GENESIS ENERGY LP
Form 10-Q
August 07, 2009

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, 2009

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	76-0513049
(State or other jurisdictions of incorporation or organization)	(I.R.S. Employer Identification No.)
919 Milam, Suite 2100, Houston, TX	77002
(Address of principal executive offices)	(Zip code)
Registrant's telephone number, including area code:	(713) 860-2500

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

NONE

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files).

Yes £ No £

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

Large accelerated filer £ 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 7, 2009: 39,479,774

GENESIS ENERGY, L.P.

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

	June 30, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$6,929	$18,985
Accounts receivable - trade, net of allowance for doubtful accounts of $1,554 and $1,132 at June 30, 2009 and December 31, 2008, respectively	118,325	112,229
Accounts receivable - related party	2,376	2,875
Inventories	38,594	21,544
Net investment in direct financing leases, net of unearned income -current portion - related party	3,975	3,758
Other	12,674	8,736
Total current assets	182,873	168,127
FIXED ASSETS, at cost	371,406	349,212
Less: Accumulated depreciation	(78,524)	(67,107)
Net fixed assets	292,882	282,105
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	175,163	177,203
CO2 ASSETS, net of amortization	22,350	24,379
EQUITY INVESTEES AND OTHER INVESTMENTS	20,857	19,468
INTANGIBLE ASSETS, net of amortization	152,989	166,933
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	15,922	15,413
TOTAL ASSETS	$1,188,082	$1,178,674
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$98,821	$96,454
Accounts payable - related party	3,199	3,105
Accrued liabilities	23,415	26,713
Total current liabilities	125,435	126,272
LONG-TERM DEBT	399,400	375,300
DEFERRED TAX LIABILITIES	17,030	16,806
OTHER LONG-TERM LIABILITIES	3,169	2,834
COMMITMENTS AND CONTINGENCIES (Note 17)		
PARTNERS' CAPITAL:		
Common unitholders, 39,480 and 39,457 units issued and outstanding,respectively	603,263	616,971

General partner	16,364	16,649
Accumulated other comprehensive loss	(863)	(962)
Total Genesis Energy, L.P. partners' capital	618,764	632,658
Noncontrolling interests	24,284	24,804
Total partners' capital	643,048	657,462
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$1,188,082	$1,178,674

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

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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,	
	2009	2008	2009	2008
REVENUES:				
Supply and logistics:				
Unrelated parties	$290,236	$568,328	$478,054	$997,721
Related parties	1,128	1,149	2,372	1,874
Refinery services	34,594	55,727	82,888	99,639
Pipeline transportation, including natural gas sales:				
Transportation services - unrelated parties	4,032	5,168	7,433	11,077
Transportation services - related parties	7,904	4,115	16,198	5,167
Natural gas sales revenues	519	1,603	1,232	2,927
CO2 marketing:				
Unrelated parties	3,057	3,693	6,109	6,856
Related parties	734	757	1,411	1,464
Total revenues	342,204	640,540	595,697	1,126,725
COSTS AND EXPENSES:				
Supply and logistics costs:				
Product costs - unrelated parties	266,313	542,200	430,044	949,475
Product costs - related parties	41	-	1,754	-
Operating costs	17,921	17,785	35,190	34,367
Refinery services operating costs	21,218	38,111	56,551	68,435
Pipeline transportation costs:				
Pipeline transportation operating costs	2,638	2,490	5,132	4,846
Natural gas purchases	470	1,568	1,124	2,854
CO2 marketing costs:				
Transportation costs - related party	1,341	1,376	2,648	2,633
Other costs	15	15	31	30
General and administrative	8,306	9,166	17,060	17,690
Depreciation and amortization	16,133	16,721	31,552	33,510
Net loss (gain) on disposal of surplus assets	60	76	(158)	94
Total costs and expenses	334,456	629,508	580,928	1,113,934
OPERATING INCOME	7,748	11,032	14,769	12,791
Equity in earnings (losses) of joint ventures	264	(16)	2,170	162
Interest income	16	117	37	234
Interest expense	(3,389)	(2,156)	(6,445)	(3,942)
Income before income taxes	4,639	8,977	10,531	9,245
Income tax expense	(817)	(1,648)	(1,408)	(271)
NET INCOME	3,822	7,329	9,123	8,974
Noncontrolling interests	634	(1)	623	(1)

NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$4,456	$7,328	$9,746	$8,973

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:				
BASIC	$0.13	$0.17	$0.29	$0.20
DILUTED	$0.13	$0.17	$0.29	$0.20
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:				
BASIC	39,464	38,675	39,460	38,464
DILUTED	39,618	38,731	39,592	38,514

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

GENESIS ENERGY, L.P.
UNAUDITED CONSOLIDATED STATEMENTS
OF COMPREHENSIVE INCOME
(In thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net income	$3,822	$7,329	$9,123	$8,974
Change in fair value of derivatives:				
Current period reclassification to earnings	158	-	290	-
Changes in derivative financial instruments - interest rate swaps	43	-	(85)	-
Comprehensive income	4,023	7,329	9,328	8,974
Comprehensive income attributable to noncontrolling interests	(103)	-	(106)	-
Comprehensive income attributable to Genesis Energy, L.P.	$3,920	$7,329	$9,222	$8,974

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

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

		Partners' Capital				
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-Controlling Interests	Total Capital
Partners' capital, January 1, 2009	39,457	$616,971	$16,649	$ (962)	$24,804	$657,462
Comprehensive income:						
Net income		12,051	(2,305)		(623)	9,123
Interest rate swap losses reclassified to interest expense				142	148	290
Interest rate swap loss				(43)	(42)	(85)
Cash contributions			6			6
Cash distributions		(26,338)	(2,485)		(3)	(28,826)
Contribution for executive compensation (See Note 12)			4,499			4,499
Unit based compensation expense	23	579				579
Partners' capital, June 30, 2009	39,480	$603,263	$16,364	$ (863)	$24,284	$643,048

		Partners' Capital				
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-Controlling Interests	Total Capital
Partners' capital, January 1, 2008	38,253	$615,265	$16,539	$ -	$570	$632,374
Comprehensive income:						
Net income		8,045	928	-	1	8,974
Cash contributions			510	-	5	515
Cash distributions		(22,378)	(1,131)	-	(2)	(23,511)
Issuance of units	1,199	25,000	-	-	-	25,000
Partners' capital, June 30, 2008	39,452	$625,932	$16,846	$ -	$574	$643,352

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

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

	Six Months Ended June 30,	
	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$9,123	$8,974
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation and amortization	31,552	33,510
Amortization of credit facility issuance costs	961	535
Amortization of unearned income and initial direct costs on direct financing leases	(9,092)	(1,772)
Payments received under direct financing leases	10,927	594
Equity in earnings of investments in joint ventures	(2,170)	(162)
Distributions from joint ventures - return on investment	800	815
Non-cash effect of unit-based compensation plans	5,988	(619)
Deferred and other tax liabilities	1,087	(926)
Other non-cash items	(1,270)	(19)
Net changes in components of operating assets and liabilities (See Note 13)	(28,840)	(18,234)
Net cash provided by operating activities	19,066	22,696
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(26,597)	(9,543)
CO2 pipeline transactions and related costs	-	(228,833)
Distributions from joint ventures - return of investment	-	438
Investments in joint ventures and other investments	(21)	(2,210)
Other, net	578	(846)
Net cash used in investing activities	(26,040)	(240,994)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings	130,300	344,100
Bank repayments	(106,200)	(105,100)
General partner contributions	6	510
Net noncontrolling interest (distributions) contributions	(3)	3
Distributions to common unitholders	(26,338)	(22,378)
Distributions to general partner interest	(2,485)	(1,131)
Other, net	(362)	(370)
Net cash (used in) provided by financing activities	(5,082)	215,634
Net decrease in cash and cash equivalents	(12,056)	(2,664)
Cash and cash equivalents at beginning of period	18,985	11,851
Cash and cash equivalents at end of period	$6,929	$9,187

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

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

1. Organization and Basis of Presentation and Consolidation

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 and carbon dioxide;
- 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);
- Supply and logistics services, which includes terminaling, blending, storing, marketing, and transporting by trucks and barges of crude oil and petroleum products; and
- Industrial gas activities, including wholesale marketing of CO2 and processing of syngas through a joint venture.

Our 2% general partner interest is held by Genesis Energy, LLC, a Delaware limited liability company and an indirect 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 Presentation and Consolidation

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, 2008.

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.

The accompanying unaudited consolidated financial statements and related notes present our consolidated financial position as of June 30, 2009 and December 31, 2008 and our results of operations and changes in comprehensive income for the three and six months ended June 30, 2009 and 2008, and cash flows and changes in partners' capital for the six months ended June 30, 2009 and 2008. 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.

We participate in three joint ventures: DG Marine Transportation, LLC (DG Marine), T&P Syngas Supply Company (T&P Syngas) and Sandhill Group, LLC (Sandhill). We acquired our interest in DG Marine in July 2008, and, since then DG Marine has been consolidated in our financial statements. We account for our 50% investments in T&P Syngas and Sandhill by the equity method of accounting.

Our general partner owns a 0.01% general partner interest in Genesis Crude Oil, L.P. and TD Marine, LLC (TD Marine), a related party, owns the remaining 51% economic interest in DG Marine. The net interest of our general partner and TD Marine in our results of operations and financial position are reflected in our financial statements as noncontrolling interests.

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NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

Subsequent Events

We have considered subsequent events through August 7, 2009, the date of issuance, in preparing the consolidated financial statements and notes thereto.

2. Recent Accounting Developments

Implemented

SFAS 165

In May 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 165, "Subsequent Events". SFAS 165 establishes the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. See "Subsequent Events" included in "Note 1 – Organization and Basis of Presentation and Consolidation" for the related disclosure. The provisions of SFAS 165 are being applied prospectively beginning in the second quarter of 2009 and did not have a material impact on our consolidated financial statements.

FASB Staff Position No 107-1 and APB 28-1

In April 2009, the FASB issued FASB Staff Position No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments" ("FSP 107-1"). FSP 107-1 requires fair value disclosures on an interim basis for financial instruments that are not reflected in the consolidated balance sheets at fair value. Prior to the issuance of FSP 107-1, the fair values of those financial instruments were only disclosed on an annual basis. We adopted FSP 107-1for our quarter ended June 30, 2009, and it did not have a material impact on our consolidated financial statements.

