,371
COSTS AND EXPENSES:		
Cost of products sold - natural gas operations	732,113	1,577,268
Cost of products sold - retail propane	220,222	392,555
Cost of products sold - other	6,804	9,895
Operating expenses	181,773	178,970
Depreciation and amortization	72,603	58,828
Selling, general and administrative	55,732	48,369
Total costs and expenses	1,269,247	2,265,885
OPERATING INCOME	360,853	373,486
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(82,045)	(55,549)
Equity in earnings of affiliates	497	74
Loss on disposal of assets	(426)	(1,451)
Gains (losses) on non-hedged interest rate derivatives	13,726	(600)
Allowance for equity funds used during construction	20,427	9,888
Other, net	1,067	8,349
INCOME BEFORE INCOME TAX EXPENSE	314,099	334,197
Income tax expense	6,932	5,862
NET INCOME	307,167	328,335
GENERAL PARTNER S INTEREST IN NET INCOME	90,290	74,364
LIMITED PARTNERS INTEREST IN NET INCOME	$ 216,877	$ 253,971
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.37	$ 1.78

BASIC AVERAGE NUMBER OF UNITS OUTSTANDING		157,009,238		142,762,265
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$	1.37	$	1.77
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING		157,390,400		143,197,800

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

(unaudited)

	Three Months Ended March 31,	
	2009	**2008**
Net income	$ 307,167	$ 328,335
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(10,549)	(22,691)
Change in value of derivative instruments accounted for as cash flow hedges	(1,386)	(6,221)
Change in value of available-for-sale securities	51	(167)
	(11,884)	(29,079)
Comprehensive income	$ 295,283	$ 299,256

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, 2009

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2008	$ 161,159	$ 3,578,997	$ 2,913	$ 3,743,069
Distributions to partners	(83,860)	(142,108)		(225,968)
Issuance of units in public offering		225,863		225,863
Capital contribution from General Partner	4,795			4,795
Contribution receivable from General Partner	(4,795)			(4,795)
Distributions on unvested unit awards		(952)		(952)
Tax effect of remedial income allocation from tax amortization of goodwill		(942)		(942)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings		6,793		6,793
Non-cash executive compensation expense	6	307		313
Other comprehensive loss, net of tax			(11,884)	(11,884)
Net income	90,290	216,877		307,167
Balance, March 31, 2009	$ 167,595	$ 3,884,835	$ (8,971)	$ 4,043,459

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, 2009	Three Months Ended March 31, 2008
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 429,181	$ 374,056
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(5,511)	(40,753)
Capital expenditures (excluding allowance for equity funds used during construction)	(255,876)	(482,742)
Contributions in aid of construction costs	1,877	39,970
(Advances to) repayments from affiliates, net	(119,850)	63,534
Proceeds from the sale of assets	2,925	10,433
Net cash used in investing activities	(376,435)	(409,558)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	487,388	2,995,405
Principal payments on debt	(525,802)	(2,658,498)
Net proceeds from issuance of Limited Partner Units	225,863	34,984
Distributions to partners	(225,968)	(251,557)
Debt issuance costs	(173)	(19,039)
Net cash provided by (used in) financing activities	(38,692)	101,295
INCREASE IN CASH AND CASH EQUIVALENTS	14,054	65,793
CASH AND CASH EQUIVALENTS, beginning of period	91,902	56,467
CASH AND CASH EQUIVALENTS, end of period	$ 105,956	$ 122,260

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, 2008, 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, ETP , we or the Partnership) as of March 31, 2009 and for the three-month periods ended March 31, 2009 and 2008, 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, 2009, and the Partnership s results of operations and cash flows for the three-month periods ended March 31, 2009 and 2008. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2008, as filed with the SEC on March 2, 2009.

Certain prior period amounts have been reclassified to conform with the 2009 presentation. These reclassifications had no impact on net income or total partners capital.

Business Operations

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

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

Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, L.L.C. (ETC MEP), all of which are Delaware limited liability companies engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

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

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

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

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

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

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

Use of Estimates

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

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and intrastate transportation and storage 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, 2009 and 2008 represent the actual results in all material respects.

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

New Accounting Standards and Changes to Significant Accounting Policies

A retrospective adjustment has been made to prior period income per limited partner unit presented in our consolidated statement of operations to conform to current period presentation related to our adoption of EITF 07-4. EITF 07-4 and other recently adopted accounting standards are discussed below.

Emerging Issues Task Force Issue No. 07-4, *Application of the Two Class Method Under FASB Statement No. 128, to Master Limited Partnerships* (EITF 07-4). The FASB ratified the final consensus on EITF 07-4 on March 26, 2008. The key elements of the final consensus relate to: (a) the scope of the issue; (b) when Incentive Distribution Rights (IDRs) are considered participating securities under the two-class method for Earnings Per Share (EPS); (c) the calculation provisions; and (d) the transition and effective date. EITF 07-4 addresses how current period earnings of a master limited partnership (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

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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. We recorded and disclosed EPS information following the previous GAAP until January 1, 2009. We adopted EITF 07-4 as required on January 1, 2009 and have applied EITF 07-4 retrospectively; therefore, earnings per unit amounts for prior periods have been restated.

Based on the terms of our partnership agreement, EITF 07-4 requires us to allocate any excess undistributed earnings to the general partner and limited partners based on their respective ownership interests, with none of the excess undistributed earnings allocated to the IDRs. Prior to the adoption of EITF 07-4, we allocated a portion of the excess undistributed earnings to the IDRs. Thus, for periods where earnings exceed distributions, EITF 07-4 will result in a higher income per limited partner unit than our previous approach. For periods where distributions exceed earnings, the calculation of income per limited partner unit under EITF 07-4 is consistent with our previous approach. Thus, the adoption of EITF 07-4 will not have an impact on those periods.

The following financial table sets forth the effect of the retrospective application of EITF 07-4 on income per limited partner unit for the three months ended March 31, 2008:

	Originally Reported	As Adjusted
Basic net income per limited partner unit	$ 1.34	$ 1.78
Diluted net income per limited partner unit	$ 1.34	$ 1.77

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

- Acquisition costs are generally expensed as incurred;
- Noncontrolling interests (previously referred to as minority interests) are valued at fair value at the acquisition date;
- In-process research and development is recorded at fair value as an indefinite-lived intangible asset at the acquisition date;
- Restructuring costs associated with a business combination are generally expensed subsequent to the acquisition date; and
- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date are recorded in income taxes.

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. SFAS 141R has not been applied to any transactions presented in these condensed consolidated financial statements. Our adoption of SFAS 141R on January 1, 2009 did not have an immediate impact on our financial position or results of operations.

Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities An Amendment of FASB Statement No. 133* (SFAS 161). Issued in March 2008, 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. SFAS 161 only affects disclosure requirements; therefore, our adoption of this statement effective January 1, 2009 did not impact our financial position or results of operations.

