GENESIS ENERGY LP
Form 10-Q
August 08, 2008

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

Form 10-Q

S QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2008

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.

YesR No £

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

Large accelerated filer £ Accelerated filer R Non-accelerated filer £ Smaller reporting company £

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

Yes £ No R

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. Common Units outstanding as of August 8, 2008: 39,452,305

GENESIS ENERGY, L.P.

Form 10-Q

INDEX

PART I. FINANCIAL INFORMATION

-2-

Index

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

	June 30, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,187	$ 11,851
Accounts receivable - trade	229,357	178,658
Accounts receivable - related party	5,872	1,441
Inventories	18,783	15,988
Net investment in direct financing leases, net of unearned income - current portion - related party	3,639	609
Other	5,807	5,693
Total current assets	272,645	214,240
FIXED ASSETS, at cost	230,707	150,413
Less: Accumulated depreciation	(56,265)	(48,413)
Net fixed assets	174,442	102,000
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	180,567	4,764
CO2 ASSETS, net of amortization	26,700	28,916
JOINT VENTURES AND OTHER INVESTMENTS	19,687	18,448
INTANGIBLE ASSETS, net of amortization	187,828	211,050
GOODWILL	325,045	320,708
OTHER ASSETS, net of amortization	12,328	8,397
TOTAL ASSETS	$ 1,199,242	$ 908,523
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 195,427	$ 154,614
Accounts payable - related party	2,024	2,647
Accrued liabilities	23,332	17,537
Total current liabilities	220,783	174,798
LONG-TERM DEBT	319,000	80,000
DEFERRED TAX LIABILITIES	14,817	20,087
OTHER LONG-TERM LIABILITIES	1,290	1,264
MINORITY INTERESTS	574	570
COMMITMENTS AND CONTINGENCIES (Note 16)		
PARTNERS' CAPITAL:		
Common unitholders, 39,452 and 38,253 units, respectively, issued and outstanding	625,932	615,265
General partner	16,846	16,539
Total partners' capital	642,778	631,804

TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,199,242	$ 908,523

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

Index

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
REVENUES:				
Supply and logistics:				
Unrelated parties	$ 568,328	$ 190,293	$ 997,721	$ 363,136
Related parties	1,149	442	1,874	878
Refinery services	55,727	-	99,639	-
Pipeline transportation, including natural gas sales:				
Transportation services - unrelated parties	5,168	3,768	11,077	7,923
Transportation services - related parties	4,115	1,385	5,167	2,726
Natural gas sales revenues	1,603	1,182	2,927	2,474
CO2 marketing revenues:				
Unrelated parties	3,693	3,295	6,856	6,162
Related parties	757	651	1,464	1,281
Total revenues	640,540	201,016	1,126,725	384,580
COSTS AND EXPENSES:				
Supply and logistics costs:				
Product costs - unrelated parties	542,200	184,517	949,475	352,228
Product costs - related parties	-	18	-	29
Operating costs	17,785	4,773	34,367	8,731
Refinery services operating costs	38,111	-	68,435	-
Pipeline transportation costs:				
Pipeline transportation operating costs	2,490	2,996	4,846	5,681
Natural gas purchases	1,568	1,112	2,854	2,347
CO2 marketing costs:				
Transportation costs - related party	1,376	1,236	2,633	2,334
Other costs	15	45	30	91
General and administrative	9,166	5,600	17,690	8,928
Depreciation and amortization	16,721	2,046	33,510	3,974
Net loss (gain) on disposal of surplus assets	76	(8)	94	(24)
Total costs and expenses	629,508	202,335	1,113,934	384,319
OPERATING INCOME (LOSS)	11,032	(1,319)	12,791	261
Equity in (losses) earnings of joint ventures	(16)	293	162	554
Interest income	117	34	234	78
Interest expense	(2,156)	(355)	(3,942)	(625)
INCOME (LOSS) BEFORE INCOME TAXES AND MINORITY INTEREST	8,977	(1,347)	9,245	268
Income tax expense	(1,648)	(25)	(271)	(55)
Income (loss) before minority interest	7,329	(1,372)	8,974	213
Minority interest	(1)	-	(1)	-
NET INCOME (LOSS)	$ 7,328	$ (1,372)	$ 8,973	$ 213
NET INCOME (LOSS) PER COMMON UNIT BASIC AND DILUTED	$ 0.17	$ (0.09)	$ 0.21	$ 0.02

WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:				
BASIC	38,675	13,784	38,464	13,784
DILUTED	38,731	13,784	38,514	13,784

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

Index

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

	Number of Common Units	Partners' Capital		
		Common Unitholders	General Partner	Total
Partners' capital, January 1, 2008	38,253	$ 615,265	$ 16,539	$ 631,804
Net income	-	8,045	928	8,973
Cash contributions		-	510	510
Cash distributions	-	(22,378)	(1,131)	(23,509)
Issuance of units	1,199	25,000	-	25,000
Partners' capital, June 30, 2008	39,452	$ 625,932	$ 16,846	$ 642,778

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

Index

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 8,973	$ 213
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation and amortization	33,510	3,974
Amortization of credit facility issuance costs	535	273
Amortization of unearned income and initial direct costs on direct financing leases	(1,772)	(315)
Payments received under direct financing leases	594	594
Equity in earnings of investments in joint ventures	(162)	(554)
Distributions from joint ventures - return on investment	815	833
Loss (gain) on disposal of assets	94	(24)
Non-cash effects of unit-based compensation plans	(619)	3,340
Deferred and other tax liabilities	(926)	-
Other non-cash items	(112)	(992)
Changes in components of operating assets and liabilities -Accounts receivable	(57,689)	(379)
Inventories	(2,796)	(6,105)
Other current assets	(76)	952
Accounts payable	40,190	931
Accrued liabilities and taxes payable	2,137	314
Net cash provided by operating activities	22,696	3,055
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed assets	(9,543)	(718)
CO2 pipeline transactions and related costs	(228,833)	-
Distributions from joint ventures - return of investment	438	361
Investment in joint ventures and other investments	(2,210)	-
Proceeds from disposal of assets	426	195
Prepayment on purchase of Port Hudson assets	-	(8,100)
Other, net	(1,272)	(1,711)
Net cash used in investing activities	(240,994)	(9,973)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings	344,100	77,900
Bank repayments	(105,100)	(63,100)
Other, net	(367)	(319)
General partner contributions	510	
Distributions to common unitholders	(22,378)	(5,927)
Distributions to general partner interest	(1,131)	(122)
Net cash provided by financing activities	215,634	8,432
Net (decrease) increase in cash and cash equivalents	(2,664)	1,514
Cash and cash equivalents at beginning of period	11,851	2,318

Cash and cash equivalents at end of period	$	9,187	$	3,832

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

Index

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

1. Organization and Basis of Presentation

Organization

We are a growth-oriented limited partnership focused on the midstream segment of the oil and gas industry in the Gulf Coast area of the United States. We conduct our operations through our operating subsidiaries and joint ventures. We manage our businesses through four divisions:

- Pipeline transportation of crude oil, carbon dioxide (or CO2) and, to a lesser degree, natural gas;
- Refinery services involving processing of high sulfur (or "sour") gas streams for refineries to remove the sulfur, and sale of the related by-product, sodium hydrosulfide (or NaHS, commonly pronounced nash);
- Industrial gas activities, including wholesale marketing of CO2 and processing of syngas through a joint venture; and
- Supply and logistics services, which includes terminaling, blending, storing, marketing, and transporting by trucks of crude oil and petroleum products as well as dry goods.

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 and its affiliates also own 10.2% of our outstanding common units.

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

Basis of Consolidation and Presentation

The accompanying unaudited consolidated financial statements and related notes present our consolidated financial position as of June 30, 2008 and December 31, 2007 and our results of operations for the three and six months ended June 30, 2008 and 2007, our cash flows for the six months ended June 30, 2008 and 2007 and changes in partners' capital for the six months ended June 30, 2008. All intercompany transactions have been eliminated. The accompanying unaudited consolidated financial statements include Genesis Energy, L.P. and its operating subsidiaries, Genesis Crude Oil, L.P. and Genesis NEJD Holdings, LLC, and their subsidiaries. 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 July 2007, we acquired the energy-related businesses of the Davison family. The results of the operations of these businesses have been included in our consolidated financial statements since August 1, 2007.

We own a 50% interest in T&P Syngas Supply Company and 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 8.

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 consolidated 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 consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2007.

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

Except per Unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

2. Recent Accounting Developments

Implemented

SFAS 157

We adopted Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements" (SFAS 157), with respect to financial assets and financial liabilities that are regularly adjusted to fair value, as of January 1, 2008. SFAS 157 provides a common fair value hierarchy to follow in determining fair value measurements in the preparation of financial statements and expands disclosure requirements relating to how such measurements were developed. SFAS 157 does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements. On February 12, 2008 the Financial Accounting Standards Board (FASB) issued Staff Position No. 157-2, "Effective Date of FASB Statement No. 157" (FSP 157-2) which amends SFAS 157 to delay the effective date for all non-financial assets and non-financial liabilities, except for those that are recognized at fair value in the financial statements on a recurring basis. The partial adoption of SFAS 157 as described above had no material impact on us. We have not yet determined the impact, if any, that the second phase of the adoption of SFAS 157 in 2009 will have relating to its fair value measurements of non-financial assets and non-financial liabilities. See Note 18 for further information regarding fair-value measurements.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159). This statement became effective for us as of January 1, 2008. SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. We did not elect to utilize voluntary fair value measurements as permitted by the standard.

Pending

SFAS 141(R)

In December 2007, the FASB issued SFAS No. 141(R) "Business Combinations" (SFAS 141(R)). SFAS 141(R) replaces FASB Statement No. 141, "Business Combinations." This statement retains the purchase method of accounting used in business combinations but replaces SFAS 141 by establishing principles and requirements for the recognition and measurement of assets, liabilities and goodwill, including the requirement that most transaction costs and restructuring costs be charged to expense as incurred. In addition, the statement requires disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We will adopt SFAS 141(R) on January 1, 2009 for acquisitions on or after that date.

SFAS 160

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51” (SFAS 160). This statement establishes accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior literature. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent company. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e. elimination of the mezzanine “minority interest” category); (ii) elimination of minority interest expense as a line item on the statement of operations and, as a result, that net income be allocated between the parent and the noncontrolling interests on the face of the statement of operations; and (iii) enhanced disclosures regarding noncontrolling interests. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We will adopt SFAS 160 on January 1, 2009. We are assessing the impact of this statement on our financial statements and expect it to impact the presentation of the minority interest in Genesis Crude Oil, L.P. held by our general partner.

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

SFAS 161

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No.133” (SFAS 161). This Statement requires enhanced disclosures about our derivative and hedging activities. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We will adopt SFAS No. 161 beginning January 1, 2009. We are currently evaluating the impact, if any, that the standard will have on our consolidated financial statements.

EITF 07-4

In March 2008, the FASB ratified the consensus reached by the Emerging Issues Task Force (or EITF) of the FASB in issue EITF 07-4, “Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships.” Under this consensus, the computation of earnings per unit will be affected by the incentive distribution rights (“IDRs”) we are contractually obligated to distribute at the end of the current reporting period. In periods when earnings are in excess of cash distributions, we will reduce net income or loss for the current reporting period by the amount of available cash that will be distributed to our limited partners and general partner for its general partner interest and incentive distribution rights for the reporting period, and the remainder will be allocated to the limited partner and general partner in accordance with their ownership interests. When cash distributions exceed current-period earnings, net income or loss will be reduced (or increased) by cash distributions, and the resulting excess of distributions over earnings will be allocated to the general partner and limited partner based on their respective sharing of losses. EITF 07-4 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are currently evaluating the impact of EITF 07-4; however we expect it to have an impact on our presentation of earnings per unit beginning in 2009. For additional information on our incentive distribution rights, see Note 10.