SFAS 141(R)

In December 2007, the FASB issued SFAS No. 141(R) "Business Combinations." 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) will apply to acquisitions we make after December 31, 2008. The impact to us will be dependent on the nature of the business combination.

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 adopted SFAS 160 on January 1, 2009. SFAS 160 changed the presentation of the interests in Genesis Crude Oil, L.P. held by our general partner and the interests in DG Marine held by our joint venture partner in our consolidated financial statements. Amounts for prior periods have been changed to be consistent with the presentation required by SFAS 160.

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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 adopted SFAS No. 161 on January 1, 2009, and have included the enhanced disclosures in Note 15.

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 (for purposes of calculating earnings or loss per unit) 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 (for purposes of calculating earnings or loss per unit) 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 adopted EITF 07-4 on January 1, 2009 and have reflected the calculation of earnings per unit for the three and six months ended June 30, 2009 and 2008 in accordance with its provisions. See Note 9.

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 adopted FSP 142-3 on January 1, 2009 and adoption had no effect on our consolidated financial statements.

SFAS 157

We adopted SFAS No. 157, "Fair Value Measurements" (SFAS 157), on January 1, 2008. On February 12, 2008 the 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, to January 1, 2009. Non-recurring non-financial assets and non-financial liabilities for which we did not apply the provisions of SFAS 157 included those measured at fair value in goodwill impairment testing and asset retirement obligations initially measured at fair value. We adopted the deferred provisions as of January 1, 2009. 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. The adoption of FSP 157-2 as described above had no material impact on us. See Note 16 for further information regarding fair-value measurements.

3. Consolidated Joint Venture – DG Marine

DG Marine is a joint venture we formed with TD Marine. TD Marine owns (indirectly) a 51% economic interest in DG Marine, and we own (directly and indirectly) a 49% economic interest. This joint venture gives us the capability to provide transportation services of petroleum products by barge and complements our other supply and logistics operations.

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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 a rate to be determined which is expected to be the prime rate plus 4%. 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 also has a revolving credit facility with a syndicate of financial institutions that includes restrictions on DG Marine's ability to make specified payments under our subordinated loan agreement and distributions in respect of our equity interest. At June 30, 2009, $13 million was outstanding under the subordinated loan agreement; however this amount was eliminated in consolidation. At December 31, 2008, there were no amounts outstanding under the subordinated loan agreement.

At June 30, 2009 and December 31, 2008, our unaudited consolidated balance sheets included the following amounts related to DG Marine:

	June 30, 2009	December 31, 2008
Cash	$-	$623
Accounts receivable - trade	2,753	2,812
Other current assets	94	859
Fixed assets, at cost	125,211	110,214
Accumulated depreciation	(6,001)	(3,084)
Intangible assets, net	1,983	2,208
Other assets	1,749	2,178
Total assets	$125,789	$115,810
Accounts payable	$1,025	$1,072
Accrued liabilities	9,779	9,258
Long-term debt	53,100	55,300
Other long-term liabilities	976	1,393
Total liabilities	$64,880	$67,023

4. Inventories

Inventories are valued at the lower of cost or market. The costs of inventories did not exceed market values at June 30, 2009. The costs of inventories at December 31, 2008 exceeded market values by approximately $1.2 million, and are reflected below at those market values. The major components of inventories were as follows:

	June 30, 2009	December 31, 2008
Crude oil	17,606	1,878
Petroleum products	15,528	5,589
Caustic soda	2,371	7,139
NaHS	3,067	6,923
Other	22	15
Total inventories	$38,594	$21,544

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NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

5. Fixed Assets and Asset Retirement Obligations

Fixed assets consisted of the following:

	June 30, 2009	December 31, 2008
Land, buildings and improvements	$13,609	$13,549
Pipelines and related assets	152,598	139,184
Machinery and equipment	24,553	22,899
Transportation equipment	33,173	32,833
Barges and push boats	123,847	96,865
Office equipment, furniture and fixtures	4,616	4,401
Construction in progress	6,361	27,906
Other	12,649	11,575
Subtotal	371,406	349,212
Accumulated depreciation and impairment	(78,524)	(67,107)
Total	$292,882	$282,105

Depreciation expense was $7.8 million and $15.2 million for the three and six months ended June 30, 2009 and 2008, respectively. For the three and six months ended June 30, 2008, depreciation expense was $5.1 million and $10.3 million, respectively.

Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the six months ended June 30, 2009.

Asset retirement obligations as of December 31, 2008	$1,430
Liabilities incurred and assumed in the period	726
Liabilities settled in the period	(75)
Accretion expense	49
Asset retirement obligations as of June 30, 2009	2,130
Less current portion included in accrued liabilities	(150)
Long-term asset retirement obligations as of June 30, 2009	$1,980

Certain of our unconsolidated affiliates have asset retirement obligations recorded at June 30, 2009 and December 31, 2008 relating to contractual agreements. These amounts are immaterial to our financial statements.

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

6. Intangible Assets and Goodwill

Intangible Assets

The following table reflects the components of intangible assets being amortized at the dates indicated:

		June 30, 2009			December 31, 2008		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Customer relationships:							
Refinery services	5	$ 94,654	$ 33,734	$ 60,920	$ 94,654	$ 26,017	$ 68,637
Supply and logistics	5	35,430	12,725	22,705	35,430	9,957	25,473
Supplier relationships -							
Refinery services	2	36,469	26,517	9,952	36,469	24,483	11,986
Licensing Agreements -							
Refinery services	6	38,678	9,428	29,250	38,678	7,176	31,502
Trade names -							
Supply and logistics	7	18,888	4,281	14,607	18,888	3,118	15,770
Favorable lease -							
Supply and logistics	15	13,260	908	12,352	13,260	671	12,589
Other	5	3,822	619	3,203	1,322	346	976
Total	5	$ 241,201	$ 88,212	$ 152,989	$ 238,701	$ 71,768	$ 166,933

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 $8.3 million and $16.4 million for the three and six months ended June 30, 2009, respectively. Amortization expense on intangible assets was $11.6 million and $23.2 million for the three and six months ended June 30, 2008, respectively.

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 2009	$ 16,656
2010	$ 26,635
2011	$ 21,918
2012	$ 18,261
2013	$ 14,264
2014	$ 11,790

Goodwill

The carrying amount of goodwill by business segment at June 30, 2009 and December 31, 2008 was $302.0 million to refinery services and $23.1 million to supply and logistics.

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7. Equity Investees and Other Investments

T&P Syngas Supply Company

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 $0.8 million and $1.1 million during the six months ended June 30, 2009 and 2008, respectively. During the first quarter of 2009, “Equity in earnings of joint ventures” included $1.7 million of non-cash items related to T&P Syngas that increased earnings.

The tables below reflect summarized information for T&P Syngas:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues	$986	$1,224	$2,151	$2,433
Operating expenses and depreciation	(524)	(365)	(1,098)	(732)
Other income (expense)	5	22	13	15
Net income	$467	$881	$1,066	$1,716

	June 30, 2009	December 31, 2008
Current assets	$ 3,468	$ 3,131
Non-current assets	18,139	18,906
Total assets	$ 21,607	$ 22,037
Current liabilities	$ 637	$ 543
Non-current liabilities	208	198
Partners' capital	20,762	21,296
Total liabilities and partners' capital	$ 21,607	$ 22,037

8. Debt

At June 30, 2009, our obligations under credit facilities consisted of the following:

	June 30, 2009	December 31, 2008
Genesis Credit Facility	$346,300	$320,000
DG Marine Credit Facility	53,100	55,300
Total Long-Term Debt	$399,400	$375,300

Genesis Credit Facility

We have a $500 million credit facility, $100 million of which can be used for letters of credit, with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. Due to the revolving nature of loans under our credit facility, we may repay and re-borrow amounts until the maturity date of November 15, 2011. Our borrowing base is recalculated quarterly and at the time of material acquisitions. Our borrowing base represents the amount that we can borrow or utilize for letters of credit, and it is calculated based on our EBITDA (earnings before interest, taxes, depreciation and amortization), as defined in accordance with the provisions of our credit facility. Our 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.

As of June 30, 2009, our borrowing base exceeded $500 million, and we had $346.3 million borrowed and $4.4 million in letters of credit outstanding. Thus, our total remaining availability at June 30, 2009 was $149.3 million under our credit facility. Effective August 14, 2009, our borrowing base will decrease to $419 million as a result of changes in covenant requirements beginning in the period after the one-year anniversary of a material acquisition and changes in our EBITDA.

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DG Marine Credit Facility

DG Marine has a $90 million revolving credit facility with a syndicate of banks led by SunTrust Bank and BMO Capital Markets Financing, Inc. That facility, which matures on July 18, 2011, is secured by all of the equity interests issued by DG Marine and substantially all of DG Marine's assets. Other than the pledge of our equity interest in DG Marine, that facility is non-recourse to us and TD Marine. At June 30, 2009, our Unaudited Consolidated Balance Sheet included $125.8 million of DG Marine's assets in our total assets.

At June 30, 2009, DG Marine had $53.1 million outstanding under its credit facility. Although the total amount available for borrowings at June 30, 2009 was $36.9 million under this credit facility, we do not anticipate utilizing this availability for working capital needs.

In August 2008, DG Marine entered into a series of interest rate swap agreements to effectively fix the underlying LIBOR rate on $32.9 million of its borrowings under its credit facility through July 18, 2011. The fixed interest rates in the swap agreements range from the three-month interest rate of 3.37% in effect at June 30, 2009 to 4.68% at July 18, 2011.

We have estimated the total fair value of our long-term debt under our credit agreement and the DG Marine credit facility to be approximately $384.3 million, or $15.1 million less than the carrying value of that debt.

9. Partners' Capital and Distributions

Partners' Capital

Partner's capital at June 30, 2009 consists of 39,479,774 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 effect to the general partner interest), and a 2% general partner interest.