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

Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations* (EITF 08-6). EITF 08-6 establishes the requirements for initial measurement of an equity method investment, including the accounting for contingent consideration related to the acquisition of an equity method investment. EITF 08-6 also clarifies the accounting for (1) an other-than-temporary impairment of an equity method investment and (2) changes in level of ownership or degree of influence with respect to an equity method investment. Our adoption of EITF 08-6 on January 1, 2009 did not have a material impact on our financial condition or results of operations.

Statement of Financial Accounting Standards Staff Position (FSP) SFAS 157-2, *Effective Date of FASB Statement No. 157 (FSP 157-2)*. FSP 157-2 deferred the effective date of SFAS 157 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), such as impaired nonfinancial assets and certain assets and liabilities acquired in business combinations. Our adoption of FSP 157-2 on January 1, 2009 did not impact our financial condition or results of operations.

3. 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 changes in value.

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

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

	Three Months Ended March 31,	
	2009	2008
Net income	$ 307,167	$ 328,335
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	72,603	58,828
Amortization of finance costs charged to interest	1,990	1,074
Provision for loss on accounts receivable	1,312	1,204
Non-cash unit-based compensation expense	6,801	8,086
Non-cash executive compensation expense	313	312
Deferred income taxes	6,719	2,857
Loss on disposal of assets	426	1,451
Allowance for equity funds used during construction	(20,427)	(9,888)
Distributions on unvested awards	(952)	
Distributed earnings of affiliates, net	328	1,651
Other non-cash	611	
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	100,905	(248,114)
Accounts receivable from related companies	(15,895)	(12,805)
Inventories	127,742	248,217

Deposits paid to vendors	39,769	(18,202)
Exchanges receivable	21,309	(6,885)
Prepaid expenses and other	18,787	(2,824)
Intangibles and other long-term assets	(6,673)	(3,186)
Accounts payable	(59,795)	114,815
Accounts payable to related companies	(16,004)	(22,308)
Exchanges payable	(26,484)	3,150
Customer advances and deposits	(51,126)	(34,803)
Accrued wages and benefits	(4,985)	(11,814)
Accrued and other current liabilities	5,942	15,117
Interest payable	(22,629)	(18,047)
Other non-current liabilities	(187)	1,667
Price risk management liabilities, net	(58,386)	(23,832)
Net cash provided by operating activities	$ 429,181	$ 374,056

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

	Three Months Ended March 31, 2009	2008
NON-CASH INVESTING ACTIVITIES:		
Investment in Calpine Corporation received in exchange for accounts receivable	$	$ 10,816
Capital expenditures accrued	$ 84,908	$ 152,954
NON-CASH FINANCING ACTIVITIES:		
Capital contribution receivable from general partner	$ 4,795	$ 747
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$	$ 2,693
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid for interest, net of interest capitalized	$ 108,461	$ 83,438
Cash received for income taxes	$ (24)	$ (353)

4. ACCOUNTS RECEIVABLE:

Accounts receivable consisted of the following:

	March 31, 2009	December 31, 2008
Midstream and intrastate transportation and storage	$ 333,676	$ 415,507
Interstate transportation	30,469	29,309
Propane	133,480	155,191
Less - allowance for doubtful accounts	(8,562)	(8,750)
Total, net	$ 489,063	$ 591,257

The activity in the allowance for doubtful accounts for the propane operations during the three months ended March 31, 2009 consisted of the following:

Balance, December 31, 2008	$ 8,750
Accounts receivable written off, net of recoveries	(1,500)
Provision for loss on accounts receivable	1,312
Balance, March 31, 2009	$ 8,562

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5. INVENTORIES:

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

Inventories consisted of the following:

	March 31, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 84,762	$ 184,727
Propane	36,390	63,967
Appliances, parts and fittings and other	23,455	23,654
Total inventories	$ 144,607	$ 272,348

During the three months ended March 31, 2009, we recorded a lower of cost or market adjustment of $44.6 million for natural gas inventory to reflect market values which were less than the weighted-average cost. No lower of cost or market adjustments were recorded for the three months ended March 31, 2008.

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

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

	March 31, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Non-compete agreements (3 to 15 years)	$ 40,301	$ (25,529)	$ 40,301	$ (24,374)
Customer lists (3 to 15 years)	153,234	(43,224)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(4,217)	23,015	(3,744)
Other (10 years)	2,677	(2,439)	2,677	(2,244)
Total amortizable intangible assets	219,227	(75,409)	210,330	(70,092)
Non-amortizable intangible assets - Trademarks	75,503		75,667	
Total intangible assets	294,730	(75,409)	285,997	(70,092)
Other long-term assets:				
Financing costs (3 to 15 years)	59,281	(18,464)	59,108	(16,586)
Regulatory assets	106,503	(6,823)	98,560	(5,941)
Other	40,701		43,153	
Total intangibles and other long-term assets	$ 501,215	$ (100,696)	$ 486,818	$ (92,619)

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

	Three Months Ended March 31, 2009	2008
Reported in depreciation and amortization	$ 4,709	$ 4,299
Reported in interest expense	$ 1,878	$ 1,282

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

Years Ending December 31:	
2010	$ 25,680
2011	24,014
2012	20,429
2013	14,999
2014	14,409

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review goodwill and non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of December 31 for our interstate segment and as of August 31 for all others. No impairment of intangible assets was required for the three months ended March 31, 2009 or 2008. In December 2008, we recorded an impairment of the entire goodwill balance of $11.4 million related to the Canyon Gathering System. No goodwill impairments were recorded during the periods presented.

A decrease in goodwill of $8.7 million was recorded during the three months ended March 31, 2009 in connection with purchase price allocation adjustments related to prior acquisitions of propane businesses.

7. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

We are party to an agreement with Kinder Morgan Energy Partners, L.P. (KMP) for a 50/50 joint development of Midcontinent Express pipeline (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. The first phase of the pipeline was placed in interim service in April 2009 and the second phase of the pipeline is expected to be in service by the third quarter of 2009. In July 2008, MEP completed an open season with respect to a capacity expansion of MEP from the original planned capacity of 1.5 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to a planned interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional 300 MMcf/d of capacity was fully subscribed as a result of this open season. The planned expansion of capacity would be added through the installation of additional compression on this segment of the pipeline and is pending approval from the Federal Energy Regulatory Commission (FERC).

On January 9, 2009, MEP filed an amended application to revise its initial transportation rates to reflect an increase in projected costs for the project; the amended application was approved by the FERC on March 25, 2009.

Fayetteville Express Pipeline LLC

We are party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 187-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. FEP, the entity formed to own and operate this pipeline, initiated public review of the project pursuant to the FERC s National Environmental Policy Act (NEPA) pre-filing review process in November 2008. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. Pending necessary regulatory approvals, the pipeline project is expected to be in service by early 2011. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America (NGPL) in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Knight, Inc. Knight owns the general partner of KMP. Pursuant to our agreement with KMP related to this project, we and KMP are each obligated to fund 50% of the equity necessary to construct the project.