FASB Staff Position No. 142-3

In April 2008, the FASB issued FASB Staff Position No. 142-3, “Determination of the Useful Life of Intangible Assets” (FSP 142-3). This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of an intangible asset under Statement of Financial Accounting Standards No. 142, “Goodwill and other Intangible Assets.” The purpose of this FSP is to develop consistency between the useful life assigned to intangible assets and the cash flows from those assets. FSP 142-3 is effective for fiscal years beginning after December 31, 2008. We are currently evaluating the impact, if any, that the standard will have on our consolidated financial statements.

3. Acquisitions

2008 Denbury Drop-Down Transactions

On May 30, 2008, we completed two “drop-down” transactions with Denbury Onshore LLC, (Denbury Onshore), a wholly-owned subsidiary of Denbury Resources Inc., the indirect owner of our general partner.

NEJD Pipeline System

We entered into a twenty-year financing lease transaction with Denbury Onshore and acquired certain security interests in Denbury’s North East Jackson Dome (NEJD) Pipeline System for which we paid $175 million. Under the terms of the agreement, Denbury Onshore will make quarterly rent payments beginning August 30, 2008. These quarterly rent payments are fixed at $5,166,943 per quarter or approximately $20.7 million per year during the lease term at an interest rate of 10.25%. At the end of the lease term, we will reassign to Denbury Onshore all of our interests in the NEJD Pipeline for a nominal payment.

The NEJD Pipeline System is a 183-mile, 20” CO_2 pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldson, Louisiana, currently being used by Denbury for its tertiary operations in southwest Mississippi. Denbury has the rights to exclusive use of the NEJD Pipeline System, will be responsible for all operations and maintenance on that system, and will bear and assume all obligations and liabilities with respect to that system. The NEJD transaction was funded with borrowings under our credit facility.

See additional discussion of this direct financing lease in Note 6.

Index

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

Free State Pipeline System

We purchased Denbury's Free State Pipeline for $75 million, consisting of $50 million in cash, which we borrowed under our credit facility, and $25 million in the form of 1,199,041 of our common units. The number of common units issued was based on the average closing price of our common units from May 28, 2008 through June 3, 2008.

The Free State Pipeline is an 86-mile, 20" pipeline that extends from Denbury's CO2 source fields at the Jackson Dome, near Jackson, Mississippi, to Denbury's oil fields in east Mississippi. We entered into a twenty-year transportation services agreement to deliver CO2 on the Free State pipeline for Denbury's use in its tertiary recovery operations. Under the terms of the transportation services agreement, we are responsible for owning, operating, maintaining and making improvements to that pipeline. Denbury has rights to exclusive use of that pipeline and is required to use that pipeline to supply CO2 to its current and certain of its other tertiary operations in east Mississippi. The transportation services agreement provides for a $100,000 per month minimum payment, which is accounted for as an operating lease, plus a tariff based on throughput. Denbury has two renewal options, each for five years on similar terms. Any sale by us of the Free State Pipeline and related assets or of our ownership interest in our subsidiary that holds such assets would be subject to a right of first refusal purchase option in favor of Denbury.

2007 Davison Businesses Acquisition

On July 25, 2007, we acquired five energy-related businesses from several entities owned and controlled by the Davison family of Ruston, Louisiana (the "Davison Acquisition") for total consideration of $623 million (including cash and common units), net of cash acquired and direct transaction costs totaling $8.9 million. The businesses include the operations that comprise our refinery services division, and other operations included in our supply and logistics division, which transport, store, procure, and market petroleum products and other bulk commodities. The assets acquired in this transaction provide us with opportunities to expand our services to energy companies in the areas in which we operate.

In connection with the finalization of our valuation procedures with respect to certain fixed assets acquired in the Davison Acquisition, we reallocated $3.3 million of the purchase price from fixed assets to goodwill. In addition, the purchase price was adjusted by $1.0 million during the first half of 2008 for differences in working capital and fixed assets acquired. See additional information on intangible assets and goodwill in Note 7.

2007 Port Hudson Assets Acquisition

Effective July 1, 2007, we paid $8.1 million for BP Pipelines (North America) Inc.'s Port Hudson crude oil truck terminal, marine terminal, and marine dock on the Mississippi River, which includes 215,000 barrels of tankage, a pipeline and other related assets in East Baton Rouge Parish, Louisiana. The purchase price was allocated to the assets acquired based on estimated fair values. See additional information on goodwill in Note 7.

4. Inventories

Inventories are valued at the lower of cost or market. The costs of inventories did not exceed market values at June 30, 2008 and December 31, 2007. The major components of inventories were as follows:

	June 30, 2008	December 31, 2007

Crude oil	$	5,016	$	3,710
Petroleum products		5,120		6,527
Caustic soda		2,749		1,998
NaHS		5,739		3,557
Other		159		196
Total inventories	$	18,783	$	15,988

Index

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

5. Fixed Assets and Asset Retirement Obligations

Fixed assets consisted of the following:

	June 30, 2008	December 31, 2007
Land, buildings and improvements	$ 12,417	$ 11,978
Pipelines and related assets	139,184	63,169
Machinery and equipment	22,303	25,097
Transportation equipment	32,908	32,906
Office equipment, furniture and fixtures	3,548	2,759
Construction in progress	8,626	7,102
Other	11,721	7,402
Subtotal	230,707	150,413
Accumulated depreciation	(56,265)	(48,413)
Total	$ 174,442	$ 102,000

Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with the removal of our oil, natural gas and CO2 pipelines, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The capitalized cost is depreciated over the useful life of the related asset. Accretion of the discount increases the liability and is recorded to expense.

The following table summarizes the changes in our asset retirement obligations for the six months ended June 30, 2008.

Asset retirement obligations as of December 31, 2007	$ 1,173
Accretion expense	43
Asset retirement obligations as of June 30, 2008	$ 1,216

At June 30, 2008, $0.1 million of our asset retirement obligation was classified in “Accrued liabilities” under current liabilities in our Unaudited Consolidated Balance Sheets. Certain of our unconsolidated affiliates have asset retirement obligations recorded at June 30, 2008 and December 31, 2007 relating to contractual agreements. These amounts are immaterial to our financial statements.

6. Direct Financing Leases

In the fourth quarter of 2004, we constructed two segments of crude oil pipeline and a CO2 pipeline segment to transport crude oil from and CO2 to producing fields operated by Denbury. Denbury pays us a minimum payment each month for the right to use these pipeline segments. Those arrangements have been accounted for as direct financing leases. As discussed in Note 3, we entered into a lease arrangement with Denbury related to the NEJD Pipeline in May 2008 that is being accounted for as a direct financing lease. Denbury will pay us a fixed payment of $5.2 million per quarter beginning in August 2008.

Index

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

The following table lists the components of the net investment in direct financing leases at June 30, 2008 and December 31, 2007 (in thousands):

	June 30, 2008	December 31, 2007
Total minimum lease payments to be received	$ 419,802	$ 7,039
Estimated residual values of leased property (unguaranteed)	1,287	1,287
Unamortized initial direct costs	2,637	
Less unearned income	(239,520)	(2,953)
Net investment in direct financing leases	$ 184,206	$ 5,373

At June 30, 2008, minimum lease payments to be received for the remainder of 2008 are $10.9 million. Minimum lease payments to be received for each of the five succeeding fiscal years are $21.9 million per year for 2009 through 2011, $21.8 million for 2012 and $21.3 million for 2013.

7. Intangible Assets and Goodwill

Intangible Assets

In connection with the Davison acquisition (See Note 3), we allocated a portion of the purchase price to intangible assets based on their fair values. The following table reflects the components of intangible assets being amortized at the dates indicated:

		June 30, 2008			December 31, 2007		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Refinery services customer relationships	3	$ 94,654	$ 17,698	$ 76,956	$ 94,654	$ 9,380	$ 85,274
Supply and logistics customer relationships	5	34,630	6,655	27,975	34,630	3,287	31,343
Refinery services supplier relationships	2	36,469	16,881	19,588	36,469	9,241	27,228
Refinery services licensing	6	38,678	4,697	33,981	38,678	2,218	36,460

agreements							
Supply and logistics trade name	7	17,988	1,995	15,993	17,988	930	17,058
Supply and logistics favorable lease	15	13,260	434	12,826	13,260	197	13,063
Other	3	722	213	509	721	97	624
Total	5	$ 236,401	$ 48,573	$ 187,828	$ 236,400	$ 25,350	$ 211,050

The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The trade name is the Davison name, which we retained the right to use in our operations. The favorable lease relates to a lease of a terminal facility in Shreveport, Louisiana.

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution to our cash flows of the customer and supplier relationships, licensing agreements and trade name intangible assets is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The favorable lease and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $11.6 million and $23.2 million for the three and six months ended June 30, 2008, respectively.

Index

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

Estimated amortization expense for each of the five subsequent fiscal years is expected to be as follows:

Year Ended December 31	Amortization Expense to be Recorded	
Remainder of 2008	$	23,143
2009	$	32,176
2010	$	25,575
2011	$	20,943
2012	$	17,511
2013	$	14,107

Goodwill

In connection with the Davison and Port Hudson acquisitions (see Note 3), the residual of the purchase price over the fair values of the net tangible and identifiable intangible assets acquired was allocated to goodwill. The carrying amount of goodwill by business segment at June 30, 2008 was $301.9 million to refinery services and $23.1 million to supply and logistics.

8. 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. We received distributions from T&P Syngas of $1.1 million during each of the six months ended June 30, 2008 and 2007.

Sandhill Group, LLC

We own a 50% interest in Sandhill Group, LLC ("Sandhill"). At June 30, 2008, Reliant Processing Ltd. held the other 50% interest in Sandhill. Sandhill 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. We received distributions from Sandhill of $124,000 and $60,000 during the six months ended June 30, 2008 and 2007, respectively.

Other Projects

We have invested $4.6 million in the Faustina Project, 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. The funds we have invested are being 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. We have recorded our investment in this debt security at cost and classified it as held-to-maturity, since we have the intent and ability to hold it until it is redeemed.

No events or changes in circumstances have occurred that indicate a significant adverse effect on the fair value of our investment at June 30, 2008, therefore our investment is included in our Unaudited Consolidated Balance Sheet at cost.

Index

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

9. Debt

Our credit facility, with a maximum facility amount of $500 million, of which $100 million can be used for letters of credit, is with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The maximum facility 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 borrowing base may be increased to the extent of pro forma additional EBITDA, (as defined in the credit agreement), attributable to acquisitions or internal growth projects with approval of the lenders. Our borrowing base as of June 30, 2008 was $447 million.

At June 30, 2008, we had $319 million borrowed under our credit facility and we had $8 million in letters of credit outstanding. Our debt increased at June 30, 2008 from the December 31, 2007 level as a result of funding our CO2 pipeline transactions with Denbury. 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, 2008 was $120 million under our credit facility. Effective with the submission to banks of our quarterly compliance certificate for the quarter ended June 30, 2008, our borrowing base will increase to the maximum facility amount of $500 million.

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. At June 30, 2008, our borrowing rates were the prime rate plus 0.50% or the LIBOR rate plus 1.50%.

- 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, 2008, our letter of credit rate was 1.50%.

- We pay a commitment fee on the unused portion of the $500 million maximum facility amount. 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, 2008, the commitment fee rate was 0.30%.

Collateral under the credit facility consists of substantially all our assets, excluding our security interest in the NEJD and our ownership interest in the Free State pipelines. While 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), as well as to 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, our debt service coverage ratio calculation compares EBITDA (as defined and adjusted in accordance with the credit facility) to interest expense. Our leverage ratio calculation compares our consolidated funded debt (as calculated in accordance with our credit facility) to EBITDA (as adjusted). Our funded indebtedness ratio compares outstanding debt to the sum of our consolidated total funded debt plus our consolidated net worth.