Our general partner owns all of our general partner interest, our incentive distribution rights, and all of the 0.01% general partner interest in Genesis Crude Oil, L.P. (which is reflected as a noncontrolling interest in our Unaudited Consolidated Balance Sheets) and operates our business.

Without obtaining unitholder approval, we may issue an unlimited number of 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

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.

Pursuant to our partnership agreement, our general partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds. The allocations of distributions between our common unitholders and our general partner (including its general partner interest and the incentive distribution rights) are 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	74.53%	25.47%
Over Second Target - Cash distributions greater than $.033 per Unit	49.02%	50.98%

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We paid or will pay the following distributions in 2008 and 2009:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
First quarter 2008	May 2008	$ 0.3000	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009 (1)	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326

(1) This distribution will be paid on August 14, 2009 to our general partner and unitholders of record as of August 4, 2009.

Net Income Allocation to Partners

Net income is allocated to our partners in the Consolidated Statements of Partners' Capital as follows:

- To our general partner – income in the amount of the incentive distributions paid in the period.
- To our general partner – expense in the amount of the executive compensation expense to be borne by our general partner (See Note 12).
- To our limited partners and general partner – the remainder of net income in the ratio of 98% to the limited partners and 2% to our general partner.

Net Income Per Common Unit

Our net income is first allocated to our general partner based on the amount of incentive distributions to be paid for the quarter. The adoption of EITF 07-4 effective January 1, 2009 resulted in a change in the calculation of net income per common unit by changing the amount of the incentive distributions to be considered in the calculation from the distributions paid during the quarter to the distributions to be paid with respect to the quarter. As required by EITF 07-4, we have retrospectively applied the provisions of EITF 07-4 to the calculation of net income per common unit for the first quarter of 2008 in the table below. As a result, basic and diluted net income per common unit remained the same as compared to amounts previously reported for the three month ended June 30, 2008 and decreased by $0.01 from the amount previously reported for the six months ended June 30, 2008.

We then allocate to our general partner the expense related to the Class B Membership Awards to our executive officers, as our general partner will bear the cash cost of those awards. The remainder of our net income is then allocated 98% to our limited partners and 2% to our 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. (See Note 12 for discussion of phantom units.)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Numerators for basic and diluted net income per common unit:				
Net income attributable to Genesis Energy, L.P.	$4,456	$7,328	$9,746	$8,973
Less: General partner's incentive distribution to to be paid for the period	(1,427)	(633)	(2,552)	(1,062)
Add: Expense for Class B Membership Awards (Note 12)	2,353	-	4,499	-
Subtotal	5,382	6,695	11,693	7,911
Less: General partner 2% ownership	(108)	(134)	(234)	(158)
Income available for common unitholders	$5,274	$6,561	$11,459	$7,753
Denominator for basic per common unit:				
Common Units	39,464	38,675	39,460	38,464
Denominator for diluted per common unit:				
Common Units	39,464	38,675	39,460	38,464
Phantom Units	154	56	132	50
	39,618	38,731	39,592	38,514
Basic net income per common unit	$0.13	$0.17	$0.29	$0.20
Diluted net income per common unit	$0.13	$0.17	$0.29	$0.20

10. Business Segment Information

Our operations consist of four operating segments: (1) Pipeline Transportation – interstate and intrastate crude oil and CO2; (2) Refinery Services – processing high sulfur (or "sour") gas streams as part of refining operations to remove the sulfur and selling the related by-product; (3) Supply and Logistics – terminaling, blending, storing, marketing, gathering and transporting by truck and barge crude oil and petroleum products, and (4) Industrial Gases – the sale of CO2 acquired under volumetric production payments to industrial customers and our investment in a syngas processing facility. Substantially all of our revenues are derived from, and substantially all of our assets are located in the United States.

During the fourth quarter of 2008, we revised the manner in which we internally evaluate our segment performance. As a result, we changed our definition of segment margin to include within segment margin all costs that are directly associated with the business segment. Segment margin now includes costs such as general and administrative expenses that are directly incurred by the business segment. Segment margin also includes all payments received under direct financing leases. In order to improve comparability between periods, we exclude from segment margin the non-cash effects of our stock-based compensation plans which are impacted by changes in the market price for our common units. Segment information for the three and six months ended June 30, 2008 has been retrospectively revised to conform to this segment presentation. We now define segment margin as revenues less cost of sales, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. Our segment margin definition also excludes the non-cash effects of our stock-based compensation plans, and includes the non-income portion of payments received under direct financing leases. 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.

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	Pipeline Transportation	Refinery Services	Supply & Logistics	Industrial Gases (a)	Total
Three Months Ended June 30, 2009					
Segment margin (b)	$ 10,347	$13,190	$6,600	$ 2,869	$33,006
Maintenance capital expenditures	$ 476	$51	$947	$ -	$1,474
Revenues:					
External customers	$ 10,883	$35,923	$291,607	$ 3,791	$342,204
Intersegment (d)	1,572	(1,329)	(243)	-	-
Total revenues of reportable segments	$ 12,455	$34,594	$291,364	$ 3,791	$342,204
Three Months Ended June 30, 2008					
Segment margin (b)	$ 7,261	$16,279	$7,780	$ 3,686	$35,006
Maintenance capital expenditures	$ -	$208	$-	$ -	$208
Revenues:					
External customers	$ 8,885	$55,727	$571,478	$ 4,450	$640,540
Intersegment (d)	2,001	-	(2,001)	-	-
Total revenues of reportable segments	$ 10,886	$55,727	$569,477	$ 4,450	$640,540

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	Pipeline Transportation	Refinery Services	Supply & Logistics	Industrial Gases (a)	Total
Six Months Ended June 30, 2009					
Segment margin (b)	$ 20,572	$25,949	$12,556	$ 5,892	$64,969
Capital expenditures (c)	$ 2,458	$1,982	$21,497	$ 21	$25,958
Maintenance capital expenditures	$ 750	$544	$1,128	$ -	$2,422
Revenues:					
External customers	$ 22,198	$85,828	$480,151	$ 7,520	$595,697
Intersegment (d)	2,665	(2,940)	275	-	-
Total revenues of reportable segments	$ 24,863	$82,888	$480,426	$ 7,520	$595,697
Six Months Ended June 30, 2008					
Segment margin (b)	$ 11,922	$28,709	$11,841	$ 6,885	$59,357
Capital expenditures (c)	$ 78,524	$1,710	$4,603	$ 2,210	$87,047
Maintenance capital expenditures	$ 165	$489	$330	$ -	$984
Revenues:					
External customers	$ 15,673	$99,639	$1,003,093	$ 8,320	$1,126,725
Intersegment (d)	3,498	-	(3,498)	-	-
Total revenues of reportable segments	$ 19,171	$99,639	$999,595	$ 8,320	$1,126,725

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

b) A reconciliation of segment margin to income before income taxes and noncontrolling interests for the periods presented is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Segment margin	$33,006	$35,006	$64,969	$59,357
Corporate general and administrative expenses	(7,576)	(5,757)	(15,077)	(10,986)
Depreciation and amortization	(16,133)	(16,721)	(31,552)	(33,510)
Net (loss) gain on disposal of surplus assets	(60)	(76)	158	(94)
Interest expense, net	(3,373)	(2,039)	(6,408)	(3,708)
Non-cash expenses not included in segment margin	(126)	(396)	(842)	(204)
Other non-cash items affecting segment margin	(1,099)	(1,040)	(717)	(1,610)
Income before income taxes	$4,639	$8,977	$10,531	$9,245

c) Capital expenditures include fixed asset additions and acquisitions of businesses.

d) Intersegment sales were conducted on an arm's length basis.

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11. 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, 2009		Six Months Ended June 30, 2008	
		2009		2008
Truck transportation services provided to Denbury	$	1,982	$	1,220
Pipeline transportation services provided to Denbury	$	7,047	$	3,314
Payments received under direct financing leases from Denbury	$	10,927	$	594
Pipeline transportation income portion of direct financing lease fees	$	9,191	$	1,798
Pipeline monitoring services provided to Denbury	$	60	$	48
Directors' fees paid to Denbury	$	110	$	101
CO2 transportation services provided by Denbury	$	2,507	$	2,632
Crude oil purchases from Denbury	$	1,754	$	-
Operations, general and administrative services provided by our general partner	$	27,645	$	25,789
Distributions to our general partner on its limited partner units and general partner interest, including incentive distributions	$	4,374	$	2,786
Sales of CO2 to Sandhill	$	1,411	$	1,464
Petroleum products sales to Davison family businesses	$	390	$	654

Transportation Services

We provide truck transportation services to Denbury to move its crude oil from the wellhead to our Mississippi pipeline. Denbury pays us a fee for that trucking service which varies with the distance we haul its crude oil. Those fees are reflected in the Unaudited Consolidated Statements of Operations as supply and logistics revenues.

Denbury is the only shipper (other than us) on our Mississippi pipeline, and we earn tariffs for transporting its oil. We earned fees from Denbury for the transportation of its CO2 on our Free State pipeline. We also earned fees from Denbury under the direct financing lease arrangements for the Olive and Brookhaven crude oil pipelines and the Brookhaven and NEJD CO2 pipelines and recorded pipeline transportation income from those arrangements.

We also provide pipeline monitoring services to Denbury. That revenue is included in pipeline revenues in our Unaudited Consolidated 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. The annual rate and rate for attendance at meetings are the same as the rates at which our other directors were paid.

CO2 Operations and Transportation

Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver CO2 for us to our customers. In the first six months of 2009, the inflation-adjusted transportation fee averaged $0.1976 per Mcf.

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Operations, General and Administrative Services

We do not directly employ any persons to manage or operate our business. Those functions and personnel are provided by our general partner. We reimburse our general partner for all direct and indirect costs of those services, excluding any payments to our management team pursuant to their Class B Membership Interests. See Note 12.

Amounts due to and from Related Parties

At both June 30, 2009 and December 31, 2008, we owed Denbury $1.0 million for CO2 transportation charges and purchases of crude oil. Denbury owed us $1.6 million and $2.0 million for transportation services at June 30, 2009 and December 31, 2008, respectively. We owed our general partner $2.2 million and $2.1 million for administrative services at June 30, 2009 and December 31, 2008, respectively. At both June 30, 2009 and December 31, 2008, Sandhill owed us $0.7 million for purchases of CO2.