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Capital Contributions to Affiliates

During the three months ended March 31, 2009, we contributed $119.9 million to our joint ventures ($111.0 million to MEP and $8.9 million to FEP). We expect that we will make capital contributions to MEP of between $345.0 million and $365.0 million and capital contributions to FEP of between $200.0 million and $220.0 million during the last nine months of 2009 to fund expenditures for the projects. If MEP obtains long-term financing in 2009 following completion of the base project, an additional capital contribution of $200.0 million to $250.0 million may be required.

8. FAIR VALUE MEASUREMENTS:

The following table summarizes the fair value of our financial assets and liabilities as of March 31, 2009 and December 31, 2008, based on inputs used to derive their fair values in accordance with SFAS 157:

		Fair Value Measurements at March 31, 2009 Using			Fair Value Measurements at December 31, 2008 Using	
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets						
Marketable securities	$ 5,949	$ 5,949	$	$ 5,915	$ 5,915	$
Commodity derivatives	3,211	1,046	2,165	111,513	106,090	5,423
Interest rate swap derivatives	1,005		1,005			
Liabilities						
Commodity derivatives	(20,565)	(12,132)	(8,433)	(43,336)		(43,336)
Interest rate swap derivatives	(37,770)		(37,770)	(51,642)		(51,642)
	$ (48,170)	$ (5,137)	$ (43,033)	$ 22,450	$ 112,005	$ (89,555)

9. INCOME TAXES:

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

	Three Months Ended March 31, 2009	2008
Current expense (benefit):		
Federal	$ (4,626)	$ (523)
State	3,492	3,272
Total	(1,134)	2,749
Deferred expense:		
Federal	7,391	2,834
State	675	279

Total	8,066	3,113
Total tax expense	$ 6,932	$ 5,862
Effective tax rate	2.2%	1.8%

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.

10. INCOME PER LIMITED PARTNER UNIT:

Our net income is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the Incentive Distribution Rights (IDRs) pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. The adoption of EITF 07-4 on January 1, 2009, as discussed in Note 2, required us to change our calculation of earnings per unit during periods where earnings exceeded distributions. Under EITF 07-4, earnings in excess of distributions are now allocated to the General Partner and Limited Partners based on their respective ownership interests. Previously, a portion of earnings in excess of distributions had been allocated to the General Partner with respect to the IDRs. We have applied EITF 07-4 retrospectively; therefore, earnings per unit amounts for prior periods have been restated.

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

	Three Months Ended March 31, 2009	2008
Net income	$ 307,167	$ 328,335
General Partner s interest in net income	90,290	74,364
Limited Partners interest in net income	216,877	253,971
Distributions on employee unit awards, net of allocation to General Partner	(1,004)	
Net income available to Limited Partners	$ 215,873	$ 253,971
Weighted average Limited Partner units basic	157,009,238	142,762,265
Basic net income per Limited Partner unit	$ 1.37	$ 1.78
Weighted average Limited Partner units	157,009,238	142,762,265
Dilutive effect of Unit Grants	381,162	435,535
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants	157,390,400	143,197,800
Diluted net income per Limited Partner unit	$ 1.37	$ 1.77

11. DEBT OBLIGATIONS:

ETP Senior Notes

2009 ETP Notes

Subsequent to March 31, 2009, we completed a public offering of $350.0 million aggregate principal amount of our 8.50% Senior Notes due 2014 and $650.0 million aggregate principal amount of our 9.00% Senior Notes due 2019 (collectively the 2009 ETP Notes). The sale of the 2009 ETP Notes closed on April 7, 2009 and we used the net proceeds of approximately $993.6 million from the offering to repay all borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

The 2009 ETP Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the 2009 ETP Notes is not guaranteed by any of the Partnership s subsidiaries. As a result, the 2009 ETP 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 2009 ETP Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity, under the Amended and Restated Credit Agreement). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. 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 and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

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As of March 31, 2009, there was a balance outstanding on the ETP Credit Facility of $882.0 million in revolving credit loans and approximately $60.0 million in letters of credit. The weighted average interest rate on the total amount outstanding at March 31, 2009, was 1.86%. The total amount available under the ETP Credit Facility, as of March 31, 2009 which is reduced by any letters of credit, was approximately $1.06 billion.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the HOLP Credit Facility) available to HOLP through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Credit Facility. At March 31, 2009, there was no outstanding balance in revolving credit loans and $1.0 million in outstanding letters of credit. The amount available as of March 31, 2009 was $74.0 million.

Covenants Related to Our Credit Agreements

We are in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at March 31, 2009.

12. PARTNERS CAPITAL:

Common Units Issued

The change in Common Units during the three-month period ended March 31, 2009 is as follows:

	Number of Units
Balance, December 31, 2008	152,102,471
Common Units issued in connection with a public offering	6,900,000
Issuance of Common Units under equity incentive plans	8,988
Balance, March 31, 2009	159,011,459

On January 27, 2009, we closed a public offering of 6,900,000 Common Units at $34.05 per Common Unit. Net proceeds of approximately $225.9 million from the offering were used to repay outstanding borrowings under the ETP Credit Facility.

Subsequent to March 31, 2009, we closed a public offering of 8,500,000 Common Units representing limited partner interests at $37.55 per Common Unit. In connection with this public offering, we also granted the underwriters a 30-day option to purchase up to an aggregate of 1,275,000 additional Common Units on the same terms. The offering closed on April 21, 2009 and the underwriters exercised their option to purchase additional Common Units in full on April 24, 2009. Net proceeds of approximately $352.4 million from the offering will be used to fund capital expenditures and capital contributions to joint venture entities related to pipeline construction projects as well as for general partnership purposes. The units have been registered under the Securities Act of 1933, as amended, pursuant to a Registration Statement on Form S-3ASR.

Quarterly Distributions of Available Cash

On February 13, 2009, we paid a per unit cash distribution related to the three months ended December 31, 2008 of $0.89375 per Common Unit ($3.575 per Limited Partner Unit annualized) to Unitholders of record at the close of business on February 6, 2009. We paid $83.9 million in the aggregate for ETP GP s 2% general partner interest in the Partnership and its Incentive Distribution Rights for the three months ended December 31, 2008.

On April 28, 2009, we announced the declaration of a cash distribution for the three months ended March 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on May 15, 2009 to Unitholders of record at the close of business on May 8, 2009.

