GENESIS ENERGY LP
Form 10-Q
August 09, 2007

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 June 30, 2007

OR

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

Commission file number 1-12295

GENESIS ENERGY, L.P.
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdictions of incorporation or organization)*	**76-0513049** *(I.R.S. Employer Identification No.)*
500 Dallas, Suite 2500, Houston, TX *(Address of principal executive offices)*	**77002** *(Zip code)*
Registrant's telephone number, including area code:	**(713) 860-2500**

Securities registered pursuant to Section 12(g) of the Act:

NONE

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 _ü_ No ___

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

Large accelerated filer_____ Accelerated filer ü Non-accelerated filer_____

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2) of the Exchange Act).

Yes __ No _ü_

Indicate number of outstanding shares of each of the issuer's classes of common stock, as of the latest practicable date. Common Units outstanding as of August 6, 2007: 28,318,532

This report contains 40 pages

GENESIS ENERGY, L.P.

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PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

GENESIS ENERGY, L.P.
UNAUDITED CONSOLIDATED BALANCE SHEETS
(In thousands)

	June 30, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,832	$ 2,318
Accounts receivable:		
Trade	88,269	88,006
Related Party	1,216	1,100
Inventories	11,302	5,172
Net investment in direct financing leases, net of unearned income - current portion - related party	588	568
Other	1,876	2,828
Total current assets	107,083	99,992
FIXED ASSETS, at cost	70,801	70,382
Less: Accumulated depreciation	(40,908)	(39,066)
Net fixed assets	29,893	31,316
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	5,074	5,373
CO_2 ASSETS, net of amortization	31,351	33,404
JOINT VENTURES AND OTHER INVESTMENTS	17,619	18,226
OTHER ASSETS, net of amortization	12,306	2,776
TOTAL ASSETS	$ 203,326	$ 191,087
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 85,461	$ 85,063
Related party	1,864	1,629
Accrued liabilities	11,890	9,220
Total current liabilities	99,215	95,912
LONG-TERM DEBT	22,800	8,000
OTHER LONG-TERM LIABILITIES	963	991
MINORITY INTERESTS	521	522
COMMITMENTS AND CONTINGENCIES (Note 11)		
PARTNERS' CAPITAL:		
Common unitholders, 13,784 units issued and outstanding	78,166	83,884
General partner	1,661	1,778
Total partners' capital	79,827	85,662

TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	203,326	$	191,087

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

GENESIS ENERGY, L.P.
UNAUDITED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per unit amounts)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
REVENUES:				
Crude oil gathering and marketing:				
Unrelated parties (including revenues from buy/sell arrangements of $69,772 in the first quarter of 2006)	$ 190,293	$ 220,633	$ 363,136	$ 472,894
Related parties	442	195	878	379
Pipeline transportation, including natural gas sales:				
Unrelated parties	4,950	7,404	10,397	13,994
Related parties	1,385	1,217	2,726	2,397
CO_2 marketing revenues:				
Unrelated parties	3,295	3,239	6,162	6,626
Related parties	651	655	1,281	655
Total revenues	201,016	233,343	384,580	496,945
COSTS AND EXPENSES:				
Crude oil costs:				
Unrelated parties (including costs from buy/sell arrangements of $68,899 in the first quarter of 2006)	184,517	214,737	352,228	460,649
Related parties	18	24	29	1,484
Field operating costs	4,773	3,720	8,731	7,065
Pipeline transportation costs:				
Pipeline operating costs	2,996	2,477	5,681	4,746
Natural gas purchases	1,112	2,542	2,347	5,241
CO_2 marketing costs:				
Transportation costs - related party	1,236	1,153	2,334	2,174
Other costs	45	54	91	106
General and administrative	5,600	3,249	8,928	5,909
Depreciation and amortization	2,046	2,029	3,974	3,893
Net (gain) loss on disposal of surplus assets	(8)	1	(24)	(49)
Total costs and expenses	202,335	229,986	384,319	491,218
OPERATING (LOSS) INCOME	(1,319)	3,357	261	5,727
OTHER INCOME (EXPENSE):				
Equity in earnings of joint ventures	293	339	554	652
Interest income	34	30	78	108
Interest expense	(355)	(293)	(625)	(493)
Income tax (expense) benefit	(25)	11	(55)	11

(Loss) income before cumulative effect adjustment		(1,372)		3,444		213		6,005
Cumulative effect adjustment of adoption of new accounting principle		-		-		-		30
NET (LOSS) INCOME	$	(1,372)	$	3,444	$	213	$	6,035

GENESIS ENERGY, L.P.
UNAUDITED CONSOLIDATED STATEMENTS OF OPERATIONS - CONTINUED
(In thousands, except per unit amounts)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
NET (LOSS) INCOME PER COMMON UNIT - BASIC AND DILUTED:				
(Loss) income before cumulative effect adjustment	$ (0.09)	$ 0.24	$ 0.02	$ 0.43
Cumulative effect adjustment	-	-	-	-
NET (LOSS) INCOME	$ (0.09)	$ 0.24	$ 0.02	$ 0.43
Weighted average number of common units outstanding	13,784	13,784	13,784	13,784

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

GENESIS ENERGY, L.P.
UNAUDITED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

	Number of Common Units	Partners' Capital: Common Unitholders	Partners' Capital: General Partner	Total
Partners' capital, January 1, 2007	13,784	$ 83,884	$ 1,778	$ 85,662
Net income	-	209	4	213
Cash distributions	-	(5,927)	(121)	(6,048)
Partners' capital, June 30, 2007	13,784	$ 78,166	$ 1,661	$ 79,827

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

GENESIS ENERGY, L.P.
UNAUDITED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Six Months Ended June 30, 2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 213	$ 6,035
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation	1,921	1,857
Amortization of CO_2 contracts	2,053	2,036
Amortization of credit facility issuance costs	273	186
Amortization of unearned income on direct financing leases	(315)	(333)
Payments received under direct financing leases	594	594
Equity in earnings of investments in joint ventures	(554)	(652)
Distributions from joint ventures - return on investment	833	677
Gain on disposal of assets	(24)	(49)
Cumulative effect adjustment	-	(30)
Non-cash effect of stock appreciation rights plan	3,340	442
Other non-cash items	(992)	(332)
Changes in components of working capital -		
Accounts receivable	(379)	(18,411)
Inventories	(6,105)	(8,363)
Other current assets	952	1,196
Accounts payable	931	12,856
Accrued liabilities	314	747
Net cash provided by (used in) operating activities	3,055	(1,544)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to property and equipment	(718)	(480)
Distributions from joint ventures - return of investment	361	153
Investment in Sandhill Group, LLC	-	(5,037)
Investments, other	-	(513)
Proceeds from disposal of assets	195	67
Prepayment on purchase of Port Hudson assets	(8,100)	-
Other, net	(1,711)	(26)
Net cash used in investing activities	(9,973)	(5,836)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings, net	14,800	11,500

Other, net		(319)		(580)
Distributions to common unitholders		(5,927)		(4,825)
Distributions to general partner and minority interest owner		(122)		(98)
Net cash provided by financing activities		8,432		5,997
Net increase (decrease) in cash and cash equivalents		1,514		(1,383)
Cash and cash equivalents at beginning of period		2,318		3,099
Cash and cash equivalents at end of period	$	3,832	$	1,716

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

GENESIS ENERGY, L.P.
UNAUDITED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Basis of Presentation

Organization

We are a publicly traded Delaware limited partnership formed in December 1996. Our operations are conducted through our operating subsidiary, Genesis Crude Oil, L.P., and its subsidiaries. We are engaged in pipeline transportation of crude oil, and, to a lesser degree, natural gas and carbon dioxide (CO_2), crude oil gathering and marketing, and industrial gas activities, including wholesale marketing of CO_2 and processing of syngas through a joint venture. Our assets are located in the United States Gulf Coast area.

Our 2% general partner interest is held by Genesis Energy, Inc., a Delaware corporation and an indirect, wholly-owned subsidiary of Denbury Resources Inc. Denbury and its subsidiaries are hereafter referred to as Denbury. Our general partner also owns 7.4% of our outstanding common units and all of our incentive distribution rights. See Note 5.

Our general partner manages our operations and activities and employs our officers and personnel, who devote 100% of their efforts to our management.

On July 25, 2007, we acquired certain energy-related businesses of the Davison family of Ruston, Louisiana. See Note 14.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of June 30, 2007 and December 31, 2006 and our results of operations for the three and six months ended June 30, 2007 and 2006, our cash flows for the six months ended June 30, 2007 and 2006 and changes in partners' capital for the six months ended June 30, 2007. All intercompany transactions have been eliminated. The accompanying consolidated financial statements include Genesis Energy, L.P., its operating subsidiary and its subsidiary partnerships. Our general partner owns a 0.01% general partner interest in Genesis Crude Oil, L.P., which is reflected in our financial statements as a minority interest.

In 2005, we acquired a 50% interest in T&P Syngas Supply Company. In 2006, we acquired a 50% interest in Sandhill Group, LLC. These investments are accounted for by the equity method, as we exercise significant influence over their operating and financial policies. See Note 3.

No provision for federal income taxes related to our operations is included in the accompanying consolidated financial statements; as such income will be taxable directly to the partners holding partnership interests. In May 2006, the State of Texas enacted a law which will require us to pay a tax of 0.5% on our "margin," as defined in the law, beginning in 2008 based on our 2007 results. The "margin" to which the tax rate will be applied generally will be calculated on our revenues (for federal income tax purposes) less the cost of the products sold (for federal income tax purposes), in the State of Texas. See Note 13.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. The financial statements included herein have been prepared by us without audit pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, they reflect all adjustments (which consist solely of normal recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of the financial results for interim periods. Certain information and notes normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. However, we believe that the disclosures are adequate to make the information presented not misleading when read in conjunction with the information contained in the periodic reports we file with the SEC pursuant to the Securities Exchange Act of 1934, including the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006.

2. New Accounting Pronouncements

FASB Interpretation No. 48

In July 2006, the Financial Accounting Standards Board, or FASB, issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109", or FIN 48, which clarifies the accounting and disclosure for uncertainty in tax positions, as defined. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation was effective for us beginning January 1, 2007. The adoption of FIN 48 had no impact on our consolidated financial statements.

SFAS 157

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements", or SFAS 157. SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption encouraged. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. SFAS 157 may impact our balance sheet and statement of operations in many areas including the fair value measurement and allocation of the purchase price in business combinations and the fair value measurements for derivative instruments, impairment of assets, and asset retirement obligations. We are currently assessing the impact of SFAS 157 on our consolidated financial statements.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities", or SFAS 159. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of SFAS 159 on our consolidated financial statements.

EITF 07-4

In May 2007, the Emerging Issues Task Force of the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, *Earnings per Share*, to Master Limited Partnerships." This EITF considers the question of whether the incentive distribution rights ("IDRs") of a master limited partnership represent a participating security and should be considered in the calculation of earnings per unit. Under the "two class" method of computing earnings per unit, earnings are allocated to participating securities as if all of the earnings for the period had been distributed. The EITF also presents alternative methods for inclusion of IDRs in the computation of earnings per unit. The EITF did not reach a conclusion on this topic and will address it at its September 2007 meeting. Once a consensus is reached, it is expected to be effective for fiscal years beginning after December 15, 2007, and interim periods within those fiscal years. We will assess the impact of EITF 07-4 once a consensus is reached; however we would expect it to have an impact on our presentation of earnings per unit in the future. For additional information on our incentive distribution rights, see Note 5.