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

Financial Covenant	Requirement	Required Ratio through June 30, 2008	Actual Ratio as of June 30, 2008
Debt Service Coverage Ratio	Minimum	2.75 to 1.0	5.05 to 1.0
Leverage Ratio	Maximum	6.0 to 1.0	2.9 to 1.0
Funded Indebtedness Ratio	Maximum	0.8 to 1.0	0.3 to 1.0

Our credit facility includes provisions for the temporary adjustment of the required ratios following material acquisitions and with lender approval. The ratios in the table above are the required ratios for the period following a material acquisition. 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, 2008, the excess of distributable cash over distributions under this provision of the credit facility was $31.3 million.

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.

10. Partners' Capital and Distributions

Partners' Capital

Partner's capital at June 30, 2008 consists of 39,452,305 common units, including 4,028,096 units owned by our general partner and its affiliates, 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.

Our general partner owns all of our general partner interest, including incentive distribution rights, all of the 0.01% general partner interest in Genesis Crude Oil, L.P. (which is reflected as a minority interest in the Unaudited Consolidated Balance Sheet at June 30, 2008) 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 9, our credit facility limits the amount of distributions we may pay in any quarter.

Pursuant to our partnership agreement, our general partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds, in addition to its 2% general partner interest. The allocations of distributions between our common unitholders and our general partner, including the incentive distribution rights is as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Common Unit:		
Up to and including $0.25 per Unit	98.00%	2.00%
First Target - $0.251 per Unit up to and including $0.28 per Unit	84.74%	15.26%
Second Target - $0.281 per Unit up to and including $0.33 per Unit	74.26%	25.74%
Over Second Target - Cash distributions greater than $0.33 per Unit	49.02%	50.98%

Index

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

We paid or will pay the following distributions in 2007 and 2008:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
First quarter 2007	May 2007	$ 0.220	$ 3,032	$ 62	$ -	$ 3,094
Second quarter 2007	August 2007	$ 0.230	$ 3,170(1)	$ 65	$ -	$ 3,235(1)
Third quarter 2007	November 2007	$ 0.270	$ 7,646	$ 156	$ 90	$ 7,892
Fourth quarter 2007	February 2008	$ 0.285	$ 10,903	$ 222	$ 245	$ 11,370
First quarter 2008	May 2008	$ 0.300	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008 (2)	$ 0.315	$ 12,427	$ 254	$ 633	$ 13,314

(1) The distribution paid 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 rights to receive such distributions, instead receiving purchase price adjustments with us.

(2) This distribution will be paid on August 14, 2008 to the general partner and unitholders of record as of August 7, 2008.

Net Income (Loss) Per Common Unit

Subject to the applicability of Emerging Issues Task Force Issue No. 03-6 ("EITF 03-6"), Participating Securities and the Two-Class Method under Financial Accounting Standards Board Statement No. 128," as discussed below, our net income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated 98% to the limited partners and 2% to the general partner. Basic net income per limited partner unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding limited partner units during the period. Diluted net income per common unit is calculated in the same manner, but also considers the impact to common units for the potential dilution from phantom units outstanding.

In a period of net operating losses, incremental phantom units are excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. During 2008, we have reported net income; therefore incremental phantom units have been included in the calculation of diluted earnings per unit.

EITF 03-6 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock (or partnership distributions to unitholders). EITF 03-06 applies to any accounting period where our aggregate net income exceeds our aggregate distribution. In such periods, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed from an economic or practical perspective. EITF 03-6 does not impact our overall net income or other financial results; however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner units. This result occurs as a larger portion of our aggregate earnings is allocated (as if distributed) to our general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given period. Our aggregate net earnings have not exceeded our aggregate distributions; therefore EITF 03-6 has not had an impact on our calculation of earnings per unit. EITF 07-4, which will be effective for us beginning in 2009, will change the allocation of net income among our general partner and limited partners as described in Note 2.

Index

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

The following table sets forth the computation of basic net income per common unit.

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Numerators for basic and diluted net income per common unit:				
Net income (loss)	$ 7,328	$ (1,372)	$ 8,973	$ 213
Less: General partner's incentive distribution paid	(429)	-	(674)	-
Subtotal	6,899	(1,372)	8,299	213
Less general partner 2% ownership	(138)	27	(166)	(4)
Net income (loss) available for common unitholders	$ 6,761	$ (1,345)	$ 8,133	$ 209
Denominator for basic per common unit:				
Common Units	38,675	13,784	38,464	13,784
Denominator for diluted per common unit:				
Common Units	38,675	13,784	38,464	13,784
Phantom Units	56	-	50	-
	38,731	13,784	38,514	13,784
Basic and diluted net income (loss) per common unit	$ 0.17	$ (0.09)	$ 0.21	$ 0.02

11. Business Segment Information

Our operations consist of four operating segments: (1) Pipeline Transportation – interstate and intrastate crude oil, and to a lesser extent, natural gas and CO_2 pipeline transportation; (2) Refinery Services – processing high sulfur (or “sour”) gas streams as part of refining operations to remove the sulfur and sale of the related by-product; (3) Industrial Gases – the sale of CO_2 acquired under volumetric production payments to industrial customers and our investment in a syngas processing facility, and (4) Supply and Logistics – terminaling, blending, storing, marketing, gathering, and transporting by truck crude oil and petroleum products and other dry goods. Our Supply and Logistics segment was previously known as Crude Oil Gathering and Marketing. With the Davison acquisition, we expanded our operations into petroleum products and other transportation services, and combined these operations due to their similarities and our approach to managing these operations. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures, including segment margin, segment volumes where relevant and maintenance capital investment. The tables below reflect our segment information as though the current segment designations had existed in all periods presented.

Index

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

We evaluate segment performance based on segment margin. We calculate segment margin as revenues less costs of sales and operating 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 our direct financing leases.

	Pipeline Transportation	Refinery Services	Industrial Gases (a)	Supply & Logistics	Total
Three Months Ended June 30, 2008					
Segment margin excluding depreciation and amortization (b)	$ 6,828	$ 17,616	$ 3,043	$ 9,492	$ 36,979
Capital expenditures	$ 77,246	$ 559	$ -	$ -	$ 77,805
Maintenance capital expenditures	$ -	$ 208	$ -	$ -	$ 208
Revenues:					
External customers	$ 8,885	$ 55,727	$ 4,450	$ 569,477	$ 638,539
Intersegment (d)	2,001	-	-	-	2,001
Total revenues of reportable segments	$ 10,886	$ 55,727	$ 4,450	$ 569,477	$ 640,540
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

Index

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

	Pipeline Transportation	Refinery Services	Industrial Gases (a)	Supply & Logistics	Total
Six Months Ended June 30, 2008					
Segment margin excluding depreciation and amortization (b)	$ 11,471	$ 31,204	$ 5,819	$ 15,753	$ 64,247
Capital expenditures	$ 78,524	$ 1,710	$ 2,210	$ 4,603	$ 87,047
Maintenance capital expenditures	$ 165	$ 489	$ -	$ 330	$ 984
Net fixed and other long-term assets (c)	$ 286,593	$ 449,637	$ 46,387	$ 143,980	$ 926,597
Revenues:					
External customers	$ 15,673	$ 99,639	$ 8,320	$ 999,595	$ 1,123,227
Intersegment (d)	3,498	-	-	-	3,498
Total revenues of reportable segments	$ 19,171	$ 99,639	$ 8,320	$ 999,595	$ 1,126,725
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 long-term 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

Index

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

a) Industrial gases includes our CO2 marketing operations and our equity income from our investments in T&P Syngas and Sandhill.

b) Segment margin was calculated as revenues less cost of sales and operating expenses, excluding depreciation and amortization. It includes our share of the operating income of equity joint ventures. A reconciliation of segment margin to income before income taxes and minority interest for the periods presented is as follows:

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Segment margin excluding depreciation and amortization	$ 36,979	$ 6,612	$ 64,247	$ 13,693
General and administrative expenses	(9,166)	(5,600)	(17,690)	(8,928)
Depreciation and amortization expense	(16,721)	(2,046)	(33,510)	(3,974)
Net (loss) gain on disposal of surplus assets	(76)	8	(94)	24
Interest expense, net	(2,039)	(321)	(3,708)	(547)
Income (loss) before income taxes and minority interest	$ 8,977	$ (1,347)	$ 9,245	$ 268

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 were conducted on an arm’s length basis.

Index

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

12. 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,	
	2008	2007
Truck transportation services provided to Denbury	$ 1,220	$ 878
Pipeline transportation services provided to Denbury	$ 3,314	$ 2,494
Payments received under direct financing leases from Denbury	$ 594	$ 594
Pipeline transportation income portion of direct financing lease fees with Denbury	$ 1,798	$ 318
Pipeline monitoring services provided to Denbury	$ 48	$ 60
Directors' fees paid to Denbury	$ 101	$ 74
CO2 transportation services provided by Denbury	$ 2,632	$ 2,334
Crude oil purchases from Denbury	$ -	$ 29
Operations, general and administrative services provided by our general partner	$ 25,789	$ 10,772
Distributions to our general partner on its limited partner units and general partner interest	$ 2,786	$ 559
Sales of CO2 to Sandhill	$ 1,464	$ 1,281
Petroleum products sales to Davison family businesses	$ 654	$ -

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 supply and logistics revenues.

Denbury is the only shipper on our Mississippi pipeline other than us, and we earn tariffs for transporting their oil. We also earned fees from Denbury under the direct financing lease arrangements for the Olive and Brookhaven crude oil pipelines and the Brookhaven CO2 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 unaudited statements 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 person less than the rate at which our independent directors were paid.

CO2 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 2008, the inflation-adjusted transportation fee averaged $0.1895 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 June 30, 2008 and December 31, 2007, we owed Denbury $1.0 million, respectively, for purchases of crude oil and CO_2 transportation charges. Denbury owed us $1.7 million and $0.9 million for transportation services at June 30, 2008 and December 31, 2007, respectively. We owed our general partner $1.0 million and $0.7 million for administrative services at June 30, 2008 and December 31, 2007, respectively. At June 30, 2008 and December 31, 2007, Sandhill owed us $0.8 and $0.5 million for purchases of CO_2, respectively. At December 31, 2007, we owed the Davison family entities $0.8 million for reimbursement of costs paid primarily related to employee transition services.

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

Drop-down transactions

On May 30, 2008, we entered into a $175 million financing lease arrangement with Denbury Onshore for its NEJD Pipeline System, and acquired its Free State CO2 pipeline system for $75 million, consisting of $50 million cash and $25 million of our common units. See Note 3.

Financing

Our general partner, a wholly owned subsidiary of Denbury, guarantees our obligations under our credit facility. Our general partner's principal assets are its general and limited partnership interests in us. Our credit agreement obligations are not guaranteed by Denbury or any of its other subsidiaries. Our credit facility is non-recourse to our general partner, except to the extent of its pledge of its 0.01% general partner interest in Genesis Crude Oil, L.P.

We guarantee 50% of the obligation of Sandhill to a bank. At June 30, 2008, the total amount of Sandhill's obligation to the bank was $3.6 million; therefore, our guarantee was for $1.8 million.

13. Major Customers and Credit Risk

Due to the nature of our supply and logistics operations, a disproportionate percentage of our trade receivables consists of 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 accounted for 17% of total revenues in the first half of 2008. 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. The majority of the revenues from these customers in both periods relate to our crude oil supply and logistics operations.

14. Supplemental Cash Flow Information

Cash received by us for interest for the six months ended June 30, 2008 and 2007 was $94,000 and $42,000, respectively. Payments of interest and commitment fees were $3,883,000 and $204,000 for the six months ended June 30, 2008 and 2007, respectively.

Cash paid for income taxes during the six months ended June 30, 2008 was $376,000.

At June 30, 2008, we had incurred liabilities for fixed asset and other asset additions totaling $1.5 million that had not been paid at the end of the second quarter, and, therefore, are not included in the caption "Payments to acquire fixed assets" and "Other, net" under investing activities on the Unaudited Consolidated Statements of Cash Flows. At June 30, 2007, we had incurred $0.1 million of liabilities that had not been paid at that date and are not included in "Payments to acquire fixed assets" under investing activities.