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Total distributions declared (all from Available Cash from Operating Surplus) related to the three months ended March 31, 2009 were as follows:

Limited Partners -	
Common Units	$ 150,853
Class E Units	3,121
General Partners -	
2% Ownership	4,860
Incentive Distribution Rights	84,146
	$ 242,980

Accumulated Other Comprehensive Income

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

	March 31, 2009	December 31, 2008
Net gain (loss) on commodity related hedges	$ (3,128)	$ 8,735
Net gain on interest rate hedges	89	161
Unrealized losses on available-for-sale securities	(5,932)	(5,983)
Total AOCI, net of tax	$ (8,971)	$ 2,913

13. <u>UNIT-BASED COMPENSATION PLANS</u>:
Employee Grants

The following table shows the activity of the awards granted during the three months ended March 31, 2009:

	Three-Year Performance Vesting (1)		Five-Year Service Vesting (2)		Other (3)		Total	
	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2008	150,852	$ 43.96	1,205,430	$ 35.87	8,976	$ 43.48	1,365,258	$ 36.81
Awards granted			35,850	34.60			35,850	34.60
Awards vested			(8,800)	46.00			(8,800)	46.00
Awards forfeited	(834)	40.69	(7,776)	37.10			(8,610)	37.45
Unvested awards as of March 31, 2009	150,018	$ 43.98	1,224,704	$ 35.75	8,976	$ 43.48	1,383,698	$ 36.69

(1) Includes awards subject to performance objectives and continued employment.

(2) Includes awards for which vesting is subject to continued employment.
(3) Includes special grants and awards issued with other vesting conditions.

As of March 31, 2009, a total of 4,759,630 ETP Common Units remain available to be awarded under the 2008 Incentive Plan.

We recognized non-cash compensation expense related to employee grants under our unit-based compensation plans of $6.8 million and $5.9 million for the three months ended March 31, 2009 and 2008, respectively. The total expected non-cash compensation expense to be recognized related to the unvested employee awards as of March 31, 2009 is:

Years Ending December 31:	
2009 (remainder)	$ 14,501
2010	10,516
2011	6,176
2012	3,235
2013	1,056

Director Grants

There were no new Director Grants, or awards vested during the three months ended March 31, 2009.

We recognized non-cash compensation expense related to director grants under our unit-based compensation plans of $0.04 million for each of the three month periods ended March 31, 2009 and 2008.

Related Party Awards

During 2007 and 2008, a partnership (McReynolds Energy 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. As of March 31, 2009, rights related to 695,000 unvested ETE units remained outstanding. For the three months ended March 31, 2009 and 2008, we recognized non-cash compensation expense, net of forfeitures, of $1.8 million and $2.2 million, respectively.

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

Regulatory Matters

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (NGA) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern s tariff rates and fuel charges are now final for the period of the settlement. Transwestern is not required to file a new rate case until October 1, 2011.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern s existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern s existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity (Order). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. On December 17, 2007, two parties filed requests for rehearing of the Order and on December 20, 2007, one party filed a motion to stay the Order. On February 21, 2008, the FERC reaffirmed its decision in the Order; thus, Transwestern notified customers of the commencement of construction in January 2008. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was placed in service in March 2009.

Guarantees

We have guaranteed 50% of the obligations of MEP under its $1.40 billion senior revolving credit facility (the MEP Facility), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. The MEP Facility is syndicated among multiple financial institutions. As a result of the Lehman Brothers bankruptcy in 2008, the MEP Facility has effectively been reduced by the Lehman Brothers affiliate s commitment of approximately $100.0 million. However, the MEP Facility is not in default, and the commitments of the other lending banks remain unchanged.

As of March 31, 2009, MEP had $1.22 billion of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP s outstanding borrowings and letters of credit were $609.1 million and $16.7 million, respectively, as of March 31, 2009.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a long-term purchase contract for approximately 79.0 million gallons of propane per year that contains a two year cancellation provision and a seven year contract to purchase not less than 90.0 million gallons per year. 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 has been included in operating expenses in the accompanying statements of operations and totaled approximately $6.0 million and $8.2 million for the three months ended March 31, 2009 and 2008, respectively.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverages and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

FERC/CFTC and Related Matters. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC has alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleges that we violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. Finally, the FERC alleged that our Oasis pipeline, a pipeline that 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, 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. As discussed below, in January 2009 we entered into a settlement agreement with FERC Enforcement Staff pursuant to which all claims against Oasis were settled with no obligation for Oasis to pay any civil penalties to the FERC or make any other payment, and in February 2009, the FERC approved the terms of this settlement agreement in its entirety and without modification. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at market-based prices, which activity accounted for less than 1.0% of our operating income for our 2008 year. If the FERC is successful in revoking our blanket marketing authority, our sales of natural gas at market-based prices would be limited to sales to retail customers (such as utilities and other end-users) and sales from our own production, and any other sales of natural gas by us would be required to be made at contract prices that would be subject to individual FERC approval.

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In its Order and Notice, the FERC specified that it was seeking $54.6 million in disgorgement of profits, plus interest, and $97.5 million in civil penalties relating to its market manipulation claims. 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 the FERC Enforcement 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 the FERC pursue market manipulation claims related to ETP s trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month. If the FERC pursues the claims related to this additional month, the total amount of civil penalties and disgorgement of profits sought by the FERC would be approximately $184.4 million. On March 31, 2008, we responded to the Enforcement Staff s brief.

On May 15, 2008, the FERC ordered hearings to be conducted by FERC administrative law judges with respect to the FERC s Oasis claims and market manipulation claims. The hearing related to the Oasis claims was scheduled to commence in December 2008 with the administrative law judge s initial decisions due by May 11, 2009; however, as discussed below, we entered into a settlement agreement with FERC Enforcement Staff in January 2009, and that agreement was approved by the FERC in its entirety and without modification on February 27, 2009. The hearing related to the market manipulation claims is now scheduled to commence in June 2009 with the administrative law judge s initial decision due by December 3, 2009. The FERC also ordered that, following the completion of the hearings, the administrative law judges make initial findings with respect to whether we engaged in market manipulation in violation of the NGA and FERC regulations. The FERC reserved for itself the issues of possible civil penalties, revocation of our blanket market certificate, and whether we would disgorge any unjust profits. Following the issuance of the administrative law judge s initial decision related to the market manipulation claims, the FERC would then issue an order with respect to each of these matters. On May 23, 2008, we requested rehearing and stay of the FERC s May 15, 2008 order establishing hearing, and we renewed those requests on June 26, 2008. On August 7, 2008, FERC denied rehearing of its May 15, 2008 order. On August 8, 2008, we filed a petition with the U.S. Court of Appeals for the Fifth Circuit to review and set aside FERC s May 15 and August 7, 2008 orders on the grounds that we are entitled to adjudicate FERC s claims in federal district court pursuant to the NGA and the NGPA. On August 28, 2008, we filed an amended petition seeking review of the Order and Notice and the December 20, 2007 order denying rehearing. On April 28, 2009, the Fifth Circuit issued an order dismissing our petition on the grounds that the issues presented in the petition are not ripe for adjudication at this time.