DG Marine Joint Venture

Our partner in the DG Marine joint venture is TD Marine, a joint venture consisting of three members of the Davison family. We acquired our refinery services segment as well as certain other businesses from the Davison family in 2007. In connection with that transaction, members of the Davison family, collectively, became our largest unitholder group.

Financing

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. 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.

We guarantee 50% of the obligation of Sandhill to a bank. At June 30, 2009, the total amount of Sandhill's obligation to the bank was $3.0 million; therefore, our guarantee was for $1.5 million.

Approximately 14% of the outstanding common shares of Community Trust Bank are held by Davison family members. Community Trust Bank is a 17% participant in the DG Marine credit facility. James E. Davison, Jr., a member of our board of directors, also serves on the board of the holding company that owns Community Trust Bank.

As discussed in Note 12, we recorded a non-cash capital contribution from our general partner of $4.5 million for the six months ended June 30, 2009 related to the Class B Membership Awards for our executive management team.

12. Equity-Based Compensation

We recorded charges and credits related to our equity-based compensation plans and awards for three and six months ended June 30, 2009 and 2008 as follows:

Expense (Credits to Expense) Related to Equity-Based Compensation

Statement of Operations	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Pipeline operating costs	$51	$20	$84	$(296)
Refinery services operating costs	74	34	150	23
Supply and logistics operating costs	219	74	429	(997)
General and administrative expenses	2,821	277	5,331	(228)
Total	$3,165	$405	$5,994	$(1,498)

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Stock Appreciation Rights Plan

The following table reflects rights activity under our plan during the six months ended June 30, 2009:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at January 1, 2009	1,017,985	$18.09		
Granted during 2009	228,215	$13.00		
Exercised during 2009	(3,627)	$11.08		
Forfeited or expired during 2009	(58,591)	$19.13		
Outstanding at June 30, 2009	1,183,982	$16.61	6.0	$603
Exercisable at June 30, 2009	492,101	$15.82	5.5	$480

The weighted-average fair value at June 30, 2009 of rights granted during the first six months of 2009 was $2.41 per right, determined using the following assumptions:

Assumptions Used for Fair Value of Rights Granted in First Half of 2009	
Expected life of rights (in years)	6.00
Risk-free interest rate	3.04%
Expected unit price volatility	44.58%
Expected future distribution yield	8.50%

The total intrinsic value of rights exercised during the first six months of 2009 was less than $0.1 million, which was paid in cash to the participants.

At June 30, 2009, there was $0.9 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. For the awards outstanding at June 30, 2009, the remaining cost will be recognized over a weighted average period of one year.

2007 Long Term Incentive Plan

The following table summarizes information regarding our non-vested Phantom Unit grants as of June 30, 2009:

Non-vested Phantom Unit Grants	Number of Units	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2009	78,388	$ 19.32
Granted	82,501	$ 8.14
Vested	(23,000)	$ 20.12

Forfeited	(3,500)	$	8.88
Non-vested at June 30, 2009	134,389	$	12.59

The weighted-average fair value of Phantom Units granted during 2009 was determined using the following assumptions:

Grant Date Price	$10.19
Expected Distribution Rate	$0.33
	0.73%
Risk Free Rate	- 1.50 %

The aggregate grant date fair value of Phantom Unit awards granted during the six months ended June 30, 2009 was $0.7 million. As of June 30, 2009, there was $1.0 million of unrecognized compensation expense related to these units. This unrecognized compensation cost is expected to be recognized over a weighted-average period of one year.

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Class B Membership Interests

As part of finalizing the compensation arrangements for our Senior Executives on December 31, 2008, our general partner awarded them an equity interest in our general partner as long-term incentive compensation. These Class B Membership Interests compensate the holders thereof by providing rewards based on increased shares of the cash distributions attributable to our incentive distribution rights (or IDRs) (See Note 9) to the extent we increase Cash Available Before Reserves, or CABR (defined below) (from which we pay distributions on our common units) above specified targets. CABR generally means Available Cash before Reserves, less Available Cash before Reserves generated from specific transactions with our general partner and its affiliates (including Denbury Resources Inc.) The Class B Membership Interests do not provide any Senior Executive with a direct interest in any assets (including our IDRs) owned by our general partner.

Our general partner has agreed that it will not seek reimbursement (on behalf of itself or its affiliates) under our partnership agreement for the costs of these Senior Executive compensation arrangements to the extent relating to their ownership of Class B Membership Interests (including current cash distributions made by the general partner out of its IDRs and payment of redemption amounts for those IDRs) and the deferred compensation amounts. Although our general partner will not seek reimbursement for the costs of the Class B Membership Interests and deferred compensation plan arrangements, we will record non-cash compensation expense attributable to such costs. The Class B Membership Interests awarded to our senior executives are accounted for as liability awards under the provisions of SFAS 123(R). As such, the fair value of the compensation cost we record for these awards is recomputed at each measurement date and the expense to be recorded is adjusted based on that fair value.

Management's estimates of the fair value of these awards are based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we will pay to our general partner, and assumptions about appropriate discount rates. Additionally, the determination of fair value is affected by the distribution yield of a group of publicly-traded entities that are general partners in publicly-traded master limited partnerships, a factor over which we have no control. These assumptions were used to estimate the total amount that would be paid under the Class B Membership awards through the final vesting date and do not represent the contractual amounts payable under these awards at June 30, 2009.

At June 30, 2009, we computed the fair value of the awards utilizing a discount rate of 14%, representing the risks inherent in the assumptions we used and the time until final vesting. Due to the limited number of participants in the Class B Membership awards, we assumed a forfeiture rate of zero. At June 30, 2009, management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives is approximately $20.7 million. Management's estimates of fair value were made in order to record non-cash compensation expense over the vesting period, and do not necessarily represent the contractual amounts payable under these awards at June 30, 2009.

The fair value of these incentive awards will be recomputed each quarter through the final settlement of the awards. The fair value to be recorded by us as compensation expense in each quarterly period will be the excess of the recomputed estimated fair value over the previously recorded amounts, and will consider the vesting conditions for the awards. This expense will be recorded on an accelerated basis to align with the requisite service period of the award. Changes in our assumptions will change the amount of compensation cost we record. For the three and six months ended June 30, 2009, we recorded expense of $2.4 million and $4.5 million, respectively.

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13. Supplemental Cash Flow Information

The following table provides information regarding the net changes in components of operating assets and liabilities.

	Six Months Ended June 30, 2009	2008
Decrease (increase) in:		
Accounts receivable	$ (7,606)	$ (57,689)
Inventories	(13,385)	(2,796)
Other current assets	(5,864)	(76)
Increase (decrease) in:		
Accounts payable	3,310	40,190
Accrued liabilities	(5,295)	2,137
Net changes in components of operating assets and liabilities,net of working capital acquired	$ (28,840)	$ (18,234)

Cash received by us for interest for the six months ended June 30, 2009 and 2008 was $37,000 and $94,000, respectively. Payments of interest and commitment fees were $7.8 million and $3.9 million for the six months ended June 30, 2009 and 2008, respectively.

Cash paid for income taxes during the six months ended June 30, 2009 and 2008 were $1.6 million and $0.4 million, respectively.

At June 30, 2009, we had incurred liabilities for fixed asset and other asset additions totaling $1.2 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 and intangible assets” and “Other, net” under investing activities on the Unaudited Consolidated Statements of Cash Flows. At June 30, 2008, we had incurred $1.5 million of liabilities that had not been paid at that date and are not included in “Payments to acquire fixed and intangible 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 for the six months ended June 30, 2008.

14. Major Customers and Credit Risk

Due to the nature of our supply and logistics operations, a disproportionate percentage of our trade receivables consist of obligations of energy 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 12% and 17% of total revenues in the six months ended June 30, 2009 and 2008, respectively. The majority of the revenues from this customer in both periods relate to our crude oil supply and logistics operations.

15. Derivatives

On January 1, 2009, we adopted SFAS 161 which requires enhanced disclosures about (1) how and why we use derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), and (3) how derivative instruments and related hedged items affect our financial position, financial performance and cash flows.

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Commodity Derivatives

We have exposure to commodity price changes related to our inventory and purchase commitments. We utilize derivative instruments (primarily futures and options contracts traded on the NYMEX) to hedge our exposure to commodity prices, primarily crude oil, fuel oil and petroleum products; however only a portion of these instruments are designated as hedges under the provisions of SFAS 133. Our decision as to whether to designate derivative instruments as fair value hedges under SFAS 133 relates to our expectations of the length of time we expect to have the commodity price exposure and our expectations as to whether the derivative contract will qualify as highly effective under SFAS 133 in limiting our exposure to commodity price risk. Most of the petroleum products, including fuel oil, that we supply cannot be hedged with a high degree of effectiveness with derivative contracts available on the NYMEX, therefore we do not designate derivative contracts utilized to limit our price risk related to these products as hedges for accounting purposes. Typically we utilize crude oil and natural gas futures and option contracts to limit our exposure to the effect of fluctuations in petroleum products prices on the future sale of our inventory or commitments to purchase petroleum products, and we recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales. The recognition of changes in fair value of the derivative contracts not designated as hedges under SFAS 133 can occur in reporting periods that do not coincide with the recognition of gain or loss on the actual transaction being hedged, therefore we will, on occasion, report gains or losses in one period that will be partially offset by gains or losses in a future period when the hedged transaction is completed.

We have designated certain crude oil futures contracts as hedges of crude oil inventory due to our expectation that these contracts will be highly effective in hedging our exposure to fluctuations in crude oil prices during the period that we expect to hold that inventory. We account for these derivative instruments as fair value hedges under the provisions of SFAS 133. Changes in the fair value of these derivative instruments designated as fair value hedges are used to offset related changes in the fair value of the hedged crude oil inventory. Any hedge ineffectiveness in these fair value hedges and any amounts excluded from effectiveness testing are recorded as a gain or loss in the consolidated statements of operations.