In May 2008, we issued common units with a value of $25 million as part of the consideration for the acquisition of the Free State Pipeline from Denbury. This common unit issuance is a non-cash transaction and the value of the assets acquired is not included in investing activities and the issuance of the common units is not reflected under financing activities in our Unaudited Consolidated Statements of Cash Flows.

Index

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

15. Derivatives

Our market risk in the purchase and sale of crude oil and petroleum products 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, fuel oil and petroleum products 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, "Accounting for Derivative Instruments and Hedging Activities." At June 30, 2008, 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, 2008. We marked these contracts to fair value at June 30, 2008. During the three and six months ended June 30, 2008, we recorded losses of \$3.0 million and \$4.0 million, respectively, related to derivative transactions, which are included in the Unaudited Consolidated Statements of Operations under the caption "Supply and logistics costs." We did not utilize any derivatives that were accounted for as hedges during the three and six months ended June 30, 2008.

The consolidated balance sheet at June 30, 2008 includes a decrease in other current assets of \$0.8 million as a result of these derivative transactions. The consolidated balance sheet at December 31, 2007 included a decrease in other current assets of \$0.7 million as a result of derivative transactions.

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, 2008 and December 31, 2007.

16. Contingencies

Guarantees

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

We guaranteed 50% of the obligations of Sandhill under a credit facility with a bank. At June 30, 2008, Sandhill owed $3.6 million; therefore our guaranty was $1.8 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year.

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.

Index

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

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 $0.8 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.

In connection with the sale of pipeline assets in Texas in the fourth quarter of 2003, we retained responsibility for environmental matters related to the operations of those pipelines in the periods prior to the date of the sales, subject to certain conditions. On the majority of the pipelines sold, our responsibility for any environmental claim will not exceed an aggregate total of $2 million. Our responsibility for indemnification related to these sales will cease in

2013.

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.

Index

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

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.

17. Unit-Based Compensation Plans

Stock Appreciation Rights Plan

The adjustment of the liability for our stock appreciation rights plan to its fair value at June 30, 2008 resulted in a net credit to expense for the six months ended June 30, 2008 of $0.6 million, with $0.5 million, $0.1 million and $0.1 million included in general and administrative expenses, pipeline operating costs, and supply and logistics operating costs, respectively. Expense of $0.1 million was recorded to refinery services operating costs related to grants awarded in the first quarter of 2008. The decrease in our common unit market price from December 31, 2007 to June 30, 2008 of $5.05 reduced the accrual for the plan, providing a credit to the expense we recorded under our plan during the six months ended June 30, 2008. For the three months ended June 30, 2008, we recorded $0.2 million of expense for our stock appreciation rights plan, with $0.1 million included in each of general and administrative expenses and supply and logistics costs.

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, supply and logistics 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, supply and logistics operating costs, and pipeline operating costs, respectively.

The following table reflects rights activity under our plan during the six months ended June 30, 2008:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at January 1, 2008	593,458	$ 15.45		
Granted	536,308	$ 20.83		
Exercised	(25,563)	$ 20.48		
Forfeited or expired	(45,833)	$ 20.90		
Outstanding at June 30, 2008	1,058,370	$ 18.07	8.4	$ 2,547
Exercisable at June 30, 2008	310,324	$ 14.59	6.6	$ 1,600

The weighted-average fair value at June 30, 2008 of rights granted during the first half of 2008 was $3.03 per right, determined using the following assumptions:

Assumptions Used for Fair Value of Rights

	Granted in 2008
Expected life of rights (in years)	5.75 - 6.50
Risk-free interest rate	3.58% - 3.67%
Expected unit price volatility	33.85%
Expected future distribution yield	6.00%

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

The total intrinsic value of rights exercised during the first six months of 2008 was $0.3 million, which was paid in cash to the participants.

At June 30, 2008, there was $1.4 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, 2008 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 date until the rights are exercised, forfeited, or expire. For the awards outstanding at June 30, 2008, the remaining cost will be recognized over a weighted average period of 1.0 year.

2007 Long Term Incentive Plan

Subject to adjustment as provided in the 2007 LTIP, awards up to an aggregate of 1,000,000 units may be granted under the 2007 LTIP, of which 928,472 remain authorized for issuance at June 30, 2008. In February 2008, 9,166 Phantom Units were granted with vesting at the end of three years. The aggregate grant date fair value of these Phantom Unit awards was $0.2 million based on the grant date market price of our common units of $17.89 per unit, adjusted for distributions that holders of phantom units will not receive during the vesting period. In June 2008, 23,000 Phantom Units were granted with vesting at the end of one year. The aggregate grant date fair value of these Phantom Unit awards was $0.5 million based on the grant date market price of our common units of $20.12 per unit, adjusted for distributions that holders of phantom units will not receive during the vesting period.

As of June 30, 2008, there was $1.2 million of unrecognized compensation expense related to these units. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 1.4 years.

The following table summarizes information regarding our non-vested Phantom Unit grants as of June 30, 2008:

Non-vested Phantom Unit Grants	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2008	39,362	$ 21.92
Granted	32,166	$ 19.48
Non-vested at June 30, 2008	71,528	$ 20.82

18. Fair-Value Measurements

As discussed in Note 2, we partially adopted SFAS 157 effective January 1, 2008 which defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants at the measurement date. SFAS 157 establishes a three-level fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy requires entities to maximize the use of observable inputs and minimize the use of unobservable inputs. The three levels of inputs used to measure fair value are as follows:

Level 1: Quoted prices in active markets for identical, unrestricted assets or liabilities.

Level 2: Unobservable market-based inputs or unobservable inputs that are corroborated by market data.

Level 3: Unobservable inputs that are not corroborated by market data, which require us to develop our own assumptions. These inputs include certain pricing models, discounted cash flow methodologies and similar techniques that use significant unobservable inputs.

Our derivative contracts are exchange-traded futures and exchange-traded option contracts. The fair value of these exchange-traded derivative contracts is based on unadjusted quoted prices in active markets and is, therefore, included in Level 1. See Note 15 for additional information on our derivative instruments.

We generally apply fair value techniques on a non-recurring basis associated with (1) valuing the potential impairment loss related to goodwill pursuant to SFAS 142, and (2) valuing potential impairment loss related to long-lived assets accounted for pursuant to SFAS 144.

Index

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

Assets and liabilities measured at fair value on a recurring basis are summarized below (in thousands):

	Carrying Amount	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Crude oil and petroleum products derivative instruments (based on quoted market prices on NYMEX)	$ (9,042)	$ 9,042	$ -	$ -

19. Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income taxes. Our taxable income or loss is includible in the federal income tax returns of each of our partners.

A portion of the operations we acquired in the Davison transaction are owned by wholly-owned corporate subsidiaries that are taxable as corporations. We pay federal and state income taxes on these operations. The income taxes associated with these operations are accounted for in accordance with SFAS 109 “Accounting for 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.

For the three and six months ended June 30, 2008, we have provided current tax expense in the amount of $5.3 million and $5.5 million, respectively, as the estimate of the taxes that will be owed on our income for the period, and a deferred tax benefit of $3.6 million and $5.2 million, respectively, related to temporary differences, related primarily to differences between amortization of intangible assets for financial reporting and tax purposes. We recorded an increase of $4.3 million in the liability for uncertain tax benefits during the six months ended June 30, 2008. This increase was attributable to uncertain tax positions associated with deferred tax liabilities and goodwill.

20. Subsequent Event – Investment in DG Marine Transportation, LLC

On July 18, 2008, we completed the acquisition of the inland marine transportation business of Grifco Transportation, Ltd. (“Grifco”) and two of Grifco’s affiliates through a joint venture with TD Marine, LLC, an entity formed by members of the Davison family. TD Marine will own (indirectly) an effective 51% economic interest in the joint venture, DG Marine Transportation, LLC (“DG Marine”), and we will own (directly and indirectly) an effective 49% economic interest.

Grifco received initial purchase consideration of approximately $80 million, comprised of $63.3 million in cash and $16.7 million, or 837,690, of our common units. A portion of the units are subject to certain lock-up restrictions. DG

Marine acquired substantially all of Grifco's assets, including twelve barges, seven push boats, certain commercial agreements, and office space. Additionally, DG Marine and/or its subsidiaries acquired the rights and assumed the obligations to take delivery of four new barges in late third quarter of 2008 and four additional new barges early in first quarter of 2009 (at a total price of approximately $27 million). Upon delivery of the eight new barges, the acquisition of three additional push boats (at an estimated cost of approximately $6 million), and after placing the barges and push boats into commercial operations, DG Marine will be obligated to pay Grifco an additional $12 million in cash as additional purchase consideration, bringing the total value of the joint investment to approximately $125 million.

The acquisition and related closing costs were funded with equity contributions from TD Marine and us of $25.5 million and $24.5 million, respectively, and with borrowings of $32.9 million under a new DG Marine $75 million, which is non-recourse to us and TD Marine (other than with respect to our initial investments). Although DG Marine's debt is non-recourse to us, our ownership interest in DG Marine is pledged to secure that indebtedness.

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

We have entered into a subordinated loan agreement with DG Marine whereby we may (at our sole discretion) lend up to $25 million to DG Marine. The loan agreement provides for DG Marine to pay us interest on any loans at the rate at which we borrowed funds under our credit facility plus 1%. Those loans will mature on January 31, 2012. Under that subordinated loan agreement, DG Marine is required to make monthly payments to us of principal and interest to the extent DG Marine has any available cash that otherwise would have been distributed to the owners of DG Marine in respect of their equity interest. DG Marine's revolving credit facility includes restrictions on DG Marine's ability to make payments under the subordinated loan agreement.

In connection with the DG Marine investment, we redeemed 837,690 common units from the Davison family for a cash value of $16.7 million, and we issued 837,690 common units to Grifco valued at $16.7 million as a portion of our initial equity contribution in DG Marine. Our total number of outstanding common units did not change as a result of that investment.

Index

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:

- Overview
- Drop-down Transactions
- Investment in DG Marine Transportation, LLC
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Results of Operations
- New Accounting Pronouncements

In the discussions that follow, we will focus on two measures that we use to manage our 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 revenues less cost of sales and operating expenses (excluding depreciation and amortization) plus our equity in the operating income of joint ventures. A reconciliation of segment margin to income from continuing operations is included in our segment disclosures in Note 11 to the consolidated financial statements.

Available Cash before Reserves (a non-GAAP measure) is net income as adjusted for specific items, 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 substitution of cash generated by our joint ventures in lieu of our equity income attributable to our joint ventures, and the subtraction of maintenance capital expenditures, which are expenditures that are necessary to sustain existing (but not to provide new sources of) cash flows. 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.

Overview

The second quarter of 2008 was the third full quarter that included the operations acquired from the Davison family in July 2007. The increases in Available Cash before Reserves resulting from this acquisition enabled us to declare our twelfth consecutive increase in our quarterly distribution. On July 28, 2008, we announced that our distribution to our common unitholders relative to the second quarter of 2008 will be $0.315 per unit (to be paid in August 2008), which is an increase of 5% relative to the distribution for the first quarter of 2008. This distribution amount represents a 37% increase from our distribution of $0.23 per unit for the second quarter of 2007. During the second quarter of 2008, we paid a distribution of $0.30 per unit related to the first quarter of 2008.

During the second quarter of 2008, we generated $26.2 million of Available Cash before Reserves, and we will distribute $13.3 million to holders of our common units and general partner for the second quarter. During the second quarter of 2008, cash provided by operating activities was $5.3 million.

In the second quarter of 2008, we reported net income of $7.3 million, or $0.17 per common unit. Non-cash depreciation and amortization totaling $16.7 million reduced net income during the second quarter.

For the six months ended June 30, 2008, we generated net income of $9.0 million, or $0.21 per common unit, with $0.6 million of that income attributable to a reduction in the accrual we recorded for our stock appreciation rights plan. The decrease in our common unit market price from December 31, 2007 to June 30, 2008 of $5.05 reduced the accrual for the plan, providing a credit to the expense we recorded under our plan during the six months ended June 30, 2008.