On November 18, 2008, the administrative law judge presiding over the Oasis claims granted our motion for summary disposition of the claim that Oasis unduly discriminated in favor of affiliates regarding the provision of Section 311(a)(2) interstate transportation service. We subsequently entered into an agreement with the Enforcement Staff to settle all of the claims related to Oasis. Pursuant to this agreement, Oasis will not pay any civil penalties to the FERC or make any other payments. On January 5, 2009, this agreement was submitted under seal to FERC by the presiding administrative law judge, for FERC s approval as an uncontested settlement of all Oasis claims. On February 27, 2009, the settlement agreement was approved by the FERC in its entirety and without modification, and the terms of the settlement were made public. As no person sought rehearing of the order approving the settlement within 30 days of such order, the FERC s order has become final and non-appealable. We believe the Oasis settlement, as approved by the FERC, will not have a material adverse effect on our business, financial condition or results of operations.

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.

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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 (CEA) by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, we entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, we agreed to pay the CFTC $10.0 million and the CFTC agreed to release us and our affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that we are permanently enjoined from attempting to manipulate the price of any commodity in interstate commerce in violation of the CEA. By consenting to the entry of the Consent Order, we neither admitted nor denied the allegations made by the CFTC in this proceeding. The settlement reduced our existing accrual and was paid from cash flow from operations in March 2008.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE for damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETE for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETE contains an additional allegation that we and ETE transported gas in a manner that favored our affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of

gas to other parties in the market. We have moved to compel arbitration and/or contested subject-matter jurisdiction in some of these cases. One such case currently is on appeal before the Texas Supreme Court on, among other things, the issue of whether the dispute is arbitrable.

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 producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The claimants have filed a notice of appeal.

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 NYMEX in violation of the CEA. It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, we filed a motion to dismiss the complaint. On June 19, 2008, the plaintiffs filed a response opposing our motion to dismiss. We filed a reply in support of our motion on July 9, 2008. On March 26, 2009, the court issued an order dismissing this complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiff filed with the court a motion for reconsideration of this decision. The court has not taken any action with respect to this motion.

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 our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On July 2, 2008 the plaintiffs filed a response opposing our motion to dismiss. We filed a reply in support of our motion on August 18, 2008. On March 26, 2009, the court issued an order dismissing this complaint for failure to state a claim in all causes of action and for failure to state an anti-trust injury but granted the plaintiffs leave to amend. On April 23, 2009, the plaintiff filed a motion with the court to seek permission to amend its petition in order to assert a claim for common law fraud. The court has not taken any action with respect to this motion.

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

In re Natural Gas Royalties Qui Tam Litigation. MDL Docket No. 1293 (D. WY), Jack Grynberg, an individual, has filed actions against a number of companies, including Transwestern, now transferred to the U.S. District Court for the District of Wyoming, for damages for mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against Transwestern. Transwestern believes that its measurement practices conformed to the terms of its FERC Gas Tariff, which were filed with and approved by the FERC. As a result, Transwestern believes that is has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Transwestern complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal which may be taken from the dismissal of the Grynberg case. A hearing was held on April 24, 2007 regarding Transwestern s Supplemental Brief for Attorneys fees which was filed on January 8, 2007 and the issues are submitted and are awaiting a decision. Grynberg moved to have the cases he appealed remanded to the district court for consideration in light of a recently-issued Supreme Court case. The defendants/appellees opposed the motion. The Tenth Circuit motions panel referred the remand motion to the merits panel to be carried with the appeals. Grynberg s opening brief was filed on or about July 31, 2007. Appellee s opposition brief was filed on or about November 21, 2007. Appellee Transwestern filed its separate response brief on January 11, 2008 and Grynberg s reply brief was filed in June 2008 and the hearing on all briefs was held in September 2008. On March 17, 2009, the Tenth Circuit affirmed the District Court s dismissal. Transwestern does not believe the outcome of this case will have a material adverse effect on its financial position, results of operations or cash flows.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies and American Electric Power Corporation (AEP), were engaged in ongoing litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel Storage Facility (Cushion Gas). This litigation is referred to as the Cushion Gas Litigation . Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the

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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 is appealing the court decision. 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, 2009 and December 31, 2008, accruals of $21.0 million and $20.8 million, respectively, were recorded as accrued and other current liabilities and other non-current liabilities on our condensed consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters.

Environmental

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices, and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (PCBs) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $9.0 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern continues to incur certain costs related to PCBs that could migrate through its pipelines into customers facilities. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing the PCBs. Costs of these remediation activities totaled approximately $0.1 million for the three months ended March 31, 2009. There were no remediation costs incurred for the three months ended March 31, 2008. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers, and accordingly, no accrual has been established for these costs at March 31, 2009. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the U.S. Environmental Protection Agency s (the EPA) Spill Prevention, Control and Countermeasures (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 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 HOLP, 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 amounts have been recorded in our condensed consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

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

As of March 31, 2009 and December 31, 2008, an accrual on an undiscounted basis of $13.1 million and $13.3 million, respectively, was recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover 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 under the Pipeline Hazardous Materials Safety Administration (PHMSA), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule (the IMP Rule) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas . Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing, or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Through March 31, 2009, Transwestern did not incur any costs associated with the IMP Rule. For the three months ended March 31, 2009 and 2008, $3.5 million and $1.5 million, respectively, of capital costs and $3.3 million and $3.6 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. For the three months ended March 31, 2009 $0.2 million of capital costs and $0.1 million of operating and maintenance costs have been incurred for pipeline integrity costs for Transwestern. No capital costs or operating and maintenance costs were incurred for pipeline integrity costs for Transwestern for the three months ended March 31, 2008. 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.

15. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility in these prices, we utilize various exchange-traded and over-the-counter (OTC) commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the condensed consolidated balance sheets. We have a risk management policy that specifies the manner in which derivative financial instruments are employed and monitored in connection with underlying asset, liability and/or anticipated transactions. Furthermore, on a bi-weekly basis, management reviews the creditworthiness of the derivative counterparties to manage against the risk of default.

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 AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge s change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the condensed consolidated statement of operations.

We expect losses of $3.1 million related to commodity derivatives to be reclassified into earnings over the next twelve months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

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

Trading Activities

As of July 2008, we no longer engage in the trading of commodity derivative instruments that are not substantially offset by physical or other commodity derivative positions. As a result, we no longer have any material exposure to market risk from such activities. The derivative contracts that were previously entered into for trading purposes were recognized in the condensed consolidated balance sheet at fair value, and changes in the fair value of these derivative instruments are recognized in revenue in the condensed consolidated statements of operations on a net basis. There were no gains or losses associated with trading activities during the three months ended March 31, 2009. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net gains of approximately $0.4 million for the three months ended March 31, 2008.