EITF 04-13

We enter into buy/sell arrangements that are accounted for on a gross basis in our statements of operations as revenues and costs of crude. These transactions are contractual arrangements that establish the terms of the purchase of a particular grade of crude oil at a specified location and the sale of a particular grade of crude oil at a different location at the same or at another specified date. These arrangements are detailed either jointly, in a single contract, or separately, in individual contracts that are entered into concurrently or in contemplation of one another with a single counterparty. Both transactions require physical delivery of the crude oil and the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk. In accordance with the provision of Emerging Issues Task Force Issue No. 04-13, “Accounting for Purchases and Sales of Inventory with the Same Counterparty,” we started reflecting these amounts of revenues and purchases as a net amount in our consolidated statements of operations beginning in the second quarter of 2006. Had this provision been in effect in the first quarter of 2006, our reported crude oil gathering and marketing revenues from unrelated parties for the six months ended June 30, 2006 would have been reduced by $70 million to $403 million. Our reported crude oil costs from unrelated parties for the six months ended June 30, 2006, would have been reduced by $69 million to $392 million. This change had no effect on operating income, net income or cash flows.

3. Joint Ventures and Other Investments

T&P Syngas Supply Company

We own a 50% interest in T&P Syngas Supply Company (“T&P Syngas”), a Delaware general partnership. Praxair Hydrogen Supply Inc. (“Praxair”) owns the remaining 50% partnership interest in T&P Syngas. T&P Syngas is a partnership that owns a syngas manufacturing facility located in Texas City, Texas. That facility processes natural gas to produce syngas (a combination of carbon monoxide and hydrogen) and high pressure steam. Praxair provides the raw materials to be processed and receives the syngas and steam produced by the facility under a long-term processing agreement. T&P Syngas receives a processing fee for its services. Praxair operates the facility.

We are accounting for our 50% ownership in T&P Syngas under the equity method of accounting as both partners have substantive participating rights. We reflect in our consolidated statements of operations our equity in T&P Syngas’ net income, net of the amortization of the excess of our investment over our share of partners’ capital of T&P Syngas. We paid $4.0 million more for our interest in T&P Syngas than our share of partners’ capital on the balance sheet of T&P Syngas at the date of the acquisition. This excess amount of the purchase price over the equity in T&P Syngas is being amortized using the straight-line method over the remaining useful life of the assets of T&P Syngas of eleven years. Our consolidated statements of operations for the three and six months ended June 30, 2007 included $402,000 and $811,000, respectively, as our share of the operating earnings of T&P Syngas, reduced by amortization of the excess purchase price of $88,000 and $176,000, respectively. Our consolidated statements of operations for the three and six months ended June 30, 2006 included $410,000 and $811,000, respectively, as our share of the operating earnings of T&P Syngas, reduced by amortization of the excess purchase price of $88,000 and $176,000, respectively. We received distributions from T&P Syngas of $1.1 million during the six months ended June 30, 2007.

The tables below reflect summarized financial information for T&P Syngas (in thousands):

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Revenues	$ 2,503	$ 2,510
Operating expenses and depreciation	(890)	(896)
Other income	9	7
Net income	$ 1,622	$ 1,621

	June 30, 2007	December 31, 2006
Current assets	$ 1,355	$ 1,355
Non-current assets	15,084	15,387
Total assets	$ 16,439	$ 16,742

Current liabilities	$	474	$	156
Non-current liabilties		173		165
Partners' capital		15,792		16,421
Total liabilites and partners' capital	$	16,439	$	16,742

Sandhill Group, LLC

On April 1, 2006, we acquired a 50% interest in Sandhill Group, LLC ("Sandhill"). At June 30, 2007, Magna Carta held the other 50% interest in Sandhill. Sandhill is a limited liability company that owns a CO_2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, beverage, chemical and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

We are accounting for our 50% ownership in Sandhill under the equity method of accounting as both partners have substantive participating rights. We reflect in our consolidated statements of operations our equity in Sandhill's net income, net of the amortization of the excess of our investment over our share of partners' capital of Sandhill that is not considered goodwill.

Our consolidated statements of operations for the three and six months ended June 30, 2007 included $48,000 and $57,000, respectively, as our share of the operating earnings of Sandhill, reduced by amortization of the excess purchase price of $69,000 and $138,000, respectively. Our consolidated statements of operations for the three and six months ended June 30, 2006 included $90,000, as our share of the operating earnings of Sandhill, reduced by amortization of the excess purchase price of $73,000. We received distributions from Sandhill of $60,000 during the six months ended June 30, 2007.

The tables below reflect summarized financial information for Sandhill (in thousands):

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Revenues	$ 5,069	$ 2,693
Operating expenses and depreciation	(4,956)	(2,513)
Other income	2	1
Net income	$ 115	$ 181

	June 30, 2007	December 31, 2006
Current assets	$ 1,367	$ 1,606
Non-current assets	6,325	6,592
Total assets	$ 7,692	$ 8,198
Current liabilities	$ 1,204	$ 1,463
Non-current liabilties	3,927	4,140
Partners' capital	2,561	2,595
Total liabilites and partners' capital	$ 7,692	$ 8,198

Other Projects

In 2006, we invested $1.0 million in a petroleum coke to ammonia project that is in the development stage. All of our investment may later be redeemed, with a return, or converted to equity after the project has obtained construction financing. We have committed to invest an additional $1.1 million in this project during the remainder of 2007. The funds we have invested will be used for project development activities, which include the negotiation of off-take agreements for the products and by-products of the plant to be constructed, securing permits and securing financing for the construction phase of the plant.

No events or changes in circumstances have occurred that indicate a significant adverse effect on the fair values of our investments at June 30, 2007, therefore our investments are included in our consolidated balance sheet at cost.

4. Debt

Our credit facility, with a maximum facility amount of $500 million, is with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The initial committed amount under our facility was $125 million, of which a maximum of $50 million could be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base is recalculated quarterly and at the time of material acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit from a credit standpoint based on our EBITDA (earnings before interest, taxes, depreciation and amortization), computed in accordance with the provisions of our credit facility.

The commitment amount can be increased up to the maximum facility amount for acquisitions or internal growth projects with approval of the lenders. Likewise, the borrowing base may be increased to the extent of pro forma additional EBITDA attributable to acquisitions with approval of the lenders. In connection with the Davison acquisition on July 25, 2007, we increased the committed amount under our credit facility to $500 million and the maximum for letters of credit to $100 million. Our borrowing base as of July 31, 2007 was $380 million. See Note 14.

At June 30, 2007, we had $22.8 million borrowed under our credit facility and we had $3.5 million in letters of credit outstanding. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of November 15, 2011. The total amount available for borrowings at June 30, 2007 was $53.0 million under our credit facility.

The key terms for rates under our credit facility are as follows:

· The interest rate on borrowings may be based on the prime rate or the LIBOR rate, at our option. The interest rate on prime rate loans can range from the prime rate plus 0.50% to the prime rate plus 1.875%. The interest rate for LIBOR-based loans can range from the LIBOR rate plus 1.50% to the LIBOR rate plus 2.875%. The rate is based on our leverage ratio as computed under the credit facility. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. As of July 31, 2007, our borrowing rates were the prime rate plus 1.25% or the LIBOR rate plus 2.25%.

· Letter of credit fees will range from 1.50% to 2.875% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At June 30, 2007, the rate was 1.50%. As of July 31, 2007, our letter of credit rate was 2.25%.

· We pay a commitment fee on the unused portion of the $125 million commitment. The commitment fee will range from 0.30% to 0.50% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At June 30, 2007, the commitment fee rate was 0.30%. As of July 31, 2007, our commitment rate was 0.50%.

Collateral under the credit facility consists of substantially all our assets. While in general, our general partner is jointly and severally liable for all of our obligations unless and except to the extent those obligations provide that they are non-recourse to our general partner, our credit facility expressly provides that it is non-recourse to our general partner (except to the extent of its pledge of its general partner interest in certain of our subsidiaries) and Denbury and its other subsidiaries.

Our credit facility contains customary covenants (affirmative, negative and financial) that limit the manner in which we may conduct our business. Our credit facility contains three primary financial covenants - a debt service coverage ratio, leverage ratio and funded indebtedness to capitalization ratio - that require us to achieve specific minimum financial metrics. In general, the debt service coverage ratio calculation compares EBITDA (as adjusted in accordance with the credit facility) to interest expense. The leverage ratio calculation compares our consolidated funded debt (as calculated in accordance with the credit facility) to EBITDA (as adjusted). The funded indebtedness ratio compares outstanding debt to the sum of our consolidated total funded debt plus our consolidated net worth.

Our credit facility includes provisions for the temporary adjustment of the required ratios following material acquisitions and with lender approval. If we meet these financial metrics and are not otherwise in default under our credit facility, we may make quarterly distributions; however the amount of such distributions may not exceed the sum of the distributable cash generated by us for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. At June 30, 2007, the excess of distributable cash over distributions under this provision of the credit facility was $18.4 million. For a summary of our non-financial covenants, please refer to our Annual Report on Form 10-K for the year ended December 31, 2006.

The carrying value of our debt under our credit facility approximates fair value primarily because interest rates fluctuate with prevailing market rates, and the applicable margin on outstanding borrowings reflect what we believe is market.

5. Partners' Capital and Distributions

Partners' Capital

Partner's capital at June 30, 2007 consists of 13,784,441 common units, including 1,019,441 units owned by our general partner, representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest), and a 2% general partner interest. On July 25, 2007, in connection with the Davison acquisition, we issued 13,459,209 common units to the entities owned and controlled by the Davison family. The units were issued at a contractual value of $20.8036 per unit. Additionally, our general partner exercised its right to maintain its right to maintain its proportionate share of our outstanding common units by purchasing 1,074,882 common units from us for $22.4 million cash, or $20.8036 per common unit. As required under our partnership agreement, our general partner also contributed approximately $6.2 million to maintain its capital account balance. See Note 14.

Our general partner owns all of our general partner interest, all of the 0.01% general partner interest in our operating partnership (which is reflected as a minority interest in the consolidated balance sheet at June 30, 2007) and operates our business.

Our partnership agreement authorizes our general partner to cause us to issue additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. As discussed in Note 4, our credit facility limits the amount of distributions we may pay in any quarter.

We paid or will pay the following distributions to the holders of our common units in 2006 and 2007:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	Total Amount
				(in thousands)	
Fourth quarter 2005	February 2006	$ 0.17	$ 2,343	$ 48	$ 2,391
First quarter 2006	May 2006	$ 0.18	$ 2,481	$ 51	$ 2,532
Second quarter 2006	August 2006	$ 0.19	$ 2,619	$ 53	$ 2,672
Third quarter 2006		$ 0.20	$ 2,757	$ 56	$ 2,813

	November 2006							
Fourth quarter 2006	February 2007	$	0.21	$	2,895	$	59	$ 2,954
First quarter 2007	May 2007	$	0.22	$	3,032	$	62	$ 3,094
Second quarter 2007	August 2007	$	0.23	$	3,170 (1)	$	65	$ 3,235 (1)

(1) The distribution payable on August 14, 2007 to holders of our common units is net of the amounts payable with respect to the common units issued in connection with the Davison transaction. The Davison unitholders and our general partner waived their right to receive such distributions, instead receiving purchase price adjustments with us. See Note 14.