Drop-down Transactions

We completed two “drop-down” transactions with Denbury involving two of their existing CO2 pipelines - the NEJD and Free State CO2 pipelines. We paid for these pipeline assets with $225 million in cash and 1,199,041 common units valued at $25 million based on the average closing price of our units for the five trading days surrounding the closing date of the transaction. We expect to receive approximately $30 million per annum, in the aggregate, under the lease agreement for the NEJD pipeline and the Free State pipeline transportation services agreement. Future payments for the NEJD pipeline are fixed at $20.7 million per year during the term of the financing lease, and the payments related to the Free State pipeline are dependent on the volumes of CO2 transported therein, with a minimum monthly payment of $0.1 million.

On August 5, 2008, Denbury announced that the economic impact of an approved tax accounting method change providing for an acceleration of tax deductions will likely affect certain types of future asset “drop-downs” to us. Transactions which are not sales for tax purposes for Denbury, such as the lease arrangement for the NEJD pipeline, would not be affected provided the transactions meet other tax structuring criteria for Denbury and us. Transactions which constitute a sale for tax purposes for Denbury, like the Free State pipeline transaction, are likely to be discontinued. While Denbury has also stated it would consider other options and ways to use us as a financing vehicle, there can be no assurances as to the amount, or timing, of any potential future asset “drop-downs” from Denbury to us.

Investment in DG Marine Transportation, LLC

On July 18, 2008, we invested $24.5 million in DG Marine Transportation, LLC, a joint venture in which we hold (directly and indirectly) a 49% interest. The remaining 51% interest is owned (indirectly) by TD Marine, LLC, an entity formed by members of the Davison family. DG Marine acquired the inland marine transportation business of Grifco Transportation, Ltd. Grifco received initial purchase consideration of approximately $80 million, comprised of $63.3 million in cash and $16.7 million of our common units. A portion of the units are subject to certain lock-up restrictions. DG Marine acquired substantially all of Grifco’s assets, including twelve barges, seven push boats, certain commercial agreements, and office space. Additionally, DG Marine and/or its subsidiaries acquired the rights and assumed the obligations to take delivery of four new barges in late third quarter of 2008 and four additional new barges early in first quarter of 2009 (at a total price of approximately $27 million). Upon delivery of the eight new barges, the acquisition of three additional push boats (at an estimated cost of approximately $6 million), and after placing the barges and push boats into commercial operations, DG Marine will be obligated to pay Grifco an additional $12 million in cash as additional purchase consideration, bringing the total value of the joint investment to approximately $125 million.

The acquisition and related closing costs were funded with $50 million of aggregate equity contributions from TD Marine and us, in proportion to our ownership percentages, and with borrowings of $32.9 million under a new DG Marine $75 million revolving credit facility, which is non-recourse to us and TD Marine (other than with respect to our initial investments). Although DG Marine’s debt is non-recourse to us, our ownership interest in DG Marine is pledged to secure that indebtedness.

We have entered into a subordinated loan agreement with DG Marine whereby we may (at our sole discretion) lend up to $25 million to DG Marine. The loan agreement provides for DG Marine to pay us interest on any loans at the rate at which we borrowed funds under our credit facility plus 1%. Those loans will mature on January 31, 2012. Under that subordinated loan agreement, DG Marine is required to make monthly payments to us of principal and interest to the extent DG Marine has any available cash that otherwise would have been distributed to the owners of DG Marine in respect of their equity interest. DG Marine’s revolving credit facility includes restrictions on DG Marine’s ability to make payments under the subordinated loan agreement.

In connection with the DG Marine investment, we redeemed 837,690 common units from the Davison family for a cash value of $16.7 million, and we issued 837,690 common units to Grifco valued at $16.7 million as a portion of our initial equity contribution in DG Marine. Our total number of outstanding common units did not change as a result of that investment.

Liquidity and Capital Resources

Capital Resources/Sources of Cash

We anticipate that cash generated from our operations will be the primary source of cash used to fund our distributions and our maintenance capital expenditures. For the six months ended June 30, 2008, cash generated from our operations was $22.7 million. We periodically utilize our existing credit facility to fund working capital needs. We also expect to utilize our existing credit facility to fund internal growth projects. Our credit facility has a maximum facility amount of $500 million, of which up to $100 million may be used for letters of credit. The borrowing base under the facility at June 30, 2008 was approximately $447 million, and is recalculated quarterly and at the time of acquisitions. When we provide our lenders with our second quarter compliance data in mid-August, our borrowing base will increase to the maximum facility amount of $500 million, providing approximately $175 million of remaining availability.

Index

In the last two years, we have adopted a growth strategy that has dramatically increased our cash requirements. Our existing credit facility gives us $175 million of growth capital. To the extent any of our possible growth initiatives requires a greater amount of capital, we would have to access new sources of capital, including public and private debt and equity markets. Conditions in the capital markets for debt and equity may make the terms related to the cost of credit or equity prohibitive in relation to the economics of an acquisition. Additionally, availability of capital may be limited while financial institutions and investors assess their liquidity positions. Accordingly, no assurance can be made that we will be able to raise the necessary funds on satisfactory terms to execute our growth strategy. If we are unable to raise the necessary funds, we may be required to defer our growth plans until such time as funds become available.

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 9 of the Notes to the Unaudited Consolidated Financial Statements.

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. The timing of capital expenditures and the related effect on our recorded liabilities affects operating cash flows.

The majority of the accounts receivable reflected on our consolidated balance sheets relate to our crude oil operations. These 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. Accounts receivable in our fuel procurement business also settle within 30 days of delivery. Over 80% of the $235.2 million aggregate receivables on our consolidated balance sheet at June 30, 2008 relate to our crude oil and fuel procurement businesses.

Investing. We utilized some of our cash flow for capital expenditures and other investing activities. We paid $238.4 million for capital expenditures and CO2 pipeline transactions and received $0.4 million from the sale of surplus assets. We received distributions of $0.4 million from our T&P Syngas joint venture that exceeded our share of the earnings of T&P Syngas during the first six months of 2008. We also invested an additional $3.5 million in other investments.

Financing. Net cash of $215.6 million was provided by financing activities. Our net borrowings under our credit facility were $239 million, primarily as a result of the $225 million borrowed to fund the drop-down transactions with Denbury. We paid distributions totaling $23.5 million to our limited partners and our general partner during the six month period, and received $0.1 million from other financing activities.

Index

Capital Expenditures. A summary of our capital expenditures, in the six months ended June 30, 2008 and 2007 is as follows:

	Six Months Ended June 30, 2008	2007
	(in thousands)	
Capital expenditures for asset purchases:		
Free State Pipeline acquisition	75,000	-
Total asset purchases	75,000	-
Capital expenditures for property, plant and equipment:		
Maintenance capital expenditures:		
Pipeline transportation assets	165	559
Supply and logistics assets	304	112
Refinery services assets	489	-
Administrative and other assets	26	23
Total maintenance capital expenditures	984	694
Growth capital expenditures:		
Pipeline transportation assets	3,359	-
Supply and logistics assets	4,273	-
Refinery services assets	1,221	-
Total growth capital expenditures	8,853	-
Total	9,837	694
Capital expenditures attributable to unconsolidated affiliates:		
Faustina project	2,210	-
Total	2,210	-
Total capital expenditures	$ 87,047	$ 694

During the remainder of 2008, we expect to expend approximately $3.8 million for maintenance capital projects in progress or planned. Those expenditures are expected to include approximately $0.5 million of improvements in our refinery services business, $0.2 million in our crude oil pipeline operations, $1.5 million related to the relocation of our headquarters office when our existing lease ends in October 2008 and the remainder on projects related to our truck transportation and information technology areas. Most of our truck fleet is less than two years old, so we do not anticipate making any significant expenditures for vehicles in 2008; however, in future years we expect to spend $4 million to $5 million per year on vehicle replacements. 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.

We have started construction of an expansion of our existing Jay System that will extend the pipeline to producers operating in southern Alabama. That expansion will consist of approximately 33 miles of pipeline and gathering connections to approximately 35 wells and will include storage capacity of 20,000 barrels. We expect to spend a total of approximately $7.6 million on this project in 2008. Our refinery services segment expects to expend approximately $10.1 million on projects currently in progress to expand its operations in 2008 to two additional refineries. We also increased our base level of crude oil inventory by $4.3 million related to our Port Hudson facility, which is included in fixed assets. This is the level of inventory needed to ensure efficient and uninterrupted operations of the facility.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital discussed above in "Capital Resources -- Sources of Cash." We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows.

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 six quarters, including the distribution to be paid for the second quarter of 2008, as shown in the table below (in thousands, except per unit amounts).

Index

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
First quarter 2007	May 2007	$ 0.220	$ 3,032	$ 62	$ -	$ 3,094
Second quarter 2007	August 2007	$ 0.230	$ 3,170(1)	$ 65	$ -	$ 3,235 (1)
Third quarter 2007	November 2007	$ 0.270	$ 7,646	$ 156	$ 90	$ 7,892
Fourth quarter 2007	February 2008	$ 0.285	$ 10,903	$ 222	$ 245	$ 11,370
First quarter 2008	May 2008	$ 0.300	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008 (2)	$ 0.315	$ 12,427	$ 254	$ 633	$ 13,314

(1) The distribution paid 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 rights to receive such distributions, instead receiving purchase price adjustments with us.

(2) This distribution will be paid on August 14, 2008 to the general partner and unitholders of record as of August 7, 2008.

See Notes 9 and 10 of the Notes to the Unaudited Consolidated Financial Statements.

Available Cash before Reserves for the three and six months ended June 30, 2008 is as follows (in thousands):

	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
Net income	$ 7,328	$ 8,973
Depreciation and amortization	16,721	33,510
Cash received from direct financing leases not included in income	397	544
Cash effects of sales of certain assets	181	426
Effects of available cash generated by investments in joint ventures not included in income	643	1,066
Cash effects of stock appreciation rights plan	(113)	(271)
Loss on asset disposals	76	94
Non-cash tax expense (benefits)	700	(926)
Other non-cash credits	460	(460)
Maintenance capital expenditures	(208)	(984)
Available Cash before Reserves	$ 26,185	$ 41,972

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) for the three and six months ended June 30, 2008 below. For the three and six months ended June 30, 2008, cash flows provided by operating activities were $5.3 million and $22.7 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.

Index

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, 2008, is as follows (in thousands):

	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
Cash flows from operating activities	$ 5,313	$ 22,696
Adjustments to reconcile operating cash flows to Available Cash:		
Maintenance capital expenditures	(208)	(984)
Proceeds from sales of certain assets	181	426
Amortization of credit facility issuance fees	(267)	(535)
Effects of available cash generated by investments in joint ventures not included in cash flows from operating activities	329	413
Available cash from NEJD pipeline not yet received and included in cash flows from operating activities	1,722	1,722
Net effect of changes in operating accounts not included in calculation of Available Cash	19,115	18,234
Available Cash before Reserves	$ 26,185	$ 41,972

Index

Commitments and Off-Balance-Sheet Arrangements

Contractual Obligations and Commercial Commitments

In addition to the credit facility discussed above, we have contractual obligations under operating leases as well as commitments to purchase crude oil. The table below summarizes our obligations and commitments at June 30, 2008 (in thousands).

Commercial Cash Obligations and Commitments	Payments Due by Period Less than one year	1 - 3 years	3 - 5 Years	More than 5 years	Total
Contractual Obligations:					
Long-term debt (1)	$ -	$ -	$ 319,000	$ -	$ 319,000
Estimated interest payable on long-term debt (2)	17,545	35,090	6,585	-	59,220
Operating lease obligations	6,771	8,490	4,696	10,564	30,521
Capital expansion projects (3)	5,818	-	-	-	5,818
Unconditional purchase obligations (4)	208,662	34,350	3,596	-	246,608
Other Cash Commitments:					
Asset retirement obligations (5)	100			3,656	3,756
FIN 48 tax liabilities (6)	5,512	-	-	-	5,512
Total	$ 244,408	$ 77,930	$ 333,877	$ 14,220	$ 670,435

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of November 15, 2011.