The following table details the outstanding commodity-related derivatives:

March 31, 2009

	Commodity	Notional Volume	Maturity
Mark to Market Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	15,012,500	2009-2011
Swing Swaps IFERC (MMBtu)	Gas	(37,565,000)	2009-2010
Fixed Swaps/Futures (MMBtu)	Gas	(18,665,000)	2009-2011
Forwards/Swaps (Gallons)	Propane/Ethane	19,068,000	2009-2010
Cash Flow Hedging Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	687,500	2009
Fixed Swaps/Futures (MMBtu)	Gas	687,500	2009

December 31, 2008

	Commodity	Notional Volume	Maturity
Mark to Market Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	15,720,000	2009-2011
Swing Swaps IFERC (MMBtu)	Gas	(58,045,000)	2009
Fixed Swaps/Futures (MMBtu)	Gas	(20,880,000)	2009-2010
Forwards/Swaps (Gallons)	Propane	47,313,002	2009
Cash Flow Hedging Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	(9,085,000)	2009
Fixed Swaps/Futures (MMBtu)	Gas	(9,085,000)	2009

Interest Rate Risk

We are exposed to market risk for changes in interest rates. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps, certain of which are accounted for as cash flow hedges.

We have the following interest rate swaps outstanding as of March 31, 2009:

- Forward starting swaps with notional amounts of $100.0 million and $150.0 million to pay fixed rates of 2.96% and 2.97%, respectively, and receive floating rates with terms of August 2009 and September 2009, respectively; and

- Forward starting swaps with a notional amount of $500.0 million to pay a fixed rate of 3.99% and receive a floating rate with a term of December 2009.

Subsequent to March 31, 2009, the Partnership terminated forward starting swaps with notional amounts of $100.0 million and $150.0 million for an insignificant amount.

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Derivative Summary

The following table provides a balance sheet overview of the Partnership s derivative assets and liabilities as of March 31, 2009 and December 31, 2008:

		Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	March 31, 2009	December 31, 2008	March 31, 2009	December 31, 2008
Derivatives designated as hedging instruments under SFAS 133:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$	$ 10,665	$ (2,388)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	32	918	(45)	(119)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities				
Total derivatives designated as hedging instruments		**$ 32**	**$ 11,583**	**$ (2,433)**	**$ (1,623)**
Derivatives not designated as hedging instruments under SFAS 133:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	211,402	432,614	(220,100)	(335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	4,908	17,244	(11,162)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	1,004		(37,770)	(51,643)
Total derivatives not designated as hedging instruments		**$ 217,314**	**$ 449,858**	**$ (269,032)**	**$ (443,282)**
Total derivatives		**$ 217,346**	**$ 461,441**	**$ (271,465)**	**$ (444,905)**

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

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives. We exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendor in the condensed consolidated balance sheets. The Partnership had net deposits with counterparties of $38.5 million and $78.2 million as of March 31, 2009 and December 31, 2008, respectively, reflected as deposits paid to vendors in our condensed consolidated balance sheets.

The following table details the effect of the Partnership s derivative assets and liabilities in the condensed consolidated statements of operations for the periods presented:

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective	Change in Value Recognized in OCI on Derivatives (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives

	and Ineffective Portion)	Three Months Ended March 31,		Three Months Ended March 31,		Three Months Ended March 31,	
		2009	2008	2009	2008	2009	2008
Derivatives in SFAS 133 cash flow hedging relationships:							
Commodity Derivatives	Cost of Products Sold	$ (1,386)	$ (6,261)	$ 10,477	$ 30,871	$	$ (8,320)
Interest Rate Swap Derivatives	Interest Expense			72	285		
Total		$ (1,386)	$ (6,261)	$ 10,549	$ 31,156	$	$ (8,320)

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	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives Three Months Ended March 31, 2009	2008
Derivatives not designated as hedging instruments under SFAS 133:			
Commodity Derivatives	Cost of Products Sold	$ 51,437	$ (44,845)
Trading Commodity Derivatives	Revenue		(716)
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate Derivatives	13,726	(600)
Total		$ 65,163	$ (46,161)

Credit Risk

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

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

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our condensed consolidated balance sheet and recognized in net income or other comprehensive income.

16. RELATED PARTY TRANSACTIONS:

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

		Three Months Ended March 31, 2009		2008	
Enterprise Transactions	**Product**	**Volumes (in thousands)**	**Dollars**	**Volumes (in thousands)**	**Dollars**
Propane Operations -					
Sales	Propane (Gallons)	9,030	$ 6,282	9,030	$ 13,190
	Derivative Activity				1,923
Purchases	Propane (Gallons)	114,597	$ 101,926	141,122	$ 199,526
	Derivative Activity		33,292		
Natural Gas Operations -					
Sales	NGLs (Gallons)	115,855	$ 66,185	7,386	$ 10,159
	Natural Gas (MMBtu)	1,255	9,689	1,602	12,861
	Fees		(1,391)		1,672
Purchases	Natural Gas Imbalances (MMBtu)	1,521	$ 1,058	794	$ (4,688)
	Natural Gas (MMBtu)	2,702	12,548	2,409	19,772
	Fees		52		255

Accounts receivable from and accounts payable to related companies as of March 31, 2009 and December 31, 2008 relate primarily to activities in the normal course of business.

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Titan purchases substantially all of its propane requirements from Enterprise pursuant to an agreement that expires in 2010. As of March 31, 2009 and December 31, 2008, Titan had forward mark to market derivatives for approximately 18.6 million and 45.2 million gallons of propane at a fair value liability of $6.4 million and $40.1 million, respectively, with Enterprise.

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, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 25,429	$ 11,558
Accounts payable	780	567
Imbalance payable	(1,547)	(547)
Propane Operations:		
Accounts receivable	$ 1,932	$ 111
Accounts payable	16,358	33,308

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

	March 31, 2009	December 31, 2008
ETP GP	$ 152	$ 122
ETE	4,551	2,632
MEP	1,048	2,805
McReynolds Energy		202
Energy Transfer Technologies, Ltd.	17	16
Others	661	449
Total accounts receivable from related companies excluding Enterprise	$ 6,429	$ 6,226

The Chief Executive Officer (CEO) of our General Partner, Mr. Kelcy Warren, voluntarily determined that after 2007, his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards. We recorded non-cash 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, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

17. REPORTABLE SEGMENTS:

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

- natural gas operations:
  - intrastate transportation and storage
  - interstate transportation

midstream

retail propane and other retail propane related 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.

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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, interest expense, equity in earnings (losses) of affiliates 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 which is based on factors such as respective segments gross margins, employee costs and property and equipment.