In accordance with NYMEX requirements, we fund the margin associated with our loss positions on commodity derivative contracts traded on the NYMEX. The amount of the margin is adjusted daily based on the fair value of the commodity contracts. The margin requirements are intended to mitigate a party’s exposure to market volatility and the associated contracting party risk. We offset fair value amounts recorded for our hedge contracts against margin funded to the NYMEX in Other Current Assets in our Unaudited Consolidated Balance Sheets.

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At June 30, 2009, we had the following outstanding derivative commodity futures, forwards and options contracts that were entered into to hedge inventory or fixed price purchase commitments:

	Sell (Short) Contracts	Buy (Long) Contracts
Designated under SFAS 133:		
Crude oil futures:		
Contract volumes (1,000 bbls)	322	138
Weighted average contract price per bbl	$ 64.34	$ 70.19
Not qualifying or not designated under SFAS 133:		
Crude oil futures:		
Contract volumes (1,000 bbls)	239	47
Weighted average contract price per bbl	$ 68.79	$ 67.98
Heating oil futures:		
Contract volumes (1,000 bbls)	89	12
Weighted average contract price per gal	$ 1.93	$ 1.77
RBOB gasoline futures:		
Contract volumes (1,000 bbls)	$ 10	1
Weighted average contract price per gal	$ 1.89	$ 1.89
Crude oil written options:		
Contract volumes (1,000 bbls)	35	-
Weighted average premium received	$ 2.93	$ -

Interest Rate Derivatives

DG Marine utilizes swap contracts with financial institutions to hedge interest rates for $32.9 million of its outstanding debt through July 2011. The weighted average interest rate of these swap contracts is 4.15%. Because DG Marine expects these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates, we have designated these swap contracts as cash flow hedges under the provisions of SFAS 133. The effective portion of the derivative represents the change in fair value of the hedge that offsets the change in fair value of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts is reported as a component of Accumulated Other Comprehensive Income (Loss) (AOCI) and reclassified into future earnings contemporaneously as interest expense associated with the underlying debt under the DG Marine credit facility is recorded. To the extent that the change in the fair value of the interest rate swaps does not perfectly offset the change in the fair value of our exposure to interest rates, the ineffective portion of the hedge will be immediately recognized in interest expense in our Unaudited Consolidated Statements of Operations.

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Financial Statement Impacts

The following table summarizes the accounting treatment and classification of our derivative instruments on our Unaudited Consolidated Financial Statements.

		Impact of Unrealized Gains and Losses	
Derivative Instrument	Hedged Risk	Unaudited Consolidated Balance Sheets	Unaudited Consolidated Statements of Operations
Designated under SFAS 133:			
Crude oil futures contracts(fair value hedge)	Volatility in crude oil prices - effect on market value of inventory	Derivative is recorded in Other Current Assets (offset against margin deposits) and offsetting change in fair value of inventory is recorded in Inventory	Excess, if any, over effective portion of hedge is recorded in Supply and Logistics - Cost of Sales. Effective portion is offset in Cost of Sales against change in value of inventory being hedged
Interest rate swaps(cash flow hedge)	Changes in interest rates	Entire hedge is recorded in Accrued Liabilities or Other Liabilities depending on duration	Expect hedge to fully offset hedged risk; no ineffectiveness recorded Effective portion is. recorded in interest expense.
Not qualifying or not designated under SFAS 133:			
Commodity hedges consisting of crude oil, heating oil and natural gas futures and forward contracts and call options	Volatility in crude oil and petroleum products prices - effect on market value of inventory or purchase commitments.	Derivative is recorded in Other Current Assets (offset against margin deposits) or Accrued Liabilities	Entire amount of change in fair value of hedge is recorded in Supply and Logistics - Cost of Sales

Unrealized gains are subtracted from net income and unrealized losses are added to net income in determining cash flows from operating activities. Additionally, the offsetting change in the fair value of inventory that is recorded for our fair value hedges is also eliminated from net income in determining cash flows from operating activities. Changes in margin deposits necessary to fund unrealized losses also affect cash flows from operating activities.

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The following tables reflected the estimated fair value gain (loss) position of our hedge derivatives and related inventory impact for qualifying hedges at June 30, 2009:

	Fair Value of Derivative Assets and Liabilities			
	Derivative Assets	Unaudited Consolidated Balance Sheets Location	Derivative Liabilities	Unaudited Consolidated Balance Sheets Location
Commodity derivatives - futures and call options:				
Hedges designated under SFAS 133 as fair value hedges	$ 72	Other Current Assets	$ (2,124)(1)	Other Current Assets
Undesignated hedges	332	Other Current Assets	(670)(1)	Other Current Assets
Total commodity derivatives	404		(2,794)	
Interest rate swaps designated as cash flow hedges:				
Portion expected to be reclassified into earnings within one year			(947)	Accrued Liabilities
Portion expected to be reclassified into earnings after one year			(812)	Other Liabilities
Total derivatives	$ 404		$ (4,553)	

(1) These derivative liabilities have been funded with margin deposits recorded in our Unaudited Consolidated Balance Sheet in Other Current Assets.

	Effect on Unaudited Consolidated Statements of Operations and Other Comprehensive Income (Loss) Amount of Gain (Loss) Recognized in Income		
	Supply & Logistics - Product Costs	Interest Expense Reclassified from AOCI	Other Comprehensive Income (Loss) Effective Portion

Commodity derivatives - futures and call options:			
Hedges designated under SFAS 133	$ (4,852)(1)	$ -	$ -
Undesignated hedges	(2,363)		
Total commodity derivatives	(7,215)	-	-
Interest rate swaps designated as cash flow hedges		(290)	(85)
Total derivatives	$ (7,215)	$ (290)	$ (85)

(1) Represents the amount of loss recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain on the hedged inventory under the fair value hedge of $6.2 million.

During the first half of 2009, DG Marine's interest rate hedges fully offset the hedged risk; therefore, there was no ineffectiveness recorded for the hedges.

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We expect to reclassify $0.9 million in unrealized losses from AOCI into interest expense during the next 12 months. Because a portion of these losses are based on market prices at the current period end, actual amounts to be reclassified to earnings will differ and could vary materially as a result of changes in market conditions. We have no derivative contracts with credit contingent features.

16. Fair-Value Measurements

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value at June 30, 2009		
Recurring Fair Value Measures	Level 1	Level 2	Level 3
Commodity derivatives:			
Assets	$404	$-	$-
Liabilities	$(2,794)	$-	$-
Interest rate swaps - Liabilities	$-	$-	$(1,759)

Level 1

Included in Level 1 of the fair value hierarchy are commodity 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 of the fair value hierarchy.

Level 2

At June 30, 2009, we had no Level 2 fair value measurements.

Level 3

Included within Level 3 of the fair value hierarchy are our interest rate swaps. The fair value of our interest rate swaps is based on indicative broker price quotations. These derivatives are included in Level 3 of the fair value hierarchy because broker price quotations used to measure fair value are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these Level 3 derivatives is not based upon significant management assumptions or subjective inputs.

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives measured at fair value using inputs classified as Level 3 in the fair value hierarchy:

	Three Months	Six Months Ended

	Ended June 30, 2009	June 30, 2009
Balance at beginning of period	(1,960)	$(1,964)
Realized and unrealized gains (losses)-		
Reclassified into interest expense for settled contracts	158	290
Included in other comprehensive income	43	(85)
Balance at end of period	$(1,759)	$(1,759)
Total amount of losses for the six months ended June 30, 2009, included in earnings attributable to the change in unrealized losses relating to liabilities still held at June 30, 2009		$(13)

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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, (2) valuing asset retirement obligations pursuant, and (3) valuing potential impairment loss related to long-lived assets accounted for pursuant to SFAS 144.

17. Contingencies

Guarantees

We guaranteed to the lessor approximately $1.2 million of residual value related to the leases of trailers. We also guaranteed 50% of the obligations of Sandhill under a credit facility with a bank. At June 30, 2009, Sandhill owed $3.0 million; therefore our guaranty was $1.5 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year. We believe the likelihood that we would be required to perform or otherwise incur any significant losses associated with either of these guarantees is remote.

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

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. Such 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 are subject to lawsuits in the normal course of business, as well as examinations 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.

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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
- Available Cash before Reserves
- Results of Operations
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- New Accounting Pronouncements

In the discussions that follow, we will focus on two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before Reserves. During the fourth quarter of 2008, we revised the manner in which we internally evaluate our segment performance. As a result, we changed our definition of segment margin to include within segment margin all costs that are directly associated with a business segment. Segment margin now includes costs such as general and administrative expenses that are directly incurred by a business segment. Segment margin also includes all payments received under direct financing leases. In order to improve comparability between periods, we exclude from segment margin the non-cash effects of our stock-based compensation plans which are impacted by changes in the market price for our common units. Previous periods have been retrospectively revised to conform to this segment presentation. We now define segment margin as revenues less cost of sales, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. In addition, our segment margin definition excludes the non-cash effects of our stock-based compensation plans, and includes the non-income portion of payments received under direct financing leases. 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. A reconciliation of segment margin to income from before income taxes is included in our segment disclosures in Note 10 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 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 such joint ventures, the elimination of gains and losses on asset sales (except those from the sale of surplus assets) 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 Reconciliation" below.

Overview

In the second quarter of 2009, we reported net income of $4.5 million, or $0.13 per common unit. Non-cash expense related to our senior executive compensation arrangements totaling $2.4 million reduced net income during the second quarter. See additional discussion of our senior executive compensation expense in "Results of Operations – Other Costs, Interest and Income Taxes" below.

During the second quarter of 2009, we generated $22.2 million of Available Cash before Reserves, and we will distribute $15.3 million to holders of our common units and general partner for the second quarter. During the second quarter of 2009, cash provided by operating activities was $15.9 million.

Macroeconomic conditions have adversely affected business conditions in several of the industries that we service, and, consequently, us. Segment margin as compared to the second quarter of 2008, after consideration of the effects of acquisitions in 2008, declined for all of our segments. However, when compared to the first quarter of 2009, we have seen an increase in total segment margin of $1.0 million.

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On July 15, 2009, we announced that our distribution to our common unitholders relative to the second quarter of 2009 will be $0.345 per unit (to be paid in August 2009). This distribution amount represents a 9.5% increase from our distribution of $0.315 per unit for the second quarter of 2008. During the second quarter of 2009, we paid a distribution of $0.3375 per unit related to the first quarter of 2009.