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, the general partner is entitled to receive 13.3% of any distributions to holders of our common units in excess of $0.25 per unit, 23.5% of any distributions to holders of our common units in excess of $0.28 per unit and 49% of any distributions to holders of our common units in excess of $0.33 per unit without duplication. We have not paid any incentive distributions from our inception through June 30, 2007.

Net Income (Loss) Per Common Unit

The following table sets forth the computation of basic net income (loss) per common unit (in thousands, except per unit amounts).

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Numerators for basic and diluted net (loss) income per common unit:				
(Loss) income from continuing operations	$ (1,372)	$ 3,444	$ 213	$ 6,005
Less general partner 2% ownership	(27)	69	4	120
(Loss) income from continuing operations available for common unitholders	$ (1,345)	$ 3,375	$ 209	$ 5,885
Income from cumulative effect adjustment	$ -	$ -	$ -	$ 30
Less general partner 2% ownership	-	-	-	1
Income from cumulative effect adjustment available for common unitholders	$ -	$ -	$ -	$ 29
Denominator for basic and diluted per common unit - weighted average number of common units outstanding	13,784	13,784	13,784	13,784
Basic and diluted net (loss) income per common unit:				
(Loss) income from continuing operations	$ (0.09)	$ 0.24	$ 0.02	$ 0.43
Loss from cumulative effect adjustment	-	-	-	-
Net (loss) income	$ (0.09)	$ 0.24	$ 0.02	$ 0.43

6. Business Segment Information

Our operations consist of three operating segments: (1) Pipeline Transportation - interstate and intrastate crude oil, natural gas and CO_2 pipeline transportation; (2) Industrial Gases - the sale of CO_2 acquired under volumetric production payments to industrial customers and our investment in a syngas processing facility, and (3) Crude Oil Gathering and Marketing - the purchase and sale of crude oil at various points along the distribution chain. The tables below reflect all periods presented as though the current segment designations had existed, and include only continuing operations data.

We evaluate segment performance based on segment margin. We calculate segment margin as revenues less costs of sales and operation expenses, and we include income from investments in joint ventures. We do not deduct depreciation and amortization. All of our revenues are derived from, and all of our assets are located in the United States. The pipeline transportation segment information includes the revenue, segment margin and assets of the direct financing leases.

	Pipeline Transportation		Industrial Gases [a]		Crude Oil Gathering & Marketing		Total
			(in thousands)				
Three Months Ended June 30, 2007							
Segment margin excluding depreciation and amortization [b]	$	2,227	$	2,958	$	1,427	$ 6,612
Capital expenditures	$	337	$	-	$	42	$ 379
Maintenance capital expenditures	$	337	$	-	$	42	$ 379
Revenues:							
External customers	$	5,347	$	3,946	$	190,735	$ 200,028
Intersegment [d]		988		-		-	988
Total revenues of reportable segments	$	6,335	$	3,946	$	190,735	$ 201,016
Three Months Ended June 30, 2006							
Segment margin excluding depreciation and amortization [b]	$	3,602	$	3,026	$	2,347	$ 8,975
Capital expenditures	$	257	$	5,550	$	35	$ 5,842
Maintenance capital expenditures	$	126	$	-	$	35	$ 161
Revenues:							
External customers	$	6,828	$	3,894	$	220,828	$ 231,550
Intersegment [d]		1,793		-		-	1,793
Total revenues of reportable segments	$	8,621	$	3,894	$	220,828	$ 233,343
Six Months Ended June 30, 2007							
Segment margin excluding depreciation and amortization [b]	$	5,095	$	5,572	$	3,026	$ 13,693
Capital expenditures	$	559	$	-	$	135	$ 694
Maintenance capital expenditures	$	559	$	-	$	135	$ 694
Net fixed and other non-current assets [c]	$	38,964	$	48,970	$	8,309	$ 96,243
Revenues:							
External customers	$	11,007	$	7,443	$	364,014	$ 382,464
Intersegment [d]		2,116		-		-	2,116
Total revenues of reportable segments	$	13,123	$	7,443	$	364,014	$ 384,580

	Pipeline Transportation	Industrial Gases [a]	Crude Oil Gathering & Marketing	Total
		(in thousands)		
Six Months Ended June 30, 2006				
Segment margin excluding depreciation and amortization [b]	$ 6,404	$ 5,653	$ 4,075	$ 16,132
Capital expenditures	$ 423	$ 5,550	$ 156	$ 6,129
Maintenance capital expenditures	$ 224	$ -	$ 156	$ 380
Net fixed and other long-term assets [c]	$ 33,251	$ 54,101	$ 5,639	$ 92,991
Revenues:				
External customers	$ 13,926	$ 7,281	$ 473,273	$ 494,480
Intersegment [d]	2,465	-	-	2,465
Total revenues of reportable segments	$ 16,391	$ 7,281	$ 473,273	$ 496,945

a) Industrial gases includes our CO_2 marketing operations and the income from our investments in T&P Syngas Supply Company and Sandhill Group, LLC.

b) Segment margin was calculated as revenues less cost of sales and operations expense. It includes our share of the operating income of equity joint ventures. A reconciliation of segment margin to income before cumulative effect adjustment for the periods presented is as follows:

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in thousands)		*(in thousands)*	
Segment margin excluding depreciation and amortization	$ 6,612	$ 8,975	$ 13,693	$ 16,132
General and administrative expenses	(5,600)	(3,249)	(8,928)	(5,909)
Depreciation and amortization expense	(2,046)	(2,029)	(3,974)	(3,893)
Net gain (loss) on disposal of surplus assets	8	(1)	24	49
Interest expense, net	(321)	(263)	(547)	(385)
Income tax (expense) benefit	(25)	11	(55)	11
Income before cumulative effect adjustment	$ (1,372)	$ 3,444	$ 213	$ 6,005

c) Net fixed and other long-term assets are the measure used by management in evaluating the results of its operations on a segment basis. Current assets are not allocated to segments as the amounts are shared by the segments or are not meaningful in evaluating the success of the segment's operations.

d) Intersegment sales, in the opinion of management, were conducted on an arm’s length basis.

7. Transactions with Related Parties

Sales, purchases and other transactions with affiliated companies, in the opinion of management, are conducted under terms no more or less favorable than then-existing market conditions. The transactions with related parties were as follows:

	Six Months Ended June 30, 2007		2006	
	(in thousands)			
Truck transportation services provided to Denbury	$	878	$	379
Pipeline transportation services provided to Denbury	$	2,494	$	2,034
Payments received under direct financing leases from Denbury	$	594	$	594
Pipeline transportation income portion of direct financing lease fees with Denbury	$	318	$	333
Pipeline monitoring services provided to Denbury	$	60	$	30
Directors' fees paid to Denbury	$	74	$	60
CO_2 transportation services provided by Denbury	$	2,334	$	2,174
Crude oil purchases from Denbury	$	29	$	1,484
Operations, general and administrative services provided by our general partner	$	10,772	$	8,541
Distributions to our general partner on its limited partner units and general partner interest	$	559	$	455
Sales of CO_2 to Sandhill	$	1,281	$	655

Transportation Services

We provide truck transportation services to Denbury to move their crude oil from the wellhead to our Mississippi pipeline. Denbury pays us a fee for this trucking service that varies with the distance the crude oil is trucked. These fees are reflected in the statement of operations as gathering and marketing revenues.

Denbury is a shipper on our Mississippi pipeline. We also earned fees from Denbury under the direct financing lease arrangements for the Olive and Brookhaven crude oil pipelines and the Brookhaven CO_2 pipeline and recorded pipeline transportation income from these arrangements.

We also provide pipeline monitoring services to Denbury. This revenue is included in pipeline revenues in the statement of operations.

Directors' Fees

We paid Denbury for the services of each of four of Denbury's officers who serve as directors of our general partner, at an annual rate that is $10,000 per director less than the rate at which our independent directors were paid.

CO_2 Operations and Transportation

Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver CO_2 for us to our customers. In the first half of 2007, the inflation-adjusted transportation fee averaged $0.18 per Mcf.

Operations, General and Administrative Services

We do not directly employ any persons to manage or operate our business. Those functions are provided by our general partner. We reimburse the general partner for all direct and indirect costs of these services.

Amounts due to and from Related Parties

At both June 30, 2007 and December 31, 2006, we owed Denbury \$0.9 million and \$0.8 million, respectively, for purchases of crude oil and CO_2 transportation charges. Denbury owed us \$0.8 million and \$0.6 million for transportation services at June 30, 2007 and December 31, 2006, respectively. We owed our general partner \$1.0 million and \$0.9 million for administrative services at June 30, 2007 and December 31, 2006, respectively. At June 30, 2007 and December 31, 2006, Sandhill owed us \$0.4 million and \$0.5 million, respectively, for purchases of CO_2.

Financing

In general, our general partner is jointly and severally liable for all of our obligations unless and except to the extent those obligations provide that they are non-recourse to our general partner, although our credit facility expressly provides that it is non-recourse to owners of our equity interests, including our general partner (except to the extent of its pledge of its general partner interest in certain of our subsidiaries) and Denbury and its other subsidiaries.

We effectively guarantee our proportionate share (50%) of Sandhill's outstanding bank debt, which was \$4.2 million (\$2.1 million net to us) at June 30, 2007.

8. Major Customers and Credit Risk

Due to the nature of our crude oil operations, a disproportionate percentage of our trade receivables constitute obligations of oil companies. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of integrated and large independent energy companies with stable payment experience. The credit risk related to contracts which are traded on the NYMEX is limited due to the daily cash settlement procedures and other NYMEX requirements.

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

Shell Oil Company, Occidental Energy Marketing, Inc., and Calumet Specialty Products Partners, L.P. accounted for 24%, 19% and 12% of total revenues in the first half of 2007, respectively. Occidental Energy Marketing, Inc., Shell Oil Company and Calumet Specialty Products Partners, L.P. accounted for 21%, 17% and 11% of total revenues in the first half of 2006, respectively. The majority of the revenues from these three customers in both periods relate to our gathering and marketing operations.

9. Supplemental Cash Flow Information

We received interest payments of \$42,000 and \$124,000 for the six months ended June 30, 2007 and 2006, respectively. Payments of interest and commitment fees were \$204,000 and \$218,000 for the six months ended June 30, 2007 and 2006, respectively.

At June 30, 2007, we had incurred liabilities for fixed asset additions totaling \$0.1 million that had not been paid at the end of the second quarter, and, therefore, are not included in the caption "Additions to property and equipment" on the Consolidated Statements of Cash Flows.

10. Derivatives

Our market risk in the purchase and sale of crude oil contracts is the potential loss that can be caused by a change in the market value of the asset or commitment. In order to hedge our exposure to such market fluctuations, we may enter into various financial contracts, including futures, options and swaps. Historically, any contracts we have used to hedge market risk were less than one year in duration, although we have the flexibility to enter into arrangements with a longer term.