The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month. The amounts allocated for the periods presented are as follows:

	Three Months Ended March 31, 2009	2008
Costs allocated from ETP to Operating Partnerships:		
Midstream and intrastate transportation and storage operations	$ 6,100	$ 3,897
Interstate operations	1,898	1,154
Retail propane and other retail propane related operations	4,654	2,550
Total	$ 12,652	$ 7,601
Costs allocated from Operating Partnerships to ETP:		
Midstream and intrastate transportation and storage operations	$ 3,885	$ 1,373
Retail propane and other retail propane related operations	445	600
Total	$ 4,330	$ 1,973

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

	Three Months Ended March 31, 2009	2008
Revenues:		
Intrastate transportation and storage:		
Revenues from external customers	$ 455,803	$ 965,661
Intersegment revenues	172,848	515,181
	628,651	1,480,842
Interstate transportation - revenues from external customers	61,349	55,416
Midstream:		
Revenues from external customers	594,803	986,770
Intersegment revenues	36,829	258,993
	631,632	1,245,763
Retail propane and other retail propane related - revenues from external customers	515,912	625,715
All other - revenues from external customers	2,233	5,809
Eliminations	(209,677)	(774,174)

Total revenues	$ 1,630,100	$ 2,639,371
Cost of products sold:		
Intrastate transportation and storage	$ 382,614	$ 1,200,473
Midstream	559,176	1,150,969
Retail propane and other retail propane related	225,105	397,730
All other	1,921	4,720
Eliminations	(209,677)	(774,174)
Total cost of products sold	$ 959,139	$ 1,979,718

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Depreciation and amortization:		
Intrastate transportation and storage	$ 25,033	$ 16,452
Interstate transportation	10,659	9,300
Midstream	16,510	13,846
Retail propane and other retail propane related	20,272	19,086
All other	129	144
Total depreciation and amortization	$ 72,603	$ 58,828
Operating income (loss):		
Intrastate transportation and storage	$ 143,715	$ 187,848
Interstate transportation	28,195	29,226
Midstream	25,139	52,386
Retail propane and other retail propane related	164,069	106,955
All other	(766)	(5)
Selling general and administrative expenses not allocated to segments	501	(2,924)
Total operating income	$ 360,853	$ 373,486
Other items not allocated by segment:		
Interest expense, net of interest capitalized	$ (82,045)	$ (55,549)
Equity in earnings of affiliates	497	74
Loss on disposal of assets	(426)	(1,451)
Gains (losses) on non-hedged interest rate derivatives	13,726	(600)
Allowance for equity funds used during construction	20,427	9,888
Other income, net	1,067	8,349
Income tax expense	(6,932)	(5,862)
	(53,686)	(45,151)
Net income	$ 307,167	$ 328,335

	As of March 31, 2009	As of December 31, 2008
Total assets:		
Intrastate transportation and storage	$ 4,523,023	$ 4,642,430
Interstate transportation	2,644,091	2,487,078
Midstream	1,522,120	1,537,972
Retail propane and other retail propane related	1,763,450	1,810,953
All other	146,935	149,056
Total	$ 10,599,619	$ 10,627,489

	Three Months Ended March 31, 2009	2008
Additions to Property, Plant and Equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 120,299	$ 158,464
Interstate transportation	41,327	202,357
Midstream	27,133	70,293
Retail propane and other retail propane related	17,242	48,410
All other	1,576	485

Total	$ 207,577	$ 480,009

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

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2008 filed with the Securities and Exchange Commission (SEC) on March 2, 2009. Our Management s Discussion and Analysis includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Item 1A. Risk Factors included in this report and in our Annual Report for the year ended December 31, 2008.

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 intrastate transportation and storage businesses (including transportation, gathering, compression, treating, processing, storage and marketing) and our propane business through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain additional businesses or assets. The actual amount of cash that we will have available for distribution will primarily depend on the amount of cash we generate from operations.

We have experienced substantial growth over the last five years through a combination of internal growth projects and strategic acquisitions.

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 Partners, 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, with assets totaling $3.87 billion in our natural gas operations and $848.2 million in our propane operations.

In addition to our acquisitions, our internal growth projects consist primarily of the construction of natural gas transmission pipelines, both intrastate and interstate. From September 1, 2003 through March 31, 2009, we made growth capital expenditures, excluding capital contributions made in connection with the Midcontinent Express pipeline (MEP) project, of approximately $4.6 billion, of which more than $3.9 billion was related to natural gas transmission pipelines, and we anticipate growth capital expenditures of an additional $595.0 million to $655.0 million during the last nine months of 2009, excluding capital contributions expected to be made in connection with the Midcontinent Express pipeline and Fayetteville Express pipeline (FEP) joint ventures, which are expected to total $545.0 million to $585.0 million for the same period. If Midcontinent Express pipeline obtains long-term financing in 2009 following completion of the base project, an additional capital contribution of $200.0 million to $250.0 million may be required.

Our principal operations are conducted in the following reportable segments (see Note 17 to our unaudited condensed consolidated financial statements):

- 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 based on the published market prices as of the first of the month and sold at market prices. The HPL System also generates revenue 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, in addition to generating revenue from fee-based contracts to reserve firm storage capacity.

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Interstate transportation - The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.

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.

Retail propane - Revenue is generated from the sale of propane and propane-related products and services.

Trends and Outlook

In light of the current conditions in the capital markets, and based on our projected growth capital expenditures and capital contributions to joint venture entities, we have taken significant steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate at $3.575 per Common Unit on an annualized basis since the second quarter of 2008, and continuing to appropriately manage operating and administrative costs. We have also recently increased the available capacity under the ETP Credit Facility by using approximately $225.9 million in net proceeds from our January 2009 Common Units offering and $993.6 million in net proceeds from a $1.0 billion senior notes offering in April 2009 to repay all outstanding borrowings under this facility. Additionally, in April 2009, we closed a 9,775,000 Common Units offering which provided us with net proceeds of approximately $352.4 million which we intend to use for funding capital expenditures and capital contributions to joint ventures related to pipeline construction projects. As of March 31, 2009, in addition to approximately $106.0 million of cash on hand, we had available capacity under the ETP Credit Facility of approximately $1.06 billion. On a pro forma basis, as of March 31, 2009, taking into account net proceeds of approximately $993.6 million from our April 2009 debt offering and net proceeds of approximately $352.4 million from our April 2009 Common Units offering, we had $1.94 billion of available capacity under the ETP Credit Facility and cash on hand of approximately $570.0 million. Based on our current estimates, we expect to utilize these resources, along with cash from operations, to fund our announced growth capital expenditures and working capital needs without having to access the capital markets until the latter half of 2010.

As noted above and despite the economic challenges and volatile capital markets, we have successfully raised $1.57 billion in proceeds from the recent debt and equity offerings since December 2008. We believe that the size and scope of our operations, our stable asset base and cash flow profile and our investment grade status will be significant positive factors in our efforts to obtain new debt or equity funding; however, there is no assurance that we will continue to be successful in obtaining financing under any of the alternatives discussed above if capital markets deteriorate further from current conditions. Furthermore, the terms, size and cost of any one of these financing alternatives could be less favorable and could be impacted by the timing and magnitude of our funding requirements, market conditions, and other uncertainties.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas and NGLs have fallen dramatically since July 2008. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our customers to announce plans to decrease drilling levels and, in some cases, to shut in or consider shutting in natural gas production from some producing wells.