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(2) Interest on our long-term debt is at market-based rates. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at June 30, 2008 remained outstanding through the final maturity date of November 15, 2011, and interest rates remained at the June 30, 2008 market levels through November 15, 2011.

(3) We have signed commitments to expand our Jay pipeline system and to construct sour gas processing facilities at a new location. See "Capital Expenditures" above.

(4) Unconditional purchase obligations include agreements to purchase good and services that are enforceable and legally binding and specify all significant terms. Contracts to purchase crude oil and petroleum products are generally at market-based prices. For purposes of this table, estimated volumes and market prices at June 30, 2008, were used to value those obligations. The actual physical volumes and settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, changes in market prices and other conditions beyond our control.

(5) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $1.2 million, as determined under FIN 47 and SFAS 143.

(6)

The estimated FIN 48 tax liabilities will be settled as a result of expiring statutes or audit activity. The timing of any particular settlement will depend on the length of the tax audit and related appeals process, if any, or an expiration of statute. If a liability is settled due to a stature expiring or a favorable audit result, the settlement of the FIN 48 tax liability would not result in a cash payment.

In addition to the contractual cash obligations included above, we also have a contingent obligation related to our acquisition of a 50% interest in Sandhill, which could require us to pay an additional $2 million for our interest.

We have guaranteed 50% of the $3.6 million debt obligation to a bank of Sandhill; however, we believe we are not likely to be required to perform under this guarantee as Sandhill is expected to make all required payments under the debt obligation.

Off-Balance Sheet Arrangements

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

Index

Results of Operations

The contribution of each of our segments to total segment margin in the second quarters and six-month periods of 2008 and 2007 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Pipeline transportation	$ 6,828	$ 2,227	$ 11,471	$ 5,095
Refinery services	17,616	-	31,204	-
Industrial gases	3,043	2,958	5,819	5,572
Supply and logistics	9,492	1,427	15,753	3,026
Total segment margin	$ 36,979	$ 6,612	$ 64,247	$ 13,693

Pipeline Transportation Segment

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 two CO2 pipelines in Mississippi to transport CO2 for Denbury. We also lease the NEJD pipeline to Denbury in a transaction accounted for by us as a direct financing lease. We also have several small natural gas gathering systems.

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 CO2 based tertiary recovery operations, we expect Denbury to add crude oil gathering and CO2 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 or re-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. In August 2007, we announced that we will construct an expansion of our existing Jay System that will extend to producers operating in southern Alabama. This extension will consist of approximately 33 miles of pipeline and gathering connections to approximately 35 wells and storage capacity of 20,000 barrels. We expect to place these facilities in service in the first quarter of 2009. The production from these wells is currently being transported to our existing Jay System by our trucks. This expansion will allow us to re-deploy the trucks to other operations.

Our Texas System is dependent on connecting carriers for supply, and on two refineries for demand for our services. Volumes on the Texas System fluctuate 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.

The Free State Pipeline is an 86-mile, 20" pipeline that extends from Denbury's CO2 source fields at the Jackson Dome, near Jackson, Mississippi, to Denbury's oil fields in east Mississippi. We entered into a twenty-year transportation services agreement to deliver CO2 on the Free State pipeline for Denbury's use in it tertiary recovery operations. Under the terms of the transportation services agreement, we are responsible for owning, operating, maintaining and making improvements to that pipeline. Denbury has rights to exclusive use of that pipeline and is required to use that pipeline to supply CO2 to its current and certain of its other tertiary operations in east

Mississippi. The transportation services agreement provides for a $100,000 per month minimum payment, which is accounted for as an operating lease, plus a tariff based on throughput.

We operate the Brookhaven CO_2 pipeline which is used to transport CO_2 from the NEJD pipeline to Brookhaven oil field. Denbury has the exclusive right to use this CO_2 pipeline.

The NEJD Pipeline System is a 183-mile, 20” CO_2 pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldson, Louisiana, currently being used by Denbury for its tertiary operations in southwest Mississippi. Denbury has the rights to exclusive use of the NEJD Pipeline System, will be responsible for all operations and maintenance on that system, and will bear and assume all obligations and liabilities with respect to that system. We entered into a twenty-year lease transaction with Denbury valued at $175 million and acquired certain security interests in the NEJD Pipeline System. Under the terms of the agreement, Denbury will make quarterly rent payments beginning August 30, 2008. These quarterly rent payments are fixed at $5,166,943 per quarter or approximately $20.7 million per year during the lease term at an interest rate of 10.25%. At the end of the lease term, we will reassign to Denbury all of our interests in the NEJD Pipeline for a nominal payment. This transaction is being accounted for as a direct financing lease.

Index

Operating results for our pipeline transportation segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$ 3,979	$ 3,458	$ 8,105	$ 6,994
Sales of crude oil pipeline loss allowance volumes	2,868	1,441	5,326	3,140
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	2,245	80	2,323	162
Tank rental reimbursements and other miscellaneous revenues	166	164	434	327
Total revenues from crude oil and CO2 tariffs, including revenues from direct financing leases	9,258	5,143	16,188	10,623
Revenues from natural gas tariffs and sales	1,628	1,192	2,983	2,500
Natural gas purchases	(1,568)	(1,112)	(2,854)	(2,347)
Pipeline operating costs	(2,490)	(2,996)	(4,846)	(5,681)
Segment margin	$ 6,828	$ 2,227	$ 11,471	$ 5,095
Barrels per day on crude oil pipelines:				
Total	67,434	57,127	66,733	57,627
Mississippi System	24,873	20,496	23,864	19,983
Jay System	11,828	11,602	13,222	12,230
Texas System	30,733	25,029	29,647	25,414

Three Months Ended June 30, 2008 Compared with Three Months Ended June 30, 2007

Pipeline segment margin for the second quarter of 2008 increased $4.6 million as compared to the second quarter of 2007. Revenues from crude oil tariffs and related sources and sales of pipeline loss allowance volumes increased a total of $1.9 million. Revenues from CO2 financing leases and tariffs contributed $2.2 million of the increase. Pipeline operating costs decreased $0.5 million between the two periods, and the contribution to segment margin from natural gas activities was consistent.

Crude oil tariff and direct financing lease revenues increased $0.5 million primarily due to volume increases on all of our pipeline systems totaling 10,307 barrels per day. The tariff on the Mississippi System is an incentive tariff, such that the average tariff per barrel decreases as the volumes increase, however the overall impact of an annual tariff increase on July 1, 2007 with the volume increase still resulted in improved revenues from this system by $0.1 million. As a result of the annual tariff increase on July 1, 2007, average tariffs on the Jay System increased by approximately $0.07 per barrel between the two periods, which, when combined with the 226 barrels per day increase in volumes, improved tariff revenues from this system by $0.1 million. Volumes on the Texas System increased by 5,704 barrels per day, resulting in an increase in revenues of $0.3 million. The impact on revenues of increases in volumes on the Texas System is not very significant due to the relatively low tariffs on that system. Approximately 78% of the volume on that system is shipped on a tariff of $0.31 per barrel.

Higher market prices for crude oil added $1.4 million to pipeline loss allowance revenues. Crude oil market prices have increased approximately $60 per barrel between the two quarters.

CO_2 tariff and direct financing lease revenues increased $2.2 million between the two quarters, with $1.5 million attributable to the one month we have owned the NEJD pipeline and $0.7 million to the Free State pipeline. The volume transported on the Free State pipeline for the month of June was 152 MMcf per day, with the transportation fee totaling $0.6 million and the minimum payment $0.1 million.

Index

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. Operations and maintenance costs, excluding the effects of our stock appreciation rights plan were flat when compared to the prior period. A decrease in the costs related to our stock appreciation right plan expense that relates to our pipeline operations personnel resulted in the decline in pipeline operating costs between the quarters.

Six Months Ended June 30, 2008 Compared with Six Months Ended June 30, 2007

For the six month periods, pipeline segment margin increased $6.4 million. $3.3 million is attributable to crude oil tariffs and related sources and pipeline loss allowance revenue increases, $2.2 million to CO2 pipelines, and $0.8 million to a reduction in pipeline operating costs.

Revenues from transportation on the Mississippi System increased $0.3 million from an increase in volumes of 3,881 barrels per day. As discussed above, the tariff for the Mississippi System is an incentive tariff under which incremental volumes result in a smaller tariff per barrel.

Volumes on the Jay System increased 992 barrels per day, increasing revenue by $0.3 million. The volume increase is due in part to the renewed interest by oil producers in the fields in the area and additional volumes we are bringing to the system from other locations. During the second quarter of 2008, volumes declined slightly due to maintenance at several separation plants providing volumes to the system. Variances in the average tariff per barrel on this system are affected by the annual tariff increase each year in July and the varying tariff rates depending on the distance volumes are transported.

Volumes on the Texas System increased 4,233 barrels per day, contributing $0.5 million of additional revenue between the six-month periods. Shippers on the system have increased the crude oil production that they acquire that is shipped on our pipeline to their refineries.

Revenues from pipeline loss allowance volumes have increased by $2.2 million due to the significant increase in market prices for crude oil between the first half of 2007 and the first half of 2008.

The decrease in pipeline operating costs between the two six-month periods is attributable to our stock appreciation rights plan. In the first half of 2007, we included $0.7 million in pipeline operating costs for the plan, resulting from the increase in our common unit price of $15.40 during the period. In the 2008 period, our common unit price decreased by $5.05, resulting in a credit to expense of $0.1 million, for a total variation of $0.8 million.

Refinery Services Segment

We acquired our refinery services segment in the Davison transaction in July 2007. That segment provides services to eight refining operations primarily located in Texas, Louisiana, and Arkansas. In our processing, we apply proprietary technology that uses large quantities of caustic soda (the primary input used by our proprietary process). Our refinery services business generates revenue by providing a service for which it receives 100% of the NaHS as compensation and by selling the NaHS, the by-product of our process, to approximately 100 customers. Some of the largest customers for the NaHS are copper mining companies in the United States and South America and paper mills in the United States.

The largest cost component of providing the service is acquiring and delivering caustic soda to our operations. Caustic soda, or NaOH, is the scrubbing agent introduced in the sour gas stream to remove the sulfur and generate the by-product, NaHS. Therefore the contribution to segment margin involves the revenues generated from the sales of NaHS less our total cost of providing the services, including the costs of acquiring and delivering caustic soda to our service locations. We estimate that approximately 65% of our NaHS sales are indexed, in one form or another, to our cost of caustic soda. We engage in other activities such as selling caustic soda, buying NaHS from other producers for re-sale to our customers and buying and selling sulfur, the financial results of which are also reported in our refinery services segment.

Segment margin from our refinery services for the second quarter of 2008 was $17.6 million, which when combined with the first quarter segment margin of $13.6 million, totals $31.2 million for the first six months of 2008. As we have only owned the operations of this segment since July 25, 2007, we are providing information comparing the first and second quarters of 2008. We believe the most meaningful measure of our success in this segment is the revenue generated from sales of NaHS after deducting delivery expenses, from both the volumes received as payment for rendering service as well as volumes obtained from third party producers. Included in the table below is information on our NaHS sales activity in the first two quarters of 2008.

Index

	Three Months Ended March 31, 2008	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
NaHS Sales			
Dry Short Tons (DST)	41,742	46,655	88,397
Net Sales	$ 27,530	$ 37,664	$ 65,194
Contribution Margin per DST	$ 260	$ 342	$ 303

During the first quarter of 2008, sales of NaHS, measured in dry short tons (DST) were 41,742 DST, or an average of 459 DST per day. The average sales price of the NaHS, net of delivery expenses, for the period was $660 per DST. For the second quarter of 2008, sales of NaHS were 46,655 DST, or an average of 513 DST per day. This approximately 12% increase in NaHS sales volumes resulted from increased demand from our customers in the mining, specialty chemicals and alumina refining businesses. The average sales price of NaHS increased to $807 per DST, primarily as a function of increases in our costs for caustic soda, the largest input to processing of the sour gas streams that result in NaHS. We also increased our sales prices to compensate for increased transportation costs for both delivery of raw materials to us and product to our customers. As we expand our sour gas processing services to additional refineries, we expect these NaHS sales volumes to continue to increase. The increased worldwide demand for copper has contributed to the increased demand for NaHS by mining customers in both the United States and South America.