We may utilize crude oil futures contracts and other financial derivatives to reduce our exposure to unfavorable changes in crude oil prices. Every derivative instrument (including certain derivative instruments embedded in other contracts) must be recorded in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value must be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

We mark to fair value our derivative instruments at each period end, with changes in the fair value of derivatives that are not designated as hedges being recorded as unrealized gains or losses. Such unrealized gains or losses will change, based on prevailing market prices, at each balance sheet date prior to the period in which the transaction actually occurs. The effective portion of unrealized gains or losses on derivative transactions qualifying as cash flow hedges are reflected in other comprehensive income. Derivative transactions qualifying as fair value hedges are evaluated for hedge effectiveness and the resulting hedge ineffectiveness is recorded as a gain or loss in the consolidated statements of operations.

We review our contracts to determine if the contracts meet the definition of derivatives pursuant to SFAS 133. At June 30, 2007, we had futures contracts that were considered free-standing derivatives that are accounted for at fair value. The fair value of these contracts was determined based on the closing price for such contracts on June 30, 2007. We marked these contracts to fair value at June 30, 2007. During the three and six months ended June 30, 2007, we recorded losses of $80,000 and $19,000, respectively, related to derivative transactions, which is included in the consolidated statements of operations under the caption "Crude oil costs".

At June 30, 2007, we had futures contracts that qualified as derivatives and were formally documented and designated as fair value hedges of inventory. During the three and six months ended June 30, 2007, we recognized gains, due to hedge ineffectiveness, on the fair value hedge of inventory of approximately $81,000 and $456,000, respectively. These gains are included in the caption "Crude oil costs" in the consolidated statements of operations. The time value component of the derivative gain or loss excluded from the assessment of hedge effectiveness was not material.

The consolidated balance sheet at June 30, 2007 includes an increase in other current assets of $546,000 as a result of these derivative transactions. The consolidated balance sheet at December 31, 2006 included an increase in other current assets of $165,000 as a result of derivative transactions.

At June 30, 2006, we had futures contracts that were considered free-standing derivatives that are accounted for at fair value. The fair value of these contracts was determined based on the closing price for such contracts on June 30, 2006. We marked these contracts to fair value at June 30, 2006. During the six months ended June 30, 2006, we recorded losses of $177,000 related to derivative transactions, which is included in the consolidated statements of operations under the caption "Crude oil costs".

At June 30, 2006, we had futures contracts that qualified as derivatives and were formally documented and designated as fair value hedges of inventory. During the six months ended June 30, 2006, we recognized gains, due to hedge ineffectiveness, on the fair value hedge of inventory of approximately $57,000. These gains are included in the caption "Crude Oil Costs" in the consolidated statements of operations. The time value component of the derivative gain or loss excluded from the assessment of hedge effectiveness was not material.

We determined that the remainder of our derivative contracts qualified for the normal purchase and sale exemption and were designated and documented as such at June 30, 2007 and December 31, 2006.

11. Contingencies

Guarantees

We have guaranteed the payments by our operating partnership to the banks under the terms of our credit facility related to borrowings and letters of credit. To the extent liabilities exist under the letters of credit, such liabilities are included in the consolidated balance sheet. Borrowings at June 30, 2007 were $22.8 million and are reflected in the consolidated balance sheet. We have also guaranteed the payments by our operating partnership under the terms of our operating leases of tractors and trailers.

We guaranteed $1.2 million of residual value related to the leases of trailers from a lessor. We believe the likelihood we would be required to perform or otherwise incur any significant losses associated with this guarantee is remote.

We effectively guarantee our proportionate share (50%) of Sandhill's bank debt, which was $4.2 million ($2.1 million, net to us) at June 30, 2007. Sandhill makes principal payments totaling $0.6 million annually on that debt.

In general, we expect to incur expenditures in the future to comply with increasing levels of regulatory safety standards. While the total amount of increased expenditures cannot accurately be estimated at this time, we expect that our annual expenditures for integrity tests, repairs and improvements under regulations requiring assessment of the integrity of crude oil pipelines to average between $1.0 million and $1.5 million.

Pennzoil Litigation

We were named a defendant in a complaint filed on January 11, 2001, in the 125th District Court of Harris County, Texas, Cause No. 2001-01176. Pennzoil-Quaker State Company, or PQS, was seeking from us property damages, loss of use and business interruption suffered as a result of a fire and explosion that occurred at the Pennzoil Quaker State refinery in Shreveport, Louisiana, on January 18, 2000. PQS claimed the fire and explosion were caused, in part, by crude oil we sold to PQS that was contaminated with organic chlorides. In December 2003, our insurance carriers settled this litigation for $12.8 million.

PQS is also a defendant in five consolidated class action/mass tort actions brought by neighbors living in the vicinity of the PQS Shreveport, Louisiana refinery in the First Judicial District Court, Caddo Parish, Louisiana, Cause Nos. 455,647-A, 455,658-B, 455,655-A, 456,574-A, and 458,379-C. PQS has brought third party claims against us for indemnity with respect to the fire and explosion of January 18, 2000. We believe that the demand against us is without merit and intend to vigorously defend ourselves in this matter. We currently believe that this matter will not have a material financial effect on our financial position, results of operations, or cash flows.

Environmental

In 1992, Howell Crude Oil Company ("Howell") entered into a sublease with Koch Industries, Inc. ("Koch"), covering a one acre tract of land located in Santa Rosa County, Florida to operate a crude oil trucking station, known as Jay Station. The sublease provided that Howell would indemnify Koch for environmental contamination on the property under certain circumstances. Howell operated the Jay Station from 1992 until December of 1996 when this operation was sold to us by Howell. We operated the Jay Station as a crude oil trucking station until 2003. Koch has indicated that it has incurred certain investigative and/or other costs, for which Koch alleges some or all should be reimbursed by us, under the indemnification provisions of the sublease for environmental contamination on the site and surrounding areas. Koch has also alleged that we are responsible for future environmental obligations relating to the Jay Station.

Howell was acquired by Anadarko Petroleum Corporation ("Anadarko") in 2002. In 2005, we entered into a joint defense and cost allocation agreement with Anadarko. Under the terms of the joint allocation agreement, we agreed to reasonably cooperate with each other to address any liabilities or defense costs with respect to the Jay Station. Additionally under the joint allocation agreement, Anadarko will be responsible for sixty percent of the costs related to any liabilities or defense costs incurred with respect to contamination at the Jay Station.

We were formed in 1996 by the sale and contribution of assets from Howell and Basis Petroleum, Inc. ("Basis") Anadarko's liability with respect to the Jay Station is derived largely from contractual obligations entered into upon our formation. We believe that Basis has contractual obligations under the same formation agreements. We intend to seek recovery of Basis' share of potential liabilities and defense costs with respect to Jay Station.

We have developed a plan of remediation for affected soil and groundwater at Jay Station which has been approved by appropriate state regulatory agencies. We have accrued an estimate of our share of liability for this matter in the amount of $0.5 million. The time period over which our liability would be paid is uncertain and could be several years. This liability may decrease if indemnification and/or cost reimbursement is obtained by us for Basis' potential liabilities with respect to this matter. At this time, our estimate of potential obligations does not assume any specific amount contributed on behalf of the Basis obligations, although we believe that Basis is responsible for a significant part of these potential obligations.

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any releases of crude oil from our pipelines or other facilities, however no assurance can be made that such environmental releases may not substantially affect our business.

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations. We believe we are adequately insured for public liability and property damage to others and that our coverage is similar to other companies with operations similar to ours. No assurance can be made that we will be able to maintain adequate insurance in the future at premium rates that we consider reasonable.

As discussed in Note 3, we have committed to invest an additional $1.1 million in a potential petroleum coke to ammonia project.

We are subject to lawsuits in the normal course of business and examination by tax and other regulatory authorities. We do not expect such matters presently pending to have a material adverse effect on our financial position, results of operations or cash flows.

12. Stock Appreciation Rights Plan

At December 31, 2005, we had a recorded liability of $0.8 million for our stock appreciation rights plan, computed under the provisions of FASB Interpretation No. 28. We calculated the effect of adoption of SFAS 123(R) at January 1, 2006, and determined that our recorded liability at December 31, 2005 should be reduced by $30,000. This reduction is reflected as income from the cumulative effect of the adoption of a new accounting principle on our statement of operations in 2006. The adjustment of the liability to its fair value of $1.3 million at June 30, 2006, resulted in general and administrative expense of $0.3 million and $0.5 million for the three and six month periods ended June 30, 2006, respectively. The adjustment of the liability to its fair value at June 30, 2007, resulted in expense for the six months ended June 30, 2007 of $4.3 million, with $2.8 million, $0.8 million and $0.7 million included in general and administrative expenses, field operating costs and pipeline operating costs, respectively. For the three months ended June 30, 2007, the expense we recorded totaled $3.7 million, with $2.5 million, $0.6 million and $0.6 million included in general and administrative expenses, field operating costs and pipeline operating costs, respectively.

The following table reflects rights activity under our plan during the six months ended June 30, 2007:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual	Aggregate Intrinsic Value

				Remaining Term (Yrs)		
						(in thousands)
Outstanding at January 1, 2007	659,010	$	12.79			
Granted during 2007	43,138	$	29.12			
Exercised during 2007	(64,682)	$	9.42			
Forfeited or expired during 2007	(38,917)	$	14.77			
Outstanding at June 30, 2007	598,549	$	14.20	8.1	$	8,425
Exercisable at June 30, 2007	186,528	$	11.19	6.8	$	4,424

The weighted-average fair value at June 30, 2007 of rights granted during the first two quarters of 2007 was $8.93 per right. The total intrinsic value of rights exercised during the first six months of 2007 was $1.0 million, which was paid in cash to the participants.

At June 30, 2007, there was $3.3 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. This amount was calculated as the fair value at June 30, 2007 multiplied by those rights for which compensation cost has not been recognized, adjusted for estimated forfeitures. This unrecognized cost will be recalculated at each balance sheet until the rights are exercised, forfeited or expire. For the awards outstanding at June 30, 2007, the remaining cost will be recognized over a weighted average period of 1.1 years.

13. Income Taxes

In May 2006, the State of Texas enacted a law which will require us to pay a tax of 0.5% on our "margin," as defined in the law, beginning in 2008 based on our 2007 results. The "margin" to which the tax rate will be applied generally will be calculated as our revenues (for federal income tax purposes) less the cost of the products sold (for federal income tax purposes), in the State of Texas.

Under SFAS 109, taxes based on income like the Texas margin tax are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at the end of the period. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Temporary differences related to our inventory will affect the Texas margin tax, so we recorded a deferred tax asset in the amount of $11,000 upon enactment of the law in 2006. We believe that we will be able to utilize this deferred tax asset at June 30, 2007, and therefore have provided no valuation allowance against this deferred tax asset.

For the three and six months ended June 30, 2007, we have provided current tax expense in the amount of $25,000 and $55,000, respectively, as the estimate of the taxes that will be owed on our income for the period. The current liability we have accrued at June 30, 2007 is $55,000.

14. Subsequent Events

Davison Businesses Acquisition and Amendment to Credit Facility

On July 25, 2007, we completed the acquisition of the assets of businesses engaged in five energy- related segments from several entities owned and controlled by the Davison family of Ruston, Louisiana. The businesses acquired from the Davison family include:

- Refinery services business - The refinery service business operates as a third-party contractor to provide the service of processing sour gas streams to remove sulfur at more than a dozen refining operations, located primarily in Louisiana, Texas and Arkansas. This business is operated under the name of TDC, L.L.C.
- Petroleum products marketing business - The wholesale marketing of petroleum products business sells a variety of petroleum products to paper mills, utilities and other customers for use as fuels in their operations. This business has been operated under the name Davison Petroleum Products.
- Terminal business - The terminal business operates terminals for the storage and blending of refined petroleum products in north Louisiana and Mississippi. Each of the terminals is connected to multiple transportation modes. This business has been operated under the names Davison Terminal Services, Sunshine Oil and Storage and Red River Terminals.
- Trucking business - The trucking business operates a fleet of approximately 250 tractors and over 500 trailers under the name Davison Transport. The fleet, in addition to third-party carriage, supports the operations of the refinery

services, petroleum products marketing and terminal businesses.