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

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

Current economic conditions also indicate that many of our customers may encounter increased credit risk in the near term. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swaps where applicable, and to date have not had any significant credit losses associated with our transactions. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Results of Operations

Consolidated Results

	Three Months Ended March 31, 2009	2008	Change
Revenues	$ 1,630,100	$ 2,639,371	$ (1,009,271)
Cost of products sold	959,139	1,979,718	(1,020,579)
Gross margin	670,961	659,653	11,308
Operating expenses	181,773	178,970	2,803
Depreciation and amortization	72,603	58,828	13,775
Selling, general and administrative	55,732	48,369	7,363
Operating income	360,853	373,486	(12,633)
Interest expense, net of interest capitalized	(82,045)	(55,549)	(26,496)
Equity in earnings of affiliates	497	74	423
Loss on disposal of assets	(426)	(1,451)	1,025
Gains (losses) on non-hedged interest rate derivatives	13,726	(600)	14,326
Allowance for equity funds used during construction	20,427	9,888	10,539
Other income, net	1,067	8,349	(7,282)
Income tax expense	(6,932)	(5,862)	(1,070)
Net income	$ 307,167	$ 328,335	$ (21,168)

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

Interest Expense. Interest expense increased principally due to higher levels of borrowings which were used to finance growth capital expenditures in our intrastate transportation and storage and interstate transportation segments.

Gains (Losses) on Non-Hedged Interest Rate Derivatives. We recorded unrealized gains on our floating-to-fixed interest rate swaps as a result of increases in the relevant floating index rates during the three months ended March 31, 2009.

Allowance for Equity Funds Used During Construction. The increase in AFUDC on equity is due to the Phoenix project, which was completed in February 2009.

Other Income, Net. The decrease is primarily due to contributions in aid of construction which exceeded our project costs by $7.7 million for the three months ended March 31, 2008 compared to $0.1 million for the three months ended March 31, 2009.

Segment Operating Results

We evaluate segment performance based on operating income, 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 December 31, 2008 filed with the SEC on March 2, 2009.

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Operating income by segment is as follows:

	Three Months Ended March 31, 2009	2008	Change
Intrastate transportation and storage	$ 143,715	$ 187,848	$ (44,133)
Interstate transportation	28,195	29,226	(1,031)
Midstream	25,139	52,386	(27,247)
Retail propane and other retail propane related	164,069	106,955	57,114
Other	(766)	(5)	(761)
Unallocated selling, general and administrative expenses	501	(2,924)	3,425
Operating income	$ 360,853	$ 373,486	$ (12,633)

Unallocated Selling, General and Administrative Expenses. Selling, general and administrative expenses are allocated monthly to the Operating Partnerships using the Modified Massachusetts Formula Calculation. 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.

Intrastate Transportation and Storage

	Three Months Ended March 31, 2009	2008	Change
Natural gas MMBtu/d - transported	13,623,212	9,521,181	4,102,031
Natural gas MMBtu/d - sold	1,351,600	1,696,912	(345,312)
Revenues	$ 628,651	$ 1,480,842	$ (852,191)
Cost of products sold	382,614	1,200,473	(817,859)
Gross margin	246,037	280,369	(34,332)
Operating expenses	53,490	58,615	(5,125)
Depreciation and amortization	25,033	16,452	8,581
Selling, general and administrative	23,799	17,454	6,345
Segment operating income	$ 143,715	$ 187,848	$ (44,133)

Gross Margin. Intrastate transportation and storage gross margin decreased primarily due to the following factors:

Overall volumes on our transportation pipelines were higher due to the completion of several large diameter transportation pipeline expansion projects during 2008 due to the continued demand from our customers to transport natural gas through our intrastate pipeline system.

Transportation fees increased approximately $58.7 million due to increased volumes through our transportation pipelines as discussed above.

Our fuel retention revenues are directly impacted by changes in natural gas prices. Increases in natural gas prices increase our fuel retention revenues and decreases in natural gas prices decrease our fuel retention revenues. Natural gas prices for retained fuel decreased from a range of $8.00 to $9.00/MMBtu during the three months ended March 31, 2008 to $3.00 to $6.00/MMBtu during the three months ended March 31, 2009 resulting in a decrease to the retention margin of $44.3 million. This impact from changes in natural gas prices was offset by an increase in fuel retention revenue of $18.5 million resulting from the increased transportation volumes discussed above.

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We also experienced a net decrease in storage margin of $49.6 million. During the three months ended March 31, 2009, we withdrew approximately 11.3 Bcf of natural gas from our Bammel storage facility for a margin of $10.5 million, which included a $44.6 million non-cash lower of cost or market write-down of our natural gas inventory held at our Bammel facility. We recognized $52.8 million in margin during the three months ended March 31, 2008 from the sale of approximately 36.3 Bcf of natural gas.

In addition to the above factors, the lower natural gas prices reduced our gross margin by $6.3 million due to changes in the value of our imbalances. We also experienced a decrease in margin of $10.3 million from our HPL System due to less favorable market conditions during the three months ended March 31, 2009 compared to the same period last year.

Operating Expenses. Intrastate transportation and storage operating expenses decreased primarily due to a decrease in consumption expense of $16.4 million, which was principally affected by natural gas price changes between periods. Offsetting the decrease was an increase in ad valorem taxes of $9.8 million, increased pipeline maintenance expenses of $0.7 million, and increased operational overhead expenses of $0.7 million.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased primarily due to the completion of projects in connection with the continued expansion of our pipeline system.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased primarily due to increased allocated overhead expense of $4.2 million and increased professional fees of $4.0 million offset by a decrease in employee-related expenses of $1.5 million.

Interstate Transportation

	Three Months Ended March 31,		
	2009	2008	Change
Natural gas MMBtu/d - transported	1,747,560	1,619,358	128,202
Natural gas MMBtu/d - sold	20,600	11,084	9,516
Revenues	$ 61,349	$ 55,416	$ 5,933
Operating expenses	15,365	11,220	4,145
Depreciation and amortization	10,659	9,300	1,359
Selling, general and administrative	7,130	5,670	1,460
Segment operating income	$ 28,195	$ 29,226	$ (1,031)

Revenues. Interstate revenues increased primarily as a result of higher volumes transported by Transwestern following the completion of the San Juan lateral in July 2008 and the completion of the Phoenix project in February 2009.

Operating Expenses. Interstate operating expenses increased primarily due to higher electric usage required by the increased transportation volumes in addition to an increase in ad valorem taxes resulting from increased property values.

Depreciation and Amortization. Interstate depreciation and amortization expense increased primarily due to incremental depreciation associated with the completion of the Phoenix project.

Selling, General and Administrative Expenses. Interstate selling, general and administrative expenses increased primarily due to increased allocated overhead expenses.

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Midstream

	Three Months Ended March 31,		
	2009	2008	&nbs