The current economic crisis has restricted the availability of credit and access to capital in our business environment. Despite efforts by U.S. Treasury and banking regulators to provide liquidity to the financial sector, certain components of the capital markets continue to remain constrained. While we anticipate that the challenging economic environment will continue for the foreseeable future, we believe that our current cash balances, future internally-generated funds and funds available under our credit facility will provide sufficient resources to meet our current working capital needs. The financial performance of our existing businesses and the fact that we do not need to access the capital markets (other than opportunistically), may allow us to take advantage of acquisition and/or growth opportunities that may develop.

Our ability to fund large new projects or make large acquisitions in the near term may be limited by the current conditions in the credit and equity markets which may impact our ability to issue new debt or equity financing. We may consider other arrangements to fund large growth projects and acquisitions such as private equity and joint venture arrangements.

Available Cash before Reserves

Available Cash before Reserves was as follows (in thousands):

	Three Months Ended		Six Months Ended	
	June 30, 2009	June 30, 2008	June 30, 2009	June 30, 2008
Net income attributable to Genesis Energy, L.P.	$4,456	$7,328	$9,746	$8,973
Depreciation and amortization	16,133	16,721	31,552	33,510
Cash received from direct financing leases not included in income	929	397	1,836	544
Cash effects of sales of certain assets	52	181	457	426
Effects of available cash generated by equity method investees not included in income	170	643	(1,119)	1,066
Cash effects of stock appreciation rights plan	(3)	(113)	(7)	(271)
Non-cash tax expense	627	700	1,087	(926)
Earnings of DG Marine in excess of distributable cash	(904)	-	(2,874)	-
Non-cash equity-based compensation expense	3,165	406	5,994	(348)
Other non-cash items, net	(943)	130	(700)	(18)
Maintenance capital expenditures	(1,474)	(208)	(2,422)	(984)
Available Cash before Reserves	$22,208	$26,185	$43,550	$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, 2009 and 2008 in "Liquidity and Capital Resources – Non-GAAP Reconciliation" below. For the three and six months ended June 30, 2009, cash flows provided by operating activities were $15.9 million and $19.1 million, respectively. 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.

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Results of Operations

The contribution of each of our segments to total segment margin in the three and six month periods ended June 30, 2009 and 2008 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Pipeline transportation	$10,347	$7,261	$20,572	$11,922
Refinery services	13,190	16,279	25,949	28,709
Supply and logistics	6,600	7,780	12,556	11,841
Industrial gases	2,869	3,686	5,892	6,885
Total segment margin	$33,006	$35,006	$64,969	$59,357

Pipeline Transportation Segment

Operating results for our pipeline transportation segment were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
Pipeline System	2009	2008	2009	2008
Mississippi-Bbls/day	24,159	24,873	24,758	23,864
Jay - Bbls/day	9,307	11,828	9,369	13,222
Texas - Bbls/day	25,069	30,733	27,435	29,647
Free State - Mcf/day	134,570	152,191 (1)	152,830	152,191 (1)

(1) Represents the volume per day for one month we owned the pipeline in 2008 period.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$3,997	$3,979	$7,950	$8,105
Non-income payments under direct financing leases	929	397	1,836	544
Sales of crude oil pipeline loss allowance volumes	1,406	2,868	2,205	5,326
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	6,376	2,245	13,120	2,323
Tank rental reimbursements and other miscellaneous revenues	140	166	318	434
Revenues from natural gas tariffs and sales	537	1,628	1,270	2,983
Natural gas purchases	(470)	(1,568)	(1,124)	(2,854)
Pipeline operating costs, excluding non-cash charges for our equity-based compensation plans and other non-cash charges	(2,568)	(2,454)	(5,003)	(4,939)

Segment margin	$10,347	$7,261	$20,572	$11,922

Three Months Ended June 30, 2009 Compared with Three Months Ended June 30, 2008

Pipeline segment margin for the second quarter of 2009 increased $3.1 million as compared to the second quarter of 2008. The significant component of this change is an increase in revenues from CO2 financing leases and tariffs of $4.1 million and a related increase in non-income payments from the same financing leases of $0.5 million. Reducing the impact of this increase was a decrease in revenues from sales of pipeline loss allowance volumes of $1.5 million.

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Although volumes on our crude oil pipelines declined between the two periods, differences in tariff rates offset the impact of the volumetric changes. The decreased volumes were principally due to a producer connected to our Jay System shutting in production in 2009. The impact of volume decreases on the Texas System on revenues is not very significant due to the relatively low tariffs on that system. Approximately 76% of the volume on that system in the second quarter was shipped on a tariff of $0.31 per barrel.

The decline in market prices for crude oil reduced the value of our pipeline loss allowance volumes and, accordingly, our loss allowance revenues. Average crude oil market prices decreased approximately $62 per barrel between the two quarters. Pipeline loss allowance volumes combined with net volumetric measurement gains were approximately 22,000 barrels in the each period

Revenues and payments related to CO2 pipelines increased by a total of $4.6 million between the two quarters, with $3.5 million attributable to the NEJD pipeline and $1.1 million to the Free State pipeline. The second quarter of 2008 included only one month of results related to these pipelines. The average volume transported on the Free State pipeline for the second quarter of 2009 was 135 MMcf per day, with the transportation fees and the minimum payments totaling $1.6 million and $0.3 million, respectively. Denbury has exclusive use of this pipeline and variations in its CO2 tertiary oil recovery activities create the fluctuations in the volumes transported on the Free State pipeline.

Six Months Ended June 30, 2009 Compared with Six Months Ended June 30, 2008

Pipeline segment margin between the six month periods increased $8.7 million. The significant component of this change is an increase in revenues from CO2 financing leases and tariffs of $10.8 million and a related increase in non-income payments from the same financing leases of $1.3 million. The six-month period in 2008 only included results from the NEJD and Free State CO2 pipelines for a one-month period while the 2009 period included six months of results.

Partially offsetting these increases was a decrease in revenues from sales of pipeline loss allowance volumes of $3.1 million related almost exclusively to the significant decline (an average of $58 per barrel) in crude oil prices between the two periods.

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Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
NaHS volumes (Dry short tons "DST")	20,908	46,655	47,137	88,397
NaOH volumes (DST)	19,763	16,758	36,663	32,663
Total	40,671	63,413	83,800	121,060
NaHS revenues	$20,903	$44,384	$52,202	$78,100
NaOH revenues	11,552	9,481	27,136	17,574
Other revenues	2,139	1,862	3,550	3,965
Total revenues	$34,594	$55,727	$82,888	$99,639
Segment margin	$13,190	$16,279	$25,949	$28,709
Average index price for NaOH per DST (1)	$450	$547	$640	$502
Raw material and processing costs as % of segment revenues	47 %	55 %	54 %	53 %
Delivery costs as a % of segment revenues	11 %	16 %	11 %	17 %

(1) Source: Harriman Chemsult Ltd.

Three Months Ended June 30, 2009 Compared with Three Months Ended June 30, 2008

Refinery services segment margin for the second quarter of 2009 was $13.2 million, a decrease of $3.1 million, or 19%, from the comparative period in 2008. The significant components of this fluctuation were as follows:

- A decline in NaHS volumes of 55%. Macroeconomic conditions have negatively impacted the demand for NaHS, primarily in mining and industrial activities. As market prices and demand for copper and molybdenum improve, we would expect demand for NaHS to increase. Similarly, improvements in industrial activities including the paper and pulp and tanning industries are expected to improve NaHS demand.
- An increase in NaOH sales volumes of 18%. NaOH (or caustic soda) is a key component in the provision of our services for which we receive the by-product NaHS. We are a very large consumer of caustic soda, and our economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties.
- Volatile caustic prices. Market prices for caustic soda increased throughout 2008 to a high of approximately $1,000 per DST in the fourth quarter of 2008. Since that time market prices of caustic soda have decreased to approximately $325 per DST. This volatility affects both the cost of caustic soda used to provide our services as well as the price at which we sell NaHS.
- Aggressive management of production costs. Raw material and processing costs related to providing our refinery services and supplying caustic soda as a percentage of our segment revenues declined 8% between the periods. The key component in the provision of our refinery services is caustic soda. In addition, as discussed above, we also market caustic soda. As the market price of caustic soda has fluctuated in 2008 and 2009, we have managed our acquisition costs by managing the timing of our purchases and our logistics costs. We have also taken steps to

reduce processing costs.

- Lower logistics costs. The costs of delivering NaHS and caustic soda to our customers declined as a percentage of segment revenues by 5% between the two quarterly periods. Freight demand and fuel prices declined in the 2009 period as economic conditions reduced transportation needs in the market and the decline in crude oil prices reduced the cost of fuel used in transporting these products. We also adjusted the modes of transportation being used to transport NaHS and caustic soda between rail, barge and truck to improve logistics costs.

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Six Months Ended June 30, 2009 Compared with Six Months Ended June 30, 2008

Segment margin for our refinery services decreased $2.8 million between the six months ended June 30, 2009 and the same period in 2008. The reasons for this decline were similar to the quarterly comparison as follows:

- NaHS volumes declined 47%, as a result of macroeconomic conditions.
- Caustic soda sales volumes increased 12% partly offsetting the impact of the decline in NaHS activity.
- Revenues only decreased 17% as market prices for caustic soda in the six months ended June 30, 2009 ranged from approximately $1,000 per DST to $325 per DST as compared to a range of approximately $400 to $600 per DST in 2008. As the majority of our NaHS sales prices fluctuate with the market price of caustic soda, revenues did not decline as significantly as volumes.
- Raw material and processing costs as a percentage of segment revenues remained relatively constant between periods.
- Delivery costs declined due to freight demand in the market and fuel prices.

Supply and Logistics Segment

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Supply and logistics revenue	$291,364	$569,477	$480,426	$999,595
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(266,631)	(542,200)	(431,948)	(949,475)
Operating and segment general and administrative costs, excluding non-cash charges for stock-based compensation and other non-cash expenses	(18,133)	(19,497)	(35,922)	(38,279)
Segment margin	$6,600	$7,780	$12,556	$11,841
Volumes of crude oil and petroleum products -average barrels per day	47,941	47,757	45,257	47,611

Three Months Ended June 30, 2009 as Compared to Three Months Ended June 30, 2008

Although our segment margin declined by $1.2 million, or 15.2%, comparatively between the second quarters of 2009 and 2008, the market prices of crude oil and petroleum declined by more than $60 per barrel, or approximately 50%. That price volatility had a limited impact on our segment margin.