- Fuel procurement business - The fuel procurement business provides fuel procurement and delivery logistics management services to wholesale and retail customers in more than 35 states nationwide. This business is operated under the name of Fuel Masters, LLC.

The total consideration for the transaction was $563 million, subject to adjustment. Approximately one-half of the consideration was paid with 13,459,209 of our common units, valued at $20.8036 per unit for purposes of the purchase agreement, totaling $280 million. The remainder of the purchase price of $283 million, adjusted for purchase price adjustments and estimated working capital of an additional $35.1 million was paid in cash borrowed under our credit agreement. For financial reporting purposes, the units issued will be valued at $24.52, the average value of our units at the time the purchase was announced.

Additionally, our general partner exercised its right to maintain its proportionate share of our outstanding common units by purchasing 1,074,882 common units from us for $22.4 million cash, or $20.8036 per common unit. As a result of this purchase, the general partner will continue to hold 7.4% of our outstanding common units. As required under our partnership agreement, our general partner also contributed approximately $6.2 million to maintain its capital account balance.

We also amended our existing credit facility. The amendment increased the committed amount under our facility from $125 million to $500 million, of which a maximum of $100 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The remaining significant terms of the credit agreement did not change.

Port Hudson Assets Acquisition

Effective July 1, 2007, we acquired the Port Hudson Crude Oil truck terminal, marine terminal, and marine dock of BP Pipelines (North America) Inc. (“Port Hudson”) for $8.1 million. The assets acquired in this transaction include docking facilities on the Mississippi River, 215,000 barrels of tankage, a pipeline and other related assets in East Baton Rouge Parish, Louisiana. The acquisition was funded with borrowings under our credit facility. We prepaid the purchase price for the acquisition on June 29, 2007, with the prepayment reflected in Other Assets on our consolidated balance sheet at June 30, 2007.

Distribution

On July 26, 2007, the Board of Directors of the general partner declared a cash distribution of $0.23 per unit for the quarter ended June 30, 2007. The distribution will be paid August 14, 2007 to our general partner and all common unitholders of record as of the close of business on August 6, 2007. The Davison unitholders and our general partner have waived receipt of their share of the distribution with respect to the units issued in connection with the Davison acquisition, instead receiving purchase price adjustments on transactions with us.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Included in Management's Discussion and Analysis are the following sections:

- Acquisitions and Related Activities in 2007
- Overview
- Results of Operations
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Other Matters
- New Accounting Pronouncements

Acquisitions and Related Activities in 2007

Davison Businesses Acquisition

On July 25, 2007, we completed the acquisition of certain assets of businesses engaged in five energy- related segments from several entities owned and controlled by the Davison family of Ruston, Louisiana. The Davison family has conducted energy-related transportation businesses in Ruston since 1937. The businesses acquired from the Davison family include:

- Refinery services business - The refinery service business operates as a third-party contractor to provide the service of processing sour gas streams to remove sulfur at more than a dozen refining operations, located primarily in Louisiana, Texas and Arkansas. This business is operated under the name of TDC, L.L.C.
- Petroleum products marketing business - The wholesale marketing of petroleum products business sells a variety of petroleum products to paper mills, utilities and other customers for use as fuels in their operations. This business has been operated under the name Davison Petroleum Products.
- Terminal business - The terminal business operates terminals for the storage and blending of refined petroleum products in north Louisiana and Mississippi. Each of the terminals is connected to multiple transportation modes. This business has been operated under the names Davison Terminal Services, Sunshine Oil and Storage and Red River Terminals.
- Trucking business - The trucking business operates a fleet of approximately 250 tractors and over 500 trailers under the name Davison Transport. The fleet, in addition to third-party carriage, supports the operations of the refinery services, petroleum products marketing and terminal businesses.
- Fuel procurement business - The fuel procurement business provides fuel procurement and delivery logistics management services to wholesale and retail customers in more than 35 states nationwide. This business is operated under the name of Fuel Masters, LLC.

The total consideration for the transaction was $563 million, subject to adjustment. Approximately one-half of the consideration was paid with 13,459,209 of our common units, issued at a contractual value of $20.8036 per unit for a total value of $280 million. The remainder of the purchase price of $283 million, adjusted for purchase price adjustments and estimated working capital of an additional $35.1 million was paid in cash borrowed under our credit facility.

Additionally, our general partner exercised its right to maintain its proportionate share of our outstanding common units by purchasing 1,074,882 common units from us for $22.4 million cash, or $20.8036 per common unit. As a result of this purchase, our general partner will continue to hold 7.4% of our outstanding common units. As required under our partnership agreement, our general partner also contributed approximately $6.2 million to maintain its capital account balance.

Pursuant to the Unitholder Agreement executed on July 25, 2007, the Davison unitholders have the right to designate up to two directors to the Board of Directors of our general partner, depending on their continued level of ownership in us. Until July 25, 2010, the Davison unitholders have the right to designate two directors to our general partner's Board of Directors. Thereafter, the Davison unitholders will have the right to designate (i) one director if they beneficially own at least 10% but less than 35% of our outstanding common units,or (ii) two directors if they beneficially own 35% of more of our outstanding common units. If their percentage ownership in our common units drops below 10% after July 25, 2010, the Davison unitholders have no rights to designate directors. On July 31, 2007, the Davison unitholders hold approximately 48% of our outstanding common units.

On July 25, 2007, the Davison unitholders designated James E. Davison and James E. Davison, Jr. as directors to the Board of Directors of our general partner.

In addition, we have agreed to call a special meeting of our unitholders as soon as practicable, but no later than 120 days from July 25, 2007 to propose an amendment to our partnership agreement that would allow the Davison unitholders to vote on all matters on which unitholders have a right to vote, other than matters related to the succession, election, removal, withdrawal, replacement or substitution of our general partner. Currently our partnership agreement does not allow any unitholder (including its affiliates) holding more than 20% of our outstanding units to vote.

Credit Agreement Amendment

As a result of the transaction with the Davison family, we also amended our existing credit facility. The amendment increased the committed amount under our facility from $125 million to $500 million, of which a maximum of $100 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement.

Drop-down Transactions

As Denbury has publicly stated, upon our achievement of certain goals, primarily our acquisition (by construction or purchase) of economic projects that are not related to Denbury’s operations, Denbury will undertake to “drop-down” certain midstream Denbury assets to us in an amount of $1.00 of Denbury assets for every $1.50 of non-Denbury-related acquisitions we complete. These “drop-down” transactions are currently thought most likely to consist of property sales combined with associated transportation or service arrangements or direct financing leases, or a combination of both. As a result of the transaction with the Davisons, we anticipate that during 2007, Denbury will enter into “drop-down” transactions with us involving their existing CO_2 pipelines, with a current estimated value of between $200 million and $250 million. These “drop-down” transactions would be subject to, among other things, negotiation of specific terms, the approval of the board of directors of both entities, and the receipt of fairness opinions by both companies, and are expected to occur during 2007. We would anticipate a similar transaction with Denbury for the new CO2 pipeline Denbury is constructing from its Jackson Dome to its Tinsley and Delhi Fields, once that pipeline is completed, currently estimated to be during 2008. If in future periods we are able to consummate with third parties additional acquisitions of sufficient size with acceptable economic returns, and subject to the same types of conditions, Denbury anticipates similar transactions with us for its proposed 280 to 300 mile CO_2 pipeline from South Louisiana to Hastings Field, located near Houston, Texas, probably during 2010. We expect to fund the transactions with Denbury with borrowings under our credit facility as well as other sources such as a public or private offering of debt or equity.

Port Hudson Assets Acquisition

Effective July 1, 2007, we acquired the Port Hudson Crude Oil truck terminal, marine terminal, and marine dock of BP Pipelines (North America) Inc. (“Port Hudson”) for $8.1 million. The assets acquired in this transaction include docking facilities on the Mississippi River, 215,000 barrels of tankage, a pipeline and other related assets in East Baton Rouge Parish, Louisiana. The acquisition was funded with borrowings under our credit facility. We made the payment for the acquisition on June 29, 2007, with the purchase price reflected in Other Assets on our consolidated balance sheet at June 30, 2007.

Overview

In the discussions that follow, we focus on two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before reserves. Our profitability depends to a significant extent upon our ability to maximize segment margin. Segment margin is calculated as revenues less cost of sales and operating expense, and does not include depreciation and amortization. Segment margin also includes our share of the equity in the operating income of our joint ventures. A reconciliation of segment margin to income from continuing operations is included in our segment disclosures in Note 6 to the consolidated financial statements. Available Cash before reserves is a non-GAAP liquidity measure calculated as net income with several adjustments, the most significant of which are the elimination of gains and losses on asset sales, except those from the sale of surplus assets, the addition of non-cash expenses such as depreciation, the replacement with the amount recognized as our equity in the income of joint ventures with the available cash generated from those ventures, and the subtraction of maintenance capital expenditures, which are expenditures to sustain existing cash flows but not to provide new sources of revenues. For additional information on Available Cash before reserves and a reconciliation of this measure to cash flows from operations, see “Liquidity and Capital Resources - Non-GAAP Financial Measure” below.

We conduct our business through three segments - pipeline transportation, industrial gases and crude oil gathering and marketing. We have a diverse portfolio of customers and assets, including pipeline transportation of primarily crude oil and, to a lesser extent, natural gas and CO_2 in the Gulf Coast region of the United States. In conjunction with our crude oil pipeline transportation operations, we operate a crude oil gathering and marketing business, which helps ensure a base supply of crude oil for our pipelines. We also participate in industrial gas activities, including a CO_2 supply business, which is associated with the CO_2 tertiary oil recovery process being used in Mississippi by an affiliate of our general partner. We generate revenues by selling crude oil and industrial gases, by charging fees for the transportation of crude oil, natural gas and CO_2 on our pipelines, and, through our joint venture in T&P Syngas Supply Company, by charging fees for services to produce syngas for our customer from the customer’s raw materials. Our focus is on the margin we earn on these revenues, which is calculated by subtracting the costs of the crude oil and natural gas; the costs of transporting the crude oil, natural gas and CO_2 to the customer; and the costs of operating our assets. We also report our share of the earnings of our joint ventures, T&P Syngas, in which we acquired a 50% interest on April 1, 2005, and Sandhill Group, LLC, in which we acquired a 50% interest on April 1, 2006.

Our objective is to operate as a growth-oriented midstream MLP with a focus on increasing cash flow, earnings and return to holders of our common units by becoming one of the leading providers of pipeline transportation, crude oil gathering and marketing and industrial gas services in the regions in which we operate. As is evidenced by the discussion above under "*Acquisitions and Related Activities in 2007*", we are pursuing acquisitions and projects involving transportation, gathering, terminal or storage assets and related midstream businesses, some of which may be outside the scope of our historical operations. We are presently engaged in discussions with various parties regarding acquisitions of assets or businesses, but we can give no assurance that our efforts will be successful or that any acquisitions will be completed on terms favorable to us.