The largest input to processing of the sour gas streams that result in NaHS is caustic soda. We also market caustic soda and sulfidic caustic not used for our processing. During the second quarter of 2008, our sales price for caustic soda was $531 per DST, an increase of 11% over the market price in the first quarter of 2008. We have generally been successful in increasing the sales price of NaHS to compensate for increases in caustic soda prices and maintaining or expanding the contribution of NaHS sales to our segment margin.

During the second quarter, we extended a contract with a refiner for an additional ten-year period. Contract extensions with major customers and changes to pricing in the contracts helped increase our contribution margin per DST by 32%.

Industrial Gases Segment

Our industrial gases segment includes the results of our CO2 sales to industrial customers and our share of the operating income of our 50% joint venture interests in T&P Syngas and Sandhill.

CO2 - Industrial Customers - We supply CO2 to industrial customers under seven long-term CO2 sales contracts. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price.

Index

Our industrial customers treat the CO2 and transport it to their own customers. The primary industrial applications of CO2 by these customers include beverage carbonation and food chilling and freezing. Based on historical data for 2004 through the first quarter of 2008, we can expect some seasonality in our sales of CO2. 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 in each of the last five quarters were as follows:

	Sales Mcf per Day
Second Quarter 2007	75,039
Third Quarter 2007	85,705
Fourth Quarter 2007	80,667
First Quarter 2008	73,062
Second Quarter 2008	79,968

Operating Results - Operating results from our industrial gases segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Revenues from CO2 sales	$ 4,450	$ 3,946	$ 8,320	$ 7,443
CO2 transportation and other costs	(1,391)	(1,281)	(2,663)	(2,425)
Equity in (losses) earnings of joint ventures	(16)	293	162	554
Segment margin	$ 3,043	$ 2,958	$ 5,819	$ 5,572
Volumes per day:				
CO2 sales - Mcf	79,968	75,039	76,515	71,120

Three Months Ended June 30, 2008 Compared with Three Months Ended June 30, 2007

The increase in margin from the industrial gases between the two quarterly periods was the result of an increase in CO2 sales volumes of 6.6%. Variations in the volumes sold among contracts with different pricing terms combined with inflation adjustment factors in the sales contracts resulted in the average sales price of the CO2 increasing $0.03 per Mcf, or 5.8%.

The increased volumes and the inflation adjustment to the rate we pay Denbury to transport the CO2 to our customers resulted in greater CO2 transportation costs in the second quarter of 2008 when compared to the 2007 quarter. The transportation rate increase between the two quarters was 4.3%.

Our share of the operating income from our joint ventures, T&P Syngas and Sandhill was a loss of $16,000 and $0.3 million, respectively, for the three months ended June 30, 2008 and 2007. We received cash distributions from the joint ventures totaling $0.6 million during the quarter.

Six Months Ended June 30, 2008 Compared with Six Months Ended June 30, 2007

For the six month periods, our industrial gases segment margin increased by $0.2 million, with CO_2 sales revenues, net of transportation costs increasing $0.6 million and our share of the equity in the earnings of joint ventures decreasing by $0.4 million. CO_2 sales volumes increased by 5,395 Mcf per day, the average sales price per Mcf increased by $0.01, and the average transportation rate per Mcf increased by $0.01. Although equity in our joint ventures declined, the decrease was due to non-cash charges, and distributions to us during the six month periods of each year remained consistent at approximately $1.3 million in each period.

Additional discussion of our joint ventures is included in Note 8 of the Notes to the Unaudited Consolidated Financial Statements.

Index

Supply and Logistics Segment

Our supply and logistics segment was previously known as our crude oil gathering and marketing segment. With the acquisition of the Davison businesses, we renamed the segment and we included the petroleum products, fuel logistics, terminaling, and truck transportation activities we acquired from the Davisons.

Our crude oil gathering and marketing operations are concentrated in Texas, Louisiana, Alabama, Florida, and Mississippi. Those operations - which involve purchasing, gathering, and transporting by trucks and pipelines operated by us and trucks, pipelines and barges operated by others, and reselling - help to ensure (among other things) a base supply source for our crude oil pipeline systems. Our profit for those services is derived from the difference between the price at which we re-sell 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 an extensive expertise, knowledge base, and skill set that facilitates our ability to capitalize on regional opportunities which arise from time to time in our market areas.

When the crude oil markets are in contango (oil prices for future deliveries are higher than for current deliveries), we may purchase and store crude oil as inventory for delivery in future months. When we purchase this inventory, we simultaneously enter into a contract to sell the inventory in the future period for a higher price, either with a counterparty or in the crude oil futures market. The maximum storage capacity available to us for use in this crude oil 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 15 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, an unfixed bonus that 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.

With the Davison acquisition, we gained approximately 225 trucks, 525 trailers, and 1.3 million barrels of existing leased and owned storage and expanded our activities to include transporting, storing and blending intermediate and finished refined products. In our petroleum products marketing operations, we primarily supply fuel oil, asphalt, petroleum feedstocks, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. The opportunities to purchase some of these products cannot be predicted, but the contribution to margin tends to be higher than in our recurring operations.

Operating results from our supply and logistics segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Supply and logistics revenue	$ 569,477	$ 190,735	$ 999,595	$ 364,014
Crude oil and products costs	(542,200)	(184,535)	(949,475)	(352,257)

Operating costs	(17,785)	(4,773)	(34,367)	(8,731)
Segment margin	$ 9,492	$ 1,427	$ 15,753	$ 3,026

Three Months Ended June 30, 2008 as Compared to Three Months Ended June 30, 2007

The portions of our supply and logistics operations acquired in the Davison transaction added approximately $7.0 million to our supply and logistics segment margin for the three months ended June 30, 2008.

Our existing crude oil gathering and marketing operations contribution for the three months ended June 30, 2008 was $1.1 million greater than the contribution for the three months ended June 30, 2007, with the improvement primarily related to improved margin from crude oil sales. Grade differentials related to the chemical composition of the crude oil and the desire in the market for that grade of crude oil create fluctuations in the differentials that can improve or reduce the margin we make on our crude oil transactions. During the second quarter of 2008 those grade differentials combined with volumetric gains and changes in other contract terms improved our margins from the sale of crude oil by $1.5 million.

Offsetting the increase in revenues from the crude oil margins and transportation was an increase of $0.6 million in field costs between the 2008 and 2007 second quarters. Fuel costs to operate our fleet of crude oil vehicles increased $0.5 million as diesel prices increased 57%. Costs related to repairs to our trucks and equipment increased $0.3 million and costs related to operating our terminal at Port Hudson, which was acquired July 1, 2007, added $0.2 million to field costs. Expense related to our stock appreciation rights plan decreased by $0.6 million between the periods. The remaining $0.2 million increase in costs resulted from small increases in other costs to operate our crude oil truck fleet.

Six Months Ended June 30, 2008 as Compared to Six Months Ended June 30, 2007

The portions of our supply and logistics operations acquired in the Davison transaction added approximately $10.6 million to our supply and logistics segment margin for the six months ended June 30, 2008. Our historic crude oil operations provided an increase to supply and logistics segment margin of $2.1 million. As in the quarterly periods, grade differentials and volumetric gains provided most of the increase in segment margin from our traditional crude oil operations.

Between the six month periods, field operating costs in our crude oil operations increased $1.4 million, with $0.9 million of that increase attributable to higher fuel prices. Compensation costs to operate the trucks and manage our crude oil gathering operations increased $0.3 million, as a result of compensation increases. Repairs to trucks and equipment, including regulatory testing of our Port Hudson terminal facility, accounted for $0.9 million increase in costs. Expense related to our stock appreciation rights plan decreased between the periods by $0.9 million. The remaining increase in costs of $0.2 million was attributable to numerous factors.

Supply and Logistics Operations Acquired from the Davison Family

Significant factors affecting the operations of the Davison assets include the availability of products for our use in blending to a quality that meets the requirements of our customers and the costs of the transportation services we provide. A key factor influencing our transportation services is the price of diesel for operating our trucks. We use over one million gallons of diesel fuel per quarter. While we include fuel price adjustments in the pricing for many of our transportation services to third parties, we can experience timing differences between when we pay higher prices for the fuel and when we are able to pass that cost through to our customers.

These operations added $3.6 million and $7.0 million to our supply and logistics operations in the first and second quarters of 2008, for a total of $10.6 million in 2008. The significant improvement in the segment margin contribution between the quarters was primarily a result of an improvement in the availability of products for blending and an improvement in the ability of river barges to access our terminals and product supplies for our customers. We utilize our terminal assets to maximize our refined products activities. Because of river flooding on the Red River and other rivers connected to the Mississippi River system during the first quarter of 2008, our customers were limited in their ability to access our product supply. In the second quarter of 2008, river levels returned to normal and barge loading became more consistent.

Market Volatility

As a result of recent volatility in crude oil markets, we wanted to reiterate the risk management practices of our supply and logistics segment. Our risk management policy requires that, with limited specific exceptions, our transactions be balanced (back-to-back) purchases and sales. We experience limited commodity risk, because our risk management practices help limit our exposure to price fluctuations. Our policies require us to hedge inventory above certain base levels needed for operations, and our policies and procedures are consistently monitored, with daily reports reviewed by persons not directly involved in the supply and logistics operations.

We use derivatives as an effective element of our risk management strategy that, while not always meeting accounting requirements to be treated as hedges for financial reporting, help reduce our exposure to market price fluctuations. The use of derivatives is limited to managing or effecting balanced purchase and sales or otherwise managing commodity risk with respect to physical inventory. As discussed in Note 15, for financial accounting and reporting purposes, these derivative instruments that are not treated as hedges are reflected in our Unaudited Consolidated Balance Sheets at fair value and changes in fair value are reflected in our earnings as unrealized gains and losses. These derivative instruments consist almost exclusively of futures and options contracts on the New York Mercantile Exchange (NYMEX) financial market.

Index

Like any participant in the commodities markets, we post margin or receive margin related to our hedging instruments on a daily basis, depending on the fluctuations in the prices of the commodities underlying the hedging instruments. At June 30, 2008 and July 31, 2008, our margin balance requirement including initial margin requirements totaled less than $1.0 million. During the past year while we have owned the Davison assets, our margin requirement has not exceeded $1.5 million.

Additionally, we regularly review the credit standing of our customers. When circumstances warrant, we will require our customers to provide us with credit support in the form of letters of credit, prepayments or right of offset.

Other Costs, Interest, and Income Taxes

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Expenses excluding bonus expense and effects of stock appreciation rights plan	$ 7,755	$ 2,650	$ 15,729	$ 5,189
Bonus plan expense	1,284	433	2,447	879
Stock appreciation rights plan expense (credit)	127	2,517	(486)	2,860
Total general and administrative expenses	$ 9,166	$ 5,600	$ 17,690	$ 8,928

Between the second quarter periods, general and administrative expenses increased by $3.6 million. This increase resulted from an increase related to the administrative personnel and costs at the Davison locations totaling $2.8 million, offset partially by a reduction in general and administrative expense for our stock appreciation rights plan that resulted in a total reduction in expense between the periods of $2.4 million. Bonus plan expense increased $0.9 million between the two periods due to the additional personnel from the Davison acquisition. The remaining change in general and administrative expenses totals $2.3 million. Substantially all of this increase is due to additional fees for audit, tax and other consulting services.