The key factors affecting the two quarters were as follows:

– Acquisition of inland marine transportation operations of Grifco in third quarter of 2008 (increased segment margin by $2.5 million);

– Crude oil contango market conditions (increased segment margin by $0.9 million); and

–

Reduction in opportunities for us to take advantage of purchasing and blending of crude oil and products (reduced segment margin by $4.6 million).

The inland marine transportation operations of Grifco Transportation, acquired by DG Marine in the third quarter of 2008, added $2.5 million to segment margin in the second quarter of 2009. These operations provided us with an additional capability to provide transportation services of petroleum products by barge.

During the second quarter of 2009, crude oil markets were in contango (oil prices for future deliveries are higher than for current deliveries), providing an opportunity for us to purchase and store crude oil as inventory for delivery in future months. The crude oil markets were not in contango in the second quarter of 2008. During the second quarter of 2009, we held an average of approximately 226,000 barrels of crude oil in our storage tanks and hedged this volume with futures contracts on the NYMEX. We are accounting for the effects of this inventory position and related derivative contracts as a fair value hedge under financial accounting rules. The effect on segment margin for the amount excluded from effectiveness testing related to this fair value hedge was a $0.9 million gain in the second quarter of 2009.

Offsetting these improvements in segment margin was a decrease in the margins from our crude oil gathering and petroleum products marketing operations. In 2009, we experienced some reductions in volumes as a result of crude oil producers' choices to reduce operating expenses or postpone development expenditures that could have maintained or enhanced their existing production levels. As a consequence of the reductions in volumes, our segment margin from crude oil gathering declined between the quarterly periods by $1.5 million. Also, market inefficiencies developed in heavy-end refined products in the 2008 quarter as crude oil and light-end refined products experienced sharp price increases. Due to our logistics equipment, we were able to benefit from improved blending economics in 2008. In the second quarter of 2009, demand for gasoline declined significantly and refiners reduced their production rates. Our blending economics narrowed as volatility in prices declined in correlation to decreased demand. Somewhat offsetting these declines were the additional opportunities to handle volumes from the heavy end of the refined barrel due to our access to additional leased heavy products storage capacity and to barge transportation capabilities through DG Marine. However, as a result of these factors, our segment margin decreased by $3.1 million related to petroleum products and related activities.

Six Months Ended June 30, 2009 as Compared to Six Months Ended June 30, 2008

Segment margin for the six month period in 2009 was affected by the same factors as in the second quarter, although the result was slight increase in segment margin of $0.7 million. For the six-month periods, the key factors described above had an impact as follows:

– Acquisition of inland marine transportation operations of Grifco in third quarter of 2008 (increased segment margin by $5.6 million);

– Reduction in opportunities for us to take advantage of purchasing and blending of crude oil and petroleum products (reduced segment margin by $6.3 million); and

– Crude oil contango market conditions (increased segment margin by $1.4 million).

Industrial Gases Segment

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

CO_2 - Industrial Customers - We supply CO_2 to industrial customers under seven long-term CO_2 sales contracts. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer

Price Index, with a minimum price.

Our industrial customers treat the CO_2 and transport it to their customers. The primary industrial applications of CO_2 by those customers include beverage carbonation and food chilling and freezing. Based on historical data for 2004 through the first quarter of 2009, we can expect some seasonality in our sales of CO_2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. Our industrial customers also provide CO_2 to companies engaged in tertiary oil recovery activities.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Revenues from CO2 marketing	$3,791	$4,450	$7,520	$8,320
CO2 transportation and other costs	(1,356)	(1,391)	(2,679)	(2,663)
Available cash generated by equity investees	434	627	1,051	1,228
Segment margin	$2,869	$3,686	$5,892	$6,885
Volumes per day:				
CO2 marketing - Mcf	70,621	79,968	70,229	76,515

Three Months Ended June 30, 2009 Compared with Three Months Ended June 30, 2008

The decrease in margin from the industrial gases segment between the two quarterly periods was the result of a decrease in volumes sold and a slight decrease in the average sales price of CO2 to our customers. During the second quarter of 2009, volumes declined 12% as compared to the 2008 second quarter as customers reduced purchases. Variations in the volumes sold among contracts with different pricing terms resulted in the average sales price of the CO2 decreasing $0.02 per Mcf, or 4%.

In addition, our industrial gases segment experienced increased costs in 2009, primarily costs to transport CO2 to our customers. The inflation adjustments to the rates we pay Denbury to transport the CO2 to our customers increased the average transportation rates by 4.1% over the average rates in the 2008 second quarter.

Our share of the available cash before reserves generated by our equity investments in each quarterly period primarily resulted from our investment in T&P Syngas.

Six Months Ended June 30, 2009 Compared with Six Months Ended June 30, 2008

The decrease in margin from the industrial gases segment between the two six-month periods was the result of a decrease in volumes sold and a decrease in the average sales price of CO2 to our customers. During the first half of 2009, volumes declined 8% as compared to the 2008 first half as customers reduced volumes while performing maintenance activities at their facilities. Variations in the volumes sold among contracts with different pricing terms resulted in the average sales price of the CO2 decreasing $0.01 per Mcf, or 1%.

The inflation adjustment to the rate we pay Denbury to transport the CO2 to our customers resulted in greater CO2 transportation costs in the first quarter of 2009 when compared to the 2008 quarter. The transportation rate increase between the two periods was 4.1%.

Our share of the available cash before reserves generated by our equity investments in each period primarily resulted from our investment in T&P Syngas.

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,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
General and administrative expenses not separately identified below	$4,706	$7,605	$10,095	$15,471
Bonus plan expense	779	1,284	1,634	2,447
Equity-based compensation plans expense (credit)	468	277	832	(228)
Compensation expense related to management team	2,353	-	4,499	-
Total general and administrative expenses	$8,306	$9,166	$17,060	$17,690

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Comparing the three-month periods and the six-month periods, the primary factor driving the increase in general administrative expenses related to the charge recorded for the compensation arrangement between our senior executive team and our general partner. On December 31, 2008, our general partner and our senior executive management team entered into a compensation arrangement whereby our executive team may earn an interest in our incentive distribution rights owned by our general partner. While our general partner will bear the cash cost this compensation with our senior executives, we record the expense of the arrangements with an offsetting non-cash capital contribution by our general partner. As discussed in Note 12 under Class B Membership Interests, we estimate the fair value of the awards to our senior executives at each reporting date and adjust the expense we have recorded based on that fair value. Based on the fair value estimate at June 30, 2009 of $20.7 million, we recorded expense for the second quarter of 2009 of $2.4 million, and a total of $4.5 million for the six months in 2009. The fair value of the awards is being recorded on an accelerated basis due to the vesting conditions contained in the awards, so as to match the expense recorded to the service period required for vesting.

Fluctuations in our common unit price from the beginning to the end of each period and the issuance of additional stock appreciation rights and phantom units resulted in variations in the equity-based compensation expense between periods. These charges will continue to fluctuate with changes in the market price of our common units until such time as the stock appreciation rights are exercised, forfeited or expire.

Reductions in travel costs, audit and tax professional services and bonus expense offset a portion of the increased amounts in the three and six month periods.   The remaining decrease in expense was related to further integration of the operations we acquired in 2007.

Depreciation and amortization expense. Depreciation and amortization expense decreased by $2.0 million between the six-month periods ended June 30 primarily as a result of the amortization expense recognized on intangible assets. For the second quarter periods, the decrease in depreciation and amortization expense was $0.6 million, with a decline in intangible amortization offset by depreciation on the DG Marine assets acquired in July 2008.

We are amortizing our intangible assets over the period during which the intangible asset is expected to contribute to our future cash flows.   The amortization we record on these assets is greater in the initial years after the acquisition because intangible assets such as customer relationships and trade names are generally more valuable in the first years after an acquisition. As such, the amount of amortization we have recorded has declined since the intangible assets were acquired in 2007.

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Interest expense, including commitment fees,excluding DG Marine	$1,966	$2,039	$3,781	$3,713
Amortization of facility fees, excluding DG Marine facility	165	165	328	330
Interest expense and commitment fees -DG Marine	1,281	-	2,445	-
Capitalized interest	(23)	(48)	(109)	(101)
Interest income	(16)	(117)	(37)	(234)
Net interest expense	$3,373	$2,039	$6,408	$3,708

On May 30, 2008, we increased our debt to fund the drop-down transactions from Denbury. As a result, our average outstanding debt balance under our credit facility in the second quarter of 2009 increased by $183.5 million over the average outstanding debt balance in the second quarter of 2008. Our average interest rate, however, was 2.2% lower during the 2009 quarter, resulting in a decrease for the quarter of $0.1 million. DG Marine incurred interest expense in the second quarter of $1.3 million under its credit facility.

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For the six-month periods, our average outstanding debt balance was $226.6 million greater in 2009 than 2008. Our average interest rate was 2.8% less in the 2009 period than the 2008 period. For the six month period, DG Marine's interest expense was $2.4 million under its credit facility.

Income tax expense. Income tax expense is based on non-qualified income generated in the period and Texas Margin Tax on our operations in Texas. In the second quarter of 2009, non-qualified income increased in relation to the tax deductions attributable to that income, resulting in an increase in income tax expense. As the majority of our operations are not taxable to us, income tax expense is not expected to be significant.

Liquidity and Capital Resources

Capital Resources/Sources of Cash

Although credit and access to capital continue to be negatively impacted by current economic conditions in our business environment, recent market trends have indicate improvements in bank lending capacity and long-term interest rates. We anticipate that our short-term working capital needs will be met through our current cash balances, future internally-generated funds and funds available under our credit facility. Existing capacity in our credit facility and $6.9 million of cash on hand, as well as the absence of any need to access the capital markets, may allow us to take advantage of attractive acquisition and/or growth opportunities that develop.