Increases in cash flow generally result in increases in Available Cash, which we distribute quarterly to holders of our common units and general partner. During the second quarter of 2007, we generated $3.9 million of Available Cash before Reserves, and distributed $3.2 million to holders of our common units and general partner. During the second quarter of 2007, cash provided by operations was $1.3 million.

In the second quarter of 2007, we incurred a net loss of $1.4 million, or $0.09 per common unit, with $3.7 million of that loss attributable to the expense we recorded for our stock appreciation rights plan. The increase in our common unit market price from March 31, 2007 to June 30, 2007 of $13.54, or 63%, increased the expense we recorded under our plan.

For the six months ended June 30, 2007, we generated net income of $0.2 million, or $0.02 per common unit. Total expense recorded for our stock appreciation rights plan for the six month period was $4.3 million.

We increased our cash distribution by $0.01 to $0.22 per unit for the first quarter of 2007 (which was paid in May 2007) and increased our cash distribution again to $0.23 per unit for the second quarter of 2007. This distribution will be paid in August 2007. This distribution represented a 21% increase from our distribution of $0.19 per unit for the second quarter of 2006.

The expense for our stock appreciation rights plan added $2.2 million to general and administrative costs, $0.6 million each to pipeline operating costs and to crude oil gathering field costs, for a total impact to net income of $3.4 million when compared to the second quarter of 2006. For the six-month period, our expense for the stock appreciation rights plan added $2.4 million to general and administrative costs, $0.7 million to pipeline operating costs and $0.8 million to crude oil gathering field costs, for a total of $3.9 million. Under the accounting method used to account for our stock appreciation rights, we determine the fair value of the rights at the end of each reporting period using a Black-Scholes valuation model and we recognize the change in fair value as an expense. This fair value is affected by several assumptions as well as by the volatility of the market price for our common units. We believe that the significant increase in our unit price over the last year (particularly in the second quarter) has been the most significant contributor to the increase in expense for this plan. This expense is a non-cash charge until the employees holding the rights choose to exercise them. See Note 12 of the Notes to Unaudited Consolidated Financial Statements for information on outstanding and exercisable rights.

Results of Operations

The contribution of each of our segments to total segment margin in the first quarters of 2007 and 2006 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)		*(in thousands)*	
Pipeline transportation	$ 2,227	$ 3,602	$ 5,095	$ 6,404
Industrial gases	2,958	3,026	5,572	5,653
Crude oil gathering and marketing	1,427	2,347	3,026	4,075
Total segment margin	$ 6,612	$ 8,975	$ 13,693	$ 16,132

Pipeline Transportation Operations

We operate three crude oil common carrier pipeline systems in a four-state area. We refer to these pipelines as our Mississippi System, Jay System and Texas System. Additionally, we operate a CO_2 pipeline in Mississippi to transport CO_2 from Denbury's main CO_2 pipeline to Brookhaven oil field. Denbury has the exclusive right to use this CO_2 pipeline. We also have several natural gas gathering systems.

Operating results for our pipeline transportation segment were as follows:

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in thousands)		*(in thousands)*	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$ 3,458	$ 3,534	$ 6,994	$ 6,867
Sales of crude oil pipeline loss allowance volumes	1,441	2,077	3,140	3,395
Revenues from direct financing leases of CO_2 pipelines	80	86	162	173
Tank rental reimbursements and other miscellaneous revenues	164	164	327	308
Total revenues from crude oil and CO_2 tariffs, including revenues from direct financing leases	5,143	5,861	10,623	10,743
Revenues from natural gas tariffs and sales	1,192	2,760	2,500	5,648
Natural gas purchases	(1,112)	(2,542)	(2,347)	(5,241)
Pipeline operating costs	(2,996)	(2,477)	(5,681)	(4,746)
Segment margin	$ 2,227	$ 3,602	$ 5,095	$ 6,404
Barrels per day on crude oil pipelines:				
Total	57,127	62,778	57,499	62,420
Mississippi System	20,496	16,990	19,929	16,701
Jay System	11,602	13,727	12,204	12,577
Texas System	25,029	32,061	25,366	33,142

Three Months Ended June 30, 2007 Compared with Three Months Ended June 30, 2006

Pipeline segment margin for the second quarter of 2007 declined $1.4 million as compared to the second quarter of 2006. Revenues from crude oil tariffs and related sources and sales of pipeline loss allowance volumes decreased a total of $0.7 million and pipeline operating costs increased $0.5 million. The remaining decrease was attributable to a decline in net segment margin from natural gas pipeline activities.

Crude oil tariff and direct financing lease revenues decreased $0.1 million primarily due to a decline in the volume on the Texas System. Volumes on that system decreased 7,032 barrels per day; however the impact on revenues was not very significant due to the relatively low tariffs on that system. Approximately 76% of the volume on that system is shipped on a tariff of $0.22 per barrel, with an increase effective June 1, 2007 to $0.31 per barrel. Volumes increased on our Mississippi System by 3,506 barrels per day, which has a much higher tariff than the Texas System, offsetting much of the impact of the volume decrease. On our Jay System volumes decreased by 2,125 barrels per day, primarily due to maintenance work by both us and one of the shippers during the second quarter.

The volume increase on the Mississippi System was due to increased volumes shipped on our pipeline by Denbury for which we receive a tariff. Denbury is the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi. Our Mississippi System is adjacent to several of Denbury's existing and prospective oil fields. As Denbury continues to acquire and develop old oil fields using CO_2 based tertiary recovery operations, we expect Denbury to add crude oil gathering and CO_2 supply infrastructure to those fields, which could create opportunities for us.

The Jay System in Florida/Alabama ships crude oil from fields with relatively short remaining production lives. Recent changes in the ownership of the more mature producing fields in the area surrounding our Jay System have led to interest in further development of these fields which may lead to increases in production. Additionally, new wells have been drilled in the area. This new production produces greater tariff revenue for us due to the greater distance that the crude oil is transported on the pipeline.

Our Texas System is dependent on the connecting carriers for supply, and on the two refineries for demand for our services. Volumes on the Texas System have declined as a result of changes in the supply available for the two refineries to acquire and ship on our pipeline. Volumes on the Texas System may continue to fluctuate as refiners on the Texas Gulf Coast compete for crude oil with other markets connected to TEPPCO’s pipeline systems.

Sales of pipeline loss allowance volumes decreased $0.6 million due to a decrease in volumetric gain volumes of approximately 8,000 barrels. These volumes are sold at crude oil market prices.

Historically, the largest operating costs in our crude oil pipeline segment have consisted of personnel costs, power costs, maintenance costs and costs of compliance with regulations. Some of these costs are not predictable, such as failures of equipment or power cost increases. We perform regular maintenance on our assets in an effort to keep them in good operational condition and to minimize cost increases. Costs in the second quarter of 2007 were higher than in the second quarter of 2006 by a total of $0.5 million, all of which can be attributed to expense for our stock appreciation rights plan that relates to our pipeline operations personnel. This expense increased by $0.6 million between the second quarters. Slightly offsetting this expense were reductions in many other categories of expenses.

Six Months Ended June 30, 2007 Compared with Six Months Ended June 30, 2006

For the six-month periods, pipeline segment margin decreased by $1.3 million. Higher pipeline operating costs accounted for $0.9 million of the increase, with $0.7 million of that increase due to stock appreciation rights plan expense. The remaining $0.2 million increase in costs related to integrity management testing and costs to tear down a tank on the Texas System to prepare the location for its replacement. Revenues from crude oil tariffs and related sources and sales of pipeline loss allowance volumes decreased a total of $0.1 million and net segment margin from natural gas pipeline activities decreased by $0.3 million. The natural gas pipeline activities were impacted by production difficulties of a producer attached to the system.

As in the second quarter periods, the decline in crude oil pipeline volumes in the six month periods of 4,921 barrels per day did not have a significant impact on tariff revenues, as it was attributable to the lower tariff Texas System and was partially offset by volumes increases on the higher tariff Mississippi System.

Industrial Gases Segment

Our industrial gases segment includes the results of our CO_2 sales to industrial customers and our share of the operating income of our 50% joint venture interests in T&P Syngas and Sandhill. Operating results from our industrial gases segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)		*(in thousands)*	
Revenues from CO_2 sales	$ 3,946	$ 3,894	$ 7,443	$ 7,281
CO_2 transportation and other costs	(1,281)	(1,207)	(2,425)	(2,280)
Equity in earnings of joint ventures	293	339	554	652
Segment margin	$ 2,958	$ 3,026	$ 5,572	$ 5,653

Volumes per day:				
CO_2 sales - Mcf	75,039	73,495	71,120	70,049

Three Months Ended June 30, 2007 Compared with Three Months Ended June 30, 2006

Segment margin from industrial gases activities was consistent between the two second quarter periods. This margin is derived from two sources - sales of CO_2 and our equity in the earnings of joint ventures.

CO_2 Sales

We supply CO_2 to industrial customers under seven long-term CO_2 sales contracts. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price.

Our industrial customers treat the CO_2 and transport it to their own customers. The primary industrial applications of CO_2 by these customers include beverage carbonation and food chilling and freezing. Based on historical data for 2004 through 2007, we can expect some seasonality in our sales of CO_2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. Volumes sold each quarter in 2006 and in the first half of 2007 were as follows:

	Sales Mcf per Day
First Quarter 2006	66,565
Second Quarter 2006	73,980
Third Quarter 2006	82,244
Fourth Quarter 2006	68,452
First Quarter 2007	67,158
Second Quarter 2007	75,039

Although CO_2 sales volumes increased 1% between the two periods, the volumes varied under contracts such that revenues only increased by $52,000. The increased volumes and the inflation adjustment to the rate we pay Denbury to transport the CO_2 in its pipeline to our customers resulted in greater CO_2 transportation costs in the second quarter of 2007 when compared to the 2006 quarter.

Joint Ventures

We own a 50% interest in two joint ventures engaged in industrial gases activities, T&P Syngas and Sandhill. T&P Syngas owns a facility located in Texas City, Texas that manufactures syngas (a combination of carbon monoxide and hydrogen) and high-pressure steam. Under that processing agreement, Praxair provides the raw materials to be processed and receives the syngas and steam produced by the facility. T&P Syngas receives a processing fee for its services. Our share of the operating income of T&P Syngas for the three months ended June 30, 2007 and 2006 was the same. During the second quarters of 2007 and 2006, T&P Syngas paid us distributions totaling $0.5 million and $0.6 million, respectively, attributable to the first quarters of the years.

Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, beverage, chemicals and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury. Our share of the operating income of Sandhill for the second quarters of 2007 and 2006 was $48,000 and $90,000, respectively, which we reduced by $69,000 for the amortization of excess purchase price.

Six Months Ended June 30, 2007 Compared with Six Months Ended June 30, 2006

As in the three month periods, segment margin from our industrial gases segment for the six-month periods was consistent, with a $0.1 million, or 1%, decrease, primarily attributable to our Sandhill joint venture.

Additional discussion of our joint ventures is included in Note 3 of the Notes to the Unaudited Consolidated Financial Statements.