For the six-month periods, general and administrative expenses increased $8.8 million, with $5.3 million attributable to the Davison locations and $1.6 million related to the bonus plan. Our stock appreciation rights plan expense between the periods varied by $3.3 million primarily due to the change in our common unit price from the beginning to the end of each six-month period. From December 31, 2006 to June 30, 2007, our unit price increased by $15.40 per unit whereas in the 2008 period, the unit price decreased by $5.05 per unit. Other changes in general and administrative expenses relating primarily to additional fees for professional services and personnel increase in our corporate offices totaled $5.2 million.

Depreciation and amortization expense. Depreciation and amortization expense increased in the second quarter and six month periods primarily as a result of the depreciation and amortization expense recognized on the fixed and intangible assets acquired in the Davison and Port Hudson transactions. Depreciation and amortization totaled $16.7 million for the second quarter and $33.5 million for the six months.

The intangibles acquired in the Davison acquisition are being amortized over the period during which the intangible asset is expected to contribute to our future cash flows. As intangible assets such as customer relationships and trade names are generally most valuable in the first years after an acquisition, the amortization we will record on these assets will be greater in the initial years after the acquisition. As a result, we expect to record significantly more amortization expense related to our intangible assets in 2008 through 2010 than in years subsequent to that time. See Note 7 to the Unaudited Consolidated Financial Statements for information on the amount of amortization we expect to record in each of the next five years.

Index

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Interest expense, including commitment fees	$ 2,039	$ 289	$ 3,713	$ 498
Capitalized interest	(48)	-	(101)	(6)
Amortization of facility fees	165	66	330	133
Interest income	(117)	(34)	(234)	(78)
Net interest expense	$ 2,039	$ 321	$ 3,708	$ 547

The Davison acquisition was partially financed with borrowings under our credit facility beginning on July 25, 2007. In December 2007, we reduced our debt with an equity offering. On May 30, 2008, we increased our debt to fund the drop-down transactions. As a result of these debt changes, our average outstanding debt balance increased $154.8 million over the average outstanding debt balance in the second quarter of 2007. The average interest rate on our debt during the 2008 quarter was 4.4% lower. The combination of these changes was the primary factor in an increase in net interest expense between the second quarter periods of $1.7 million. For the six month periods, average outstanding debt was $113.5 million greater in the 2008 period and our average interest rate was 3.9% less. Net interest expense for the six month periods increased $3.2 million.

Income taxes.

Only a small portion of the operations we acquired in the Davison transaction are owned by wholly-owned corporate subsidiaries that are taxable as corporations. As a result, the income tax expense we record relates only to the operations of those corporations, and will vary from period to period as a percentage of our income before taxes based on the percentage of our income or loss that is derived from those corporations. In the 2008 second quarter and six-month periods, we recorded an income tax benefit related to the operations of those corporations.

New and Proposed Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2, “Recent Accounting Developments” in the accompanying unaudited 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 the nega 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," sodium hydrosulfide and caustic soda 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;

Index

- 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;
- shutdowns 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;
- 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, 2007. 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 various market risks, primarily related to volatility in crude oil and petroleum products prices, NaOH prices, and interest rates. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the segment margin we receive. We do not acquire and hold futures contracts or other derivative products for the purpose of speculating on price changes, as these activities could expose us to significant losses.

Our primary price risk relates to the effect of crude oil and petroleum products price fluctuations on our inventories and the fluctuations each month in grade and location differentials and their effect on future contractual commitments. Our risk management policies are designed to monitor our physical volumes, grades, and delivery schedules to ensure our hedging activities address the market risks that are inherent in our gathering and marketing activities.

We utilize NYMEX commodity based futures contracts and option contracts to hedge our exposure to these market price fluctuations as needed. All of our open commodity price risk derivatives at June 30, 2008 were categorized as non-trading. On June 30, 2008, we had entered into NYMEX future contracts that settled during July 2008 and NYMEX options contracts that settled during July 2008. Although the intent of our risk-management activities is to hedge our margin, none of our derivative positions at June 30, 2008 qualified for hedge accounting.

The table below presents information about our open derivative contracts at June 30, 2008. Notional amounts in barrels, the weighted average contract price, total contract amount, and total fair value amount in U.S. dollars of our open positions are presented below. Fair values were determined by using the notional amount in barrels multiplied by the June 30, 2008 quoted market prices on the NYMEX. All of the hedge positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the table below.

This accounting treatment is discussed further under Note 2 “Summary of Significant Accounting Policies” of our Consolidated Financial Statements in our 2007 Annual Report on Form 10-K. Also see Notes 15 and 18 to the Unaudited Consolidated Financial Statements for additional information on our derivative transactions and fair value measurements of those derivatives.

Index

		Sell (Short) Contracts		Buy (Long) Contracts
Futures Contracts:				
Crude Oil:				
Contract volumes (1,000 bbls)		128		66
Weighted average price per bbl	$	135.00	$	136.40
Contract value (in thousands)	$	17,280		9,002
Mark-to-market change (in thousands)		640		238
Market settlement value (in thousands)	$	17,920	$	9,240

NYMEX Option Contracts:		Sell (Short) Contracts
Crude Oil- Written Calls		
Contract volumes (1,000 bbls)		47
Weighted average premium received	$	6.05
Contract value (in thousands)	$	284
Mark-to-market change (in thousands)		(40)
Market settlement value (in thousands)	$	244
Natural Gas-Written Calls		
Contract volumes (10,000 mmBtus)		12
Weighted average premium received	$	6.16
Contract value (in thousands)	$	74
Mark-to-market change (in thousands)		31
Market settlement value (in thousands)	$	105
Natural Gas-Written Puts		
Contract volumes (10,000 mmBtus)		5
Weighted average premium received	$	3.48
Contract value (in thousands)	$	17
Mark-to-market change (in thousands)		(4)
Market settlement value (in thousands)	$	13

Index

We manage our risks of volatility in NaOH prices by indexing prices for the sale of NaHS to the market price for NaOH in most of our contracts.

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, at our option, plus the applicable margin. We do not hedge our interest rates. The carrying values of our debt approximate fair value primarily because interest rates fluctuate with prevailing market rats, and the credit spread on outstanding borrowings reflect market. On June 30, 2008, we had $319.0 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.

Davison Acquisition

On July 25, 2007, we completed the Davison Acquisition, which met the criteria of being a significant acquisition for us. For additional information regarding the acquisition, please read Note 3 to the Unaudited Consolidated Financial Statements included in Item 1 in this Quarterly Report on Form 10-Q.

On June 22, 2004, the Office of the Chief Accountant of the SEC issued guidance regarding the reporting of internal control over financial reporting in connection with a major acquisition. On October 6, 2004, the SEC revised its guidance to include expectations of quarterly reporting updates of new internal control and the status of the control regarding any exempted businesses. This guidance was reiterated in September 2007 to affirm that management may omit an assessment of an acquired business' internal control over financial reporting from management's assessment of internal control over financial reporting for a period not to exceed one year.

We excluded the operations acquired in the Davison Acquisition from the scope of our Sarbanes-Oxley Section 404 report on internal control over financial reporting for the year ended December 31, 2007. A summary of the reasons for this exclusion is under Item 9A of our 2007 Annual Report on Form 10-K.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I. Item 1. See Note 16 of the Notes to the Unaudited 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, 2007. In addition, we believe that the following additional risk factor is relevant for our investment in DG Marine, which acquired the inland marine transportation business of Grifco Transportation, Ltd. in July 2008.

Our investment in DG Marine Transportation, LLC (DG Marine) exposes us to certain risks that are inherent to the barge transportation industry as well certain risks applicable to our other operations.

DG Marine's inland barge transportation business has exposure to certain risks which are significant to our other operations and certain risks inherent to the barge transportation industry. For example, unlike our other operations, DG Marine operates barges that transport products to and from numerous marine locations, which exposes us to new risks, including:

Index

being subject to the Jones Act and other federal laws that restrict U.S. maritime transportation to vessels built and registered in the U.S. and owned and manned by U.S. citizens, with any failure to comply with such laws potentially resulting in severe penalties, including permanent loss of U.S. coastwise trading rights, fines or forfeiture of vessels;

relying on a limited number of customers;

having primarily short-term charters which DG Marine may be unable to renew as they expire; and

competing against businesses with greater financial resources and larger operating crews than DG Marine.

In addition, like our other operations, DG Marine's refined products transportation business is an integral part of the energy industry infrastructure, which increases our exposure to declines in demand for refined petroleum products or decreases in U.S. refining activity.

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

On June 4, 2008, we issued 1,199,041 of our common units to Denbury Onshore. The units were issued at a value of $20.85 per unit, for a total value of $25 million as a portion of the consideration for the acquisition of the Free State Pipeline in Mississippi. As a result of that purchase, our general partner and its affiliates will hold 10.2% of our outstanding common units. This issuance of common units by us was completed on June 4, 2008 and was exempt from registration under the Securities Act of 1933 by reason of Section 4(2) thereof and Rule 506 of Regulation D promulgated thereunder.

See Note 3, 10 and 12 of the Notes to the Unaudited Consolidated Financial Statements.

On July 18, 2008, we redeemed 837,690 of our common units owned by members of the Davison family. Those units had been issued as a portion of the consideration for the acquisition of the energy-related business of the Davison family in July 2007. The redemption was at a value of $19.896 per unit, for a total value of $16.7 million.

Additionally, on July 18, 2008, we issued 837,690 of our common units to Grifco. Those units were issued at a value of $19.896 per unit, for a total value of $16.7 million as a portion of the consideration for our investment in DG Marine, which acquired the inland marine transportation business of Grifco. That issuance of common units by us was completed on July 18, 2008 and was exempt from registration under the Securities Act of 1933 by reason of Section 4(2) thereof and Rule 506 of Regulation D promulgated thereunder. After giving effect to the issuance and redemption described above, we did not experience a change in the number of common units it has outstanding.

See Note 3 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.

3.1	Certificate of Limited Partnership of Genesis Energy, L.P. (“Genesis”) (incorporated by reference to Exhibit 3.1 to Registration Statement, File No. 333-11545)
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 4.1 to Form 8-K dated June 15, 2005)
3.3	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 3.3 to Form 10-K for the year ended December 31, 2007.)

Index

3.4		Certificate of Limited Partnership of Genesis Crude Oil, L.P. (“the Operating Partnership”) (incorporated by reference to Exhibit 3.3 to Form 10-K for the year ended December 31, 1996)
3.5		Fourth Amended and Restated Agreement of Limited Partnership of the Operating Partnership (incorporated by reference to Exhibit 4.2 to Form 8-K dated June 15, 2005)
3.6		Certificate of Incorporation of Genesis Energy, Inc. (incorporated by reference to Exhibit 3.6 to Form 10-K for the year ended December 31, 2007.)
3.7		Certificate of Amendment of Certificate of Incorporation of Genesis Energy, Inc. (incorporated by reference to Exhibit 3.7 to Form 10-K for the year ended December 31, 2007.)
3.8		Bylaws of Genesis Energy, Inc. (incorporated by reference to Exhibit 3.8 to Form 10-K for the year ended December 31, 2007.)
4.1		Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2007.)
10.1		Pipeline Financing Lease Agreement by and between Genesis NEJD Pipeline, LLC, as Lessor and Denbury Onshore, LLC, as Lessee for the North East Jackson Dome Pipeline dated May 30, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K dated June 5, 2008.)
10.2		Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Free State Pipeline, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K dated June 5, 2008.)
10.3		Transportation Services Agreement between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K dated June 5, 2008.)
10.4		First Amended and Restated Credit Agreement dated as of May 30, 2008 among Genesis Crude Oil, L.P., Genesis Energy, L.P., the Lenders Party Hereto, Fortis Capital Corp., and Deutsche Bank Securities Inc. (incorporated by reference to Exhibit 10.4 to Form 8-K dated June 5, 2008.)
31.1	*	Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.
31.2	*	Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.
32	*	Certification by Chief Executive Officer and Chief Financial Officer Pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934.

*Filed herewith

Index

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 8, 2008

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