For the long-term, we continue to pursue a growth strategy that requires significant capital. We expect our long-term capital resources to include equity and debt offerings (public and private) and other financing transactions, in addition to cash generated from our operations. Accordingly, we expect to access the capital markets (equity and debt) from time to time to partially refinance our capital structure and to fund other needs including acquisitions and ongoing working capital needs. Our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital, to utilize our current credit facility and to implement our growth strategy successfully. No assurance can be made that we will be able to raise the necessary funds on satisfactory terms. 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.

We continue to monitor the credit crisis and the economic outlook to determine the extent of the impact on our business environment. While some increase in commodity prices for copper has occurred during the first half of 2009, continuing weak demand in the United States for fuel has impacted refiners to whom we sell crude oil and has reduced the availability of petroleum products for our marketing activities due to reduced refining operating levels. Difficulties for companies in the mining, paper and pulp products and leather industries have reduced demand by producers of these goods for the NaHS used in their processes. We continue to adjust to the effects of these macro-economic factors in our operating levels and financial decisions.

Our consolidated balance sheet at June 30, 2009 includes total long-term debt of $399.4 million, consisting of $53.1 million outstanding under the non-recourse DG Marine credit facility and $346.3 million outstanding under our credit facility. Outstanding letters of credit under our credit facility at June 30, 2009 were $4.4 million. Our borrowing base under our $500 million credit facility is a function of our EBITDA (earnings before interest, taxes, depreciation and amortization), as defined in our credit agreement for our most recent four calendar quarters.

Our credit facility has provisions that allow us to increase our borrowing base for material acquisitions. Upon the completion of four full quarters of operations including the acquired operations, the EBITDA multiple used to determine our borrowing base is reduced from 4.75 times to 4.25 times. In mid-August, upon reporting to our lenders our fourth full quarter of operations including the pipeline dropdown transactions from Denbury that occurred in May 2008, our borrowing base will be calculated using our last four quarters of EBITDA with a 4.25 multiplier, which will result in a decrease in our borrowing base to $419 million. This decrease in the borrowing base will result in approximately $68 million of remaining credit in addition to cash on hand and cash we have temporarily invested in crude oil and petroleum products inventories. We believe that this level of credit will provide us sufficient liquidity to operate our business. We have committed capital available under our credit facility up to $500 million that we can access for material acquisitions that meet criteria specified in our credit agreement with the calculation of our borrowing base using the higher multiple and an agreed-upon amount of pro forma EBITDA associated with the acquisition.

DG Marine had $53.1 million of loans outstanding under its $90 million credit facility. As of June 30, 2009, DG Marine had completed and paid for all amounts related to the capital expenditure projects reflected in its calendar 2009 budget, and we do not anticipate utilizing the remaining availability under DG Marine's credit facility except to fund any future capital projects of DG Marine.

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Uses of Cash

Our cash requirements include funding day-to-day operations, maintenance and expansion capital projects, debt service, 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.

Cash Flows from Operations. We utilize the cash flows we generate from our operations to fund our working capital needs. Excess funds that are generated are used to repay borrowings from our credit facilities and to fund capital expenditures. Our operating cash flows can be impacted by changes in items of working capital, primarily variances in the timing of payment of accounts payable and accrued liabilities related to capital expenditures.

Debt and Other Financing Activities. Our sources of cash are primarily from operations and our credit facilities. Our net borrowings under our credit facility and the DG Marine credit facility totaled $24.1 million during the first half of 2009. These borrowings related primarily to the investment in fixed assets and the payment of liabilities accrued at year end for such items as annual bonus payments and property tax obligations. Additionally, funds were utilized to increase our crude oil inventory levels due to the contango market conditions. We paid distributions totaling $28.8 million to our limited partners and our general partner during the first half of 2009. See the details of distributions paid in "Distributions" below.

Investing. We utilized cash flows for capital expenditures. The most significant investing activities in the first half of 2009 were expenditures by DG Marine of $15.7 million for additional barges and related costs. As of June 30, 2009, DG Marine had twenty barges and ten push boats. DG Marine's capital expenditures were funded through cash that was generated from operations and by borrowings under its credit facility.

We also completed an expansion of our Jay System that extends the pipeline to producers operating in southern Alabama. That expansion consisted of approximately 33 miles of pipeline and gathering connections to approximately 35 wells and includes storage capacity of 20,000 barrels. Including the acquisition of linefill, we expended $2.7 million on this project in 2009. Our expenditures are summarized in the table below.

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Capital Expenditures, and Business and Asset Acquisitions

A summary of our expenditures for fixed assets and other asset acquisitions in the first half of 2009 and 2008 is as follows:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in thousands)	
Capital expenditures for property, plant and equipment:		
Maintenance capital expenditures:		
Pipeline transportation assets	750	165
Supply and logistics assets	720	304
Refinery services assets	544	489
Administrative and other assets	408	26
Total maintenance capital expenditures	2,422	984
Growth capital expenditures:		
Pipeline transportation assets	1,708	3,359
Supply and logistics assets	17,869	4,273
Refinery services assets	1,438	1,221
Total growth capital expenditures	21,015	8,853
Total	23,437	9,837
Capital expenditures for asset purchases:		
Free State Pipeline acquisition	-	75,000
Acquisition of intangible assets	2,500	-
Total asset purchases	2,500	75,000
Capital expenditures attributable to unconsolidated affiliates:		
Faustina project	21	2,210
Total	21	2,210
Total capital expenditures	$25,958	$87,047

During the remainder of 2009, we expect to expend approximately $6.5 million for maintenance capital projects in progress or planned. Those expenditures are expected to include approximately $0.4 million of improvements in our refinery services business, $1.2 million in our crude oil pipeline operations, including $0.7 million for rehabilitation of segments of the Mississippi System as a result of integrity management plan, or IMP testing, $3.0 million related to integration and upgrades of our information technology systems, and the remainder on projects related to our truck transportation operations, including $1.7 million for replacement vehicles. In future years we expect to spend $4 million to $5 million per year on vehicle replacements as the average age of our fleet increases.

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 2009, as shown in the table below (in thousands, except per unit amounts).

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Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
First quarter 2008	May 2008	$ 0.3000	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009 (1)	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326

(1) This distribution will be paid on August 14, 2009 to our general partner and unitholders of record as of August 4, 2009.

See Note 9 of the Notes to the Unaudited Consolidated Financial Statements.

Non-GAAP Reconciliation

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

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

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

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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, 2009 and 2008 is as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Cash flows from operating activities	$15,909	$5,313	$19,066	$22,696
Adjustments to reconcile operating cash flows to Available Cash:				
Maintenance capital expenditures	(1,474)	(208)	(2,422)	(984)
Proceeds from sales of certain assets	52	181	457	426
Amortization of credit facility issuance fees	(481)	(267)	(961)	(535)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	34	329	251	413
Earnings of DG Marine in excess of distributable cash	(904)	-	(2,874)	-
Other items affecting available cash	443	1,722	1,193	1,722
Net effect of changes in operating accounts not included in calculation of Available Cash	8,629	19,115	28,840	18,234
Available Cash before Reserves	$22,208	$26,185	$43,550	$41,972

Commitments and Off-Balance-Sheet Arrangements

Contractual Obligations and Commercial Commitments

There have been no material changes to the commitments and obligations reflected in our Annual Report on Form 10-K for the year ended December 31, 2008.

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” in our Annual Report on Form 10-K for the year ended December 31, 2008, nor do we have any debt or equity triggers based upon our unit or commodity prices.

New 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:

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- 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;
- throughput levels and rates;
- changes in, or challenges to, our tariff rates;
- our ability to successfully identify and consummate strategic acquisitions, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;
- service interruptions in our liquids transportation systems, natural gas transportation systems or natural gas gathering and processing operations;
- shut-downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, natural gas or other products or to whom we sell such products;
- changes in laws or regulations to which we are subject;
- 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 or bankruptcy 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, 2008. 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

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our 2008 Annual Report on Form 10-K. There have been no material changes in that information other than as described below. Also, see Note 15 to our Unaudited Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

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	Sell (Short) Contracts	Buy (Long) Contracts
Futures Contracts:		
Crude Oil:		
Contract volumes (1,000 bbls)	561	185
Weighted average price per bbl	$66.23	$69.63
Contract value (in thousands)	$37,157	12,881
Mark-to-market change (in thousands)	2,257	51
Market settlement value (in thousands)	$39,414	$12,932
Heating Oil:		
Contract volumes (1,000 bbls)	89	12
Weighted average price per gal	$1.93	$1.77
Contract value (in thousands)	$7,221	892
Mark-to-market change (in thousands)	55	9
Market settlement value (in thousands)	$7,276	$901
RBOB Gasoline:		
Contract volumes (1,000 bbls)	10	1
Weighted average price per gal	$1.89	$1.89
Contract value (in thousands)	$794	79
Mark-to-market change (in thousands)	5	-
Market settlement value (in thousands)	$799	$79
NYMEX Option Contracts:		
Crude Oil- Written/Purchased Calls		
Contract volumes (1,000 bbls)	35	-
Weighted average premium received/paid	$2.93	$-
Contract value (in thousands)	$102	$-
Mark-to-market change (in thousands)	32	-
Market settlement value (in thousands)	$134	$-

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.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Information with respect to this item has been incorporated by reference from our Annual Report on Form 10-K for the year ended December 31, 2008. There have been no material developments in legal proceedings since the filing of such Form 10-K.

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, 2008. There have been no material changes to the risk factors since the filing of such Form 10-K.

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

None.

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.)
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 Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009.)
3.7	Certificate of Formation of Genesis Energy, LLC (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 7, 2009.)
3.8	Limited Liability Company Agreement of Genesis Energy, LLC dated December 29, 2008 (incorporated by reference to Exhibit 3.3 to Form 8-K dated January 7, 2009.)
3.9	First Amendment to Limited Liability Company Agreement of Genesis Energy, LLC dated December 31, 2008 (incorporated by reference to Exhibit 3.4 to Form 8-K dated January 7, 2009.)

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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.)
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

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, LLC, as General Partner

Date: August 7, 2009

By: /s/ Robert V. Deere
Robert V. Deere
Chief Financial Officer