Crude Oil Gathering and Marketing Operations

Operating results from continuing operations for our crude oil gathering and marketing segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)		*(in thousands)*	
Revenues	$ 190,735	$ 220,828	$ 364,014	$ 473,273
Crude oil costs	(184,535)	(214,761)	(352,257)	(462,133)
Field operating costs	(4,773)	(3,720)	(8,731)	(7,065)
Segment margin	$ 1,427	$ 2,347	$ 3,026	$ 4,075
Volumes per day:				
Crude oil total - barrels	32,429	35,372	32,931 (1)	40,303 (1)
Crude oil truck transported only - barrels	4,742	4,258	4,855	3,517

(1) For purposes of comparison, barrels per day before excluding buy/sell volumes was 43,381 for the 2007 period and 45,670 for the 2006 period.

Three Months Ended June 30, 2007 as Compared to Three Months Ended June 30, 2006

Gathering and marketing segment margins decreased $0.9 million for the three months ended June 30, 2007, as compared to the three months ended June 30, 2006. Revenues for this segment are derived from sales of crude oil and from the transportation by truck for a fee of crude oil volumes that we did not purchase, with costs for this segment relating to the purchase of the crude oil and the related aggregation and transportation costs.

We conduct certain crude oil aggregating operations, which involve purchasing, gathering, transporting by trucks and pipelines owned by us and trucks, pipelines and barges operated by others, and reselling, that (among other things) help ensure supply for our crude oil pipeline systems. Our profit for those services is derived from the difference between the price at which we re-sell crude oil less the price at which we purchase that crude oil, minus the associated costs of aggregation and any cost of supplying credit. The most substantial component of our aggregating costs relates to operating our fleet of leased trucks. Our crude oil gathering and marketing activities provide us with extensive expertise, knowledge base and skill sets that facilitate our ability to capitalize on regional opportunities which arise from time to time in our market areas. Usually this segment experiences limited commodity price risk because we generally make back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis.

The commodity prices (for purchases and sales) of crude oil do not necessarily bear a relationship to segment margin as those prices normally impact revenues and costs of sales by approximately equivalent amounts. Because period-to-period variations in revenues and costs of sales are not generally meaningful in analyzing the variation in segment margin for our gathering and marketing operations, these changes are not addressed in the following discussion.

Generally, as we purchase crude oil, we simultaneously establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases, on the one hand, and sales or future delivery obligations, on the other hand. We do not hold crude oil, futures contracts or other derivative products to speculate on crude oil price changes. When our positions become unbalanced such that we have inventory, we will use derivative instruments to hedge that inventory until such time as we can sell it into the market.

When the crude oil markets are in contango, (oil prices for future deliveries are higher than for current deliveries), we may store crude oil as inventory in our storage tanks that we have purchased at lower prices in the current month for delivery at higher prices in future months. When we purchase this inventory, we simultaneously enter into a contract to sell the inventory in the future period, either with a counterparty or in the crude oil futures market. The maximum storage available to us for use in this strategy is approximately 120,000 barrels, although maintenance activities on our pipelines impact the availability of this storage capacity. We generally will account for this inventory and the related derivative hedge as a fair value hedge in accordance with Statement of Financial Accounting Standards No. 133. See Note 10 of the Notes to the Unaudited Consolidated Financial Statements.

Most of our contracts for the purchase and sale of crude oil have components in the pricing provisions such that the price paid or received is adjusted for changes in the market price for crude oil. The pricing in the majority of our purchase contracts contain the market price component, a bonus that is not fixed, but instead is based on another market factor and a deduction to cover the cost of transporting the crude oil and to provide us with a margin. Contracts will sometimes also contain a grade differential which considers the chemical composition of the crude oil and its appeal to different customers. Typically the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

Volumes declined by 2,943 barrels per day, primarily as a result of competition and the elimination of contracts during the second quarter of 2006 that did not meet our targets for profitability. We were also impacted by fluctuations in the differentials between the qualities of crude oil. The overall effect of the change in volumes and differentials affected segment margin by $0.4 million.

Volumes that we transported for a fee, but did not purchase, increased by 484 barrels per day. Most of this increase in volume was attributable to transportation of Denbury’s production from their wellheads to our pipeline. The increase in the fees for these services was $0.5 million between the two second quarter periods.

The primary reason for the decrease in segment margin is an increase in field operating costs of $1.1 million when comparing the second quarter periods. Expense related to our stock appreciation rights plan increased by $0.6 million between the periods. Compensation costs to operate the trucks and manage our crude oil gathering operations increased $0.4 million, as a result of compensation increases and the use of contract personnel. Increased fuel costs to operate our fleet of trucks accounted for most of the remaining $0.1 million increase in costs.

Six Months Ended June 30, 2007 as Compared to Six Months Ended June 30, 2006

For the six month periods, gathering and marketing segment margins decreased $1.0 million to $3.0 million for the six months ended June 30, 2007. Marketing margins decreased $0.5 million but were offset by increased revenues from volumes transported for a fee totaling $1.1 million. Field operating costs increased $1.6 million for the many of the same reasons as in the quarterly periods.

On a like-kind basis, volumes decreased 2,289 barrels per day, or 5%. We eliminated contracts during the first quarter of 2006 that did not meet our targets for profitability and we were impacted by significant volatility between crude quality differentials between the periods, with the overall impact on margin of $1.1 million. The margins generated from the storage of crude oil inventory in the contango market were $0.6 million greater in the 2007 first six months than in the prior year.

The increase in field costs was attributable to increases in the costs of personnel to operate our trucks and manage the operations totaling $0.6 million, an increase in stock appreciation rights expense of $0.8 million, and increased fuel costs of $0.2 million.

Other Costs and Interest

General and administrative expenses. General and administrative expenses consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)		*(in thousands)*	
Expenses excluding effect of stock appreciation rights plan and bonus plan	$ 2,650	$ 2,299	$ 5,189	$ 4,464
Bonus plan expense	433	630	879	973
Stock appreciation rights plan expense	2,517	320	2,860	472
Total general and administrative expenses	$ 5,600	$ 3,249	$ 8,928	$ 5,909

Between the second quarter periods, general and administrative expenses increased by $2.4 million, with $2.2 million attributed to increased stock appreciation rights plan expense and the remaining $0.2 million to other costs. These other costs included employee compensation expenses and fees for legal and other consulting services, offset by a decrease in bonus plan expense.

For the six-month periods, the $3.0 million increase in general and administrative costs is also primarily attributable to $2.4 million of increased stock appreciation rights plan expense. The remaining increase is related to increased employee compensation expenses and legal and other consulting fees.

Depreciation, amortization and impairment expense was flat between 2006 and 2007 second quarters, and $0.1 million greater between the six-month periods. The increase in the six month periods relates primarily to amortization of our CO_2 assets due to the greater volumes sold.

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)		*(in thousands)*	
Interest expense, including commitment fees	$ 289	$ 218	$ 498	$ 343
Capitalized interest	-	(2)	(6)	(2)
Amortization of facility fees	66	77	133	152
Interest income	(34)	(30)	(78)	(108)
Net interest expense	$ 321	$ 263	$ 547	$ 385

During the second quarter of 2007, our average outstanding balance of debt was $2.2 million more than in the second quarter of 2006. Additionally, our average interest rate was 0.5% greater than in the 2006 period, resulting in $71,000 more interest expense. For the six month periods, our average outstanding balance of debt was $5.6 million greater than the prior year period, which when combined with an interest rate that was 0.5% greater resulted in $155,000 more interest expense.

Liquidity and Capital Resources

Capital Resources

Capital Resources/Sources of Cash

In the last 12 months, we have adopted a growth strategy that has dramatically increased our cash requirements. We now expect our capital resources to include equity and debt offerings (public and private) and other financing transactions. Accordingly, we expect to access the capital markets (equity and debt) from time to time to partially refinance our capital structure and to fund other needs including acquisitions. Our ability to satisfy future capital needs with respect to our growth strategy will depend on our ability to raise substantial amounts of additional capital, to utilize our current credit facility and to implement our growth strategy successfully.

In November 2006, we entered into a credit facility with a maximum facility amount of $500 million (replacing our $100 million facility). The initial committed amount under our facility was $125 million, of which a maximum of $50 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base under the facility at June 30, 2007 was approximately $79 million, and is recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit based on our EBITDA, computed in accordance with the provisions of our credit facility. We increased the committed amount under our facility to $500 million and the maximum amount for letters of credit to $100 in connection with the Davison transaction. As of July 31, 2007, the borrowing base was $380 million and our outstanding borrowings were $304 million.

The terms of our credit facility also effectively limit the amount of distributions that we may pay to our general partner and holders of common units. Such distributions may not exceed the sum of the distributable cash generated for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. See Note 4 of the Notes to the Unaudited Consolidated Financial Statements.

We financed the Davison acquisition with the issuance of 13,459,209 common units for a total contractual value of $280 million ($20.8036 per common unit) and cash, which we funded with borrowings under our credit facility and the issuance of 1,074,882 common units to our general partner. Our general partner exercised its right to maintain its proportionate ownership interest in our common units, by purchasing these units for $22.4 million or $20.8036 per common unit. Additionally, we received $6.2 million from the general partner to maintain its general partner capital account balance as required by our partnership agreement. Other acquisitions may be initially funded primarily with debt or equity or any combination thereof.

Uses of Cash

Our cash requirements include funding day-to-day operations, maintenance and expansion capital projects, debt service, refinancings and distributions on our common units and other equity interests. We expect to use cash flows from operating activities to fund cash distributions and maintenance capital expenditures needed to sustain existing operations. Future expansion capital - acquisitions or capital projects - will require funding through various financing arrangements, as more particularly described under “Liquidity and Capital Resources - Capital Resources/Sources of Cash” above.

Operating. Our operating cash flows are affected significantly by changes in items of working capital. We have had situations where other parties have prepaid for purchases or paid more than was due, resulting in fluctuations in one period as compared to the next until the party recovers the excess payment. The timing of capital expenditures and the related effect on our recorded liabilities also affects operating cash flows.

Our accounts receivable settle monthly and collection delays generally relate only to discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered. Of the $89.5 million aggregate receivables on our consolidated balance sheet at June 30, 2007, approximately $88.3 million, or 98.6%, were less than 30 days past the invoice date.

Investing. We utilized cash flows to make capital expenditures, primarily for pipeline improvements. We received distributions from our T&P Syngas joint venture that exceeded our share of the earnings of T&P Syngas of $0.4 million during the first six months of 2007. Additionally we paid $8.1 million for our acquisition of the Port Hudson assets on June 29, 2007, and received $0.2 million from the sale of surplus assets.

Financing. Net cash of $8.4 million was provided by financing activities. We borrowed $14.8 million under our credit facility. We paid distributions totaling $6.0 million to our limited partners and our general partner during the six month period, and expended $0.3 million on other financing activities.

Capital Expenditures. A summary of our capital expenditures in the six months ended June 30, 2007 and 2006 is as follows:

	Six Months Ended June 30,	
	2007	2006
	(in thousands)	
Maintenance capital expenditures:		
Mississippi pipeline systems	$ 67	$ 78
Jay pipeline system	78	79
Texas pipeline system	414	67
Crude oil gathering assets	112	85
Administrative and other assets	23	71
Total maintenance capital expenditures	694	380
Growth capital expenditures (including construction in progress and investments in joint ventures)		
Mississippi pipeline systems	-	199
Sandhill Group, LLC investment	-	5,037
Other investment projects	-	513
Total growth capital expenditures	-	5,749
Total capital expenditures	$ 694	$ 6,129

We have no commitments to make capital expenditures; however, we anticipate that our maintenance capital expenditures relating to our existing assets for 2007 will be approximately $3.5 million. These expenditures are expected to relate primarily to the replacement of a tank on the Texas System and replacement of a segment of our Jay System. Based on the information available to us at this time, we do not anticipate that future capital expenditures for compliance with regulatory requirements will be material.

As discussed under "*Acquisitions and Related Activities in 2007* " above, we closed on the transaction with the Davison family in the third quarter of 2007 and we are currently negotiating with Denbury regarding the acquisition of certain CO_2 pipeline assets before the end of 2007.

Distributions

We are required by our partnership agreement to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We have increased our distribution for each of the last eight quarters, including the distribution to be paid for the second quarter of 2007, as shown in the table below.

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	Total Amount
				(in thousands)	
Fourth quarter 2005	February 2006	$ 0.17	$ 2,343	$ 48	$ 2,391
First quarter 2006	May 2006	$ 0.18	$ 2,481	$ 51	$ 2,532
Second quarter 2006	August 2006	$ 0.19	$ 2,619	$ 53	$ 2,672
Third quarter 2006	November 2006	$ 0.20	$ 2,757	$ 56	$ 2,813
Fourth quarter 2006	February 2007	$ 0.21	$ 2,895	$ 59	$ 2,954
First quarter 2007	May 2007	$ 0.22	$ 3,032	$ 62	$ 3,094
Second quarter 2007	August 2007	$ 0.23	$ 3,170	$ 65	$ 3,235

See Note 5 of the Notes to the Unaudited Consolidated Financial Statements.

Available Cash before reserves for the three and six months ended June 30, 2007 is as follows (in thousands):

	Three Months Ended June 30, 2007	Six Months Ended June 30, 2007
Net income	$ (1,372)	$ 213
Depreciation and amortization	2,046	3,974
Cash received from direct financing leases not included in income	141	279
Effects of available cash generated by investments in joint ventures not included in income	186	485
Non-cash charges	3,050	3,333
Proceeds from disposals of surplus assets	179	195
Maintenance capital expenditures	(379)	(694)
Available Cash before reserves	$ 3,851	$ 7,785

We have reconciled Available Cash before reserves (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) for the three and six months ended June 30, 2007 below. For the three months and six months ended June 30, 2007, cash flows provided by operating activities were $1.3 million and $3.1 million, respectively.

Non-GAAP Financial Measure

This quarterly report includes the financial measure of Available Cash before reserves, which is a "non-GAAP" measure because it is not contemplated by or referenced in accounting principles generally accepted in the U.S., also referred to as GAAP. The accompanying schedule provides a reconciliation of this non-GAAP financial measure to its most directly comparable GAAP financial measure. Our non-GAAP financial measure should not be considered as an alternative to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants.

Available Cash before reserves, also referred to as discretionary cash flow, is commonly used as a supplemental financial measure by management and by external users of financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (1) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest cost and support our indebtedness; (3) our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing and capital structure; and (4) the viability of projects and the overall rates of return on alternative investment opportunities. Because Available Cash before reserves excludes some, but not all, items that affect net income or loss and because these measures may vary among other companies, the Available Cash before reserves data presented in this Quarterly Report on Form 10-Q may not be comparable to similarly titled measures of other companies. The GAAP measure most directly comparable to Available Cash before reserves is net cash provided by operating activities.

Available Cash before reserves is a liquidity measure used by our management to compare cash flows generated by us to the cash distribution paid to our limited partners and general partner. This is an important financial measure to our public unitholders since it is an indicator of our ability to provide a cash return on their investment. Specifically, this financial measure aids investors in determining whether or not we are generating cash flows at a level that can support a quarterly cash distribution to the partners. Lastly, Available Cash before reserves (also referred to as distributable cash flow) is the quantitative standard used throughout the investment community with respect to publicly-traded partnerships.

The reconciliation of Available Cash before reserves (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) for the three and six months ended June 30, 2007, is as follows (in thousands):

	Three Months Ended June 30, 2007	Six Months Ended June 30, 2007
Cash flows from operating activities	$ 1,318	$ 3,055
Adjustments to reconcile operating cash flows to Available Cash:		
Maintenance capital expenditures	(379)	(694)
Proceeds from sales of certain assets	179	195
Amortization of credit facility issuance fees	(137)	(273)
Effects of available cash generated by investments in joint ventures not included in cash flows from operating activities	70	206
Cash effects of exercises under SAR Plan	(588)	(995)
Other items affecting Available Cash	690	1,009
Net effect of changes in operating accounts not included in calculation of Available Cash	2,698	5,282
Available Cash before reserves	$ 3,851	$ 7,785

Commitments and Off-Balance-Sheet Arrangements

Contractual Obligation and Commercial Commitments

Our obligations that are not currently recorded on our balance sheet consist of our operating leases and crude oil purchase commitments. Neither the amounts nor the terms of these commitments or contingent obligations have changed significantly from the year-end 2006 amounts reflected in our Annual Report on Form 10-K. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations — "Commitments and Off-Balance Sheet Arrangements" contained in our 2006 Form 10-K for further information regarding our commitments and obligations.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under *Contractual Obligation and Commercial Commitments* above, nor do we have any debt or equity triggers based upon our unit or commodity prices.

New and Proposed Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2, "New Accounting Pronouncements" in the accompanying consolidated financial statements.

Forward Looking Statements

The statements in this Quarterly Report on Form 10-Q that are not historical information may be "forward looking statements" within the meaning of the various provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions and other such references are forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy" or "will" or th terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include:

- *demand for, the supply of, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids or "NGLs" in the United States, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;*
- *throughput levels and rates;*
- *changes in, or challenges to, our tariff rates;*
- *our ability to successfully identify and consummate strategic acquisitions, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;*
- *service interruptions in our liquids transportation systems, natural gas transportation systems or natural gas gathering and processing operations;*
- *shut-downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, natural gas or other products or to whom we sell such products;*
- *changes in laws or regulations to which we are subject;*

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our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of existing debt agreements that contain restrictive financial covenants;

· *loss of key personnel;*

· *the effects of competition, in particular, by other pipeline systems;*

· *hazards and operating risks that may not be covered fully by insurance;*

· *the condition of the capital markets in the United States;*

- *loss of key customers;*
- *the political and economic stability of the oil producing nations of the world; and*
- *general economic conditions, including rates of inflation and interest rates.*

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2006. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risks primarily related to volatility in crude oil prices and interest rates.

Our primary price risk relates to the effect of crude oil price fluctuations on our inventories and the fluctuations each month in grade and location differentials and their effect on future contractual commitments. We utilize NYMEX commodity based futures contracts and forward contracts to hedge our exposure to these market price fluctuations as needed. At June 30, 2007, we had entered into NYMEX future contracts that will settle through September 2007. These contracts either do not qualify for hedge accounting or are fair value hedges, therefore the fair value of these derivatives have received mark-to-market treatment in current earnings. This accounting treatment is discussed further under Note 2 “Summary of Significant Accounting Policies” of our Consolidated Financial Statements in our Annual Report on Form 10-K.

		Sell (Short) Contracts		Buy (Long) Contracts
Futures Contracts				
Contract volumes (1,000 bbls)		148		1
Weighted average price per bbl	$	67.00	$	70.68
Contract value (in thousands)	$	9,917		1
Mark-to-market change (in thousands)		546		-
Market settlement value (in thousands)	$	10,463	$	1

The table above presents notional amounts in barrels, the weighted average contract price, total contract amount and total fair value amount in U.S. dollars. Fair values were determined by using the notional amount in barrels multiplied by the June 30, 2007 quoted market prices on the NYMEX.

We are also exposed to market risks due to the floating interest rates on our credit facility. Our debt bears interest at the LIBOR Rate or Prime Rate plus the applicable margin. We do not hedge our interest rates. At June 30, 2007, we had $22.8 million of debt outstanding under our credit facility.

Item 4. Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. Our chief executive officer and chief financial officer, with the participation of our management, have evaluated our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q and have determined that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosures.

There were no changes during our last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I. Item 1. Note 11 to the Consolidated Financial Statements entitled “Contingencies”, which is incorporated herein by reference.

Item 1A. Risk Factors.

For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2006. In addition, we believe that the following additional and updated risks factors are relevant for the businesses that we acquired from the Davison family.

Fluctuations in commodity prices could adversely affect our business.

Oil, natural gas, other petroleum products, and CO_2 prices are volatile and could have an adverse effect on our profits and cash flow. Our operations are affected by price reductions in those commodities. Price reductions in those commodities can cause material long and short term reductions in the level of throughput, volumes and margins in our logistic and supply businesses. Price changes for sodium hydrosulfide (NaHS) and caustic soda affect the margins we achieve in our refinery services business acquired from the Davison family.

Prices for commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our refinery services operations are dependent upon the supply of caustic soda and the demand for NaHS, as well as the operations of the refiners for whom we process sour gas.

Caustic soda is a major component used in the provision of sour gas treatment services provided by us to refineries. NaHS, the resulting product from the refinery services we provide, is a vital ingredient in a number of industrial and consumer products and processes. Any decrease in the supply of caustic soda could affect our ability to provide sour gas treatment services to refiners and any decrease in the demand for NaHS by the parties to whom we sell the NaHS could adversely affect our business. The refineries' need for our sour gas services is also dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

Our sour gas treatment services are dependent on contracts with fourteen refineries.

If one or more of those customers experience financial difficulties or changes in their strategy for sulfur removal such that they do not need our services, our cash flows could be adversely affected and we cannot assure you that an unanticipated reduction in the need for our services might not occur.

Our operating results from trucking operations acquired from the Davison family may fluctuate and may be materially adversely affected by economic conditions and business factors unique to the trucking industry.

Our trucking business is dependent upon factors, many of which are beyond our control. Those factors include excess capacity in the trucking industry, difficulty in attracting and retaining qualified drivers, significant increases or fluctuations in fuel prices, fuel taxes, license and registration fees and insurance and claims costs, to the extent not offset by increases in freight rates. Our results of operations from our trucking operations also are affected by recessionary economic cycles and downturns in customers' business cycles. Economic and other conditions may adversely affect our trucking customers and their ability to pay for our services.

In the past, there have been shortages of drivers in the trucking industry and such shortages may occur in the future. Periodically, the trucking industry experiences substantial difficulty in attracting and retaining qualified drivers. If we are unable to continue to retain and attract drivers, we could be required to adjust our driver compensation package, let trucks sit idle or otherwise operate at a reduced level, which could adversely affect our operations and profitability.

Significant increases or rapid fluctuations in fuel prices are major issues for the transportation industry. Increases in fuel costs, to the extent not offset by rate per mile increases or fuel surcharges, have an adverse effect on our operations and profitability.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

See Note 4 and 14 of the Notes to the Unaudited Consolidated Financial Statements.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

(a) Exhibits.

31.1	Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
31.2	Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
32.1	Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

SIGNATURES

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

GENESIS ENERGY, L.P.
(A Delaware Limited Partnership)
By: GENESIS ENERGY, INC., as General Partner

Date: August 9, 2007

By: /s/ Ross A. Benavides
Ross A. Benavides
Chief Financial Officer