GENESIS ENERGY LP
Form 10-Q
August 06, 2010

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

Form 10-Q

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

For the quarterly period ended June 30, 2010

OR

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

Commission file number 1-12295

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

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

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

NONE

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

Yes þ No o

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 o No o

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 o	Accelerated filer þ	Non-accelerated filer o	Smaller reporting company o

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

Yes o No þ

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 2, 2010: 39,585,692

GENESIS ENERGY, L.P.

Form 10-Q

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PART I. FINANCIAL INFORMATION

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$6,033	$4,148
Accounts receivable - trade, net of allowance for doubtful accounts of $1,553 and $1,372 at June 30, 2010 and December 31, 2009, respectively	124,233	127,248
Accounts receivable - related parties	568	2,617
Inventories	83,156	40,204
Investment in direct financing leases, net of unearned income - current portion	4,405	4,202
Other	15,028	10,825
Total current assets	233,423	189,244
FIXED ASSETS, at cost	373,314	373,927
Less: Accumulated depreciation	(98,813)	(89,040)
Net fixed assets	274,501	284,887
INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	170,785	173,027
CO2 ASSETS, net of accumulated amortization	18,129	20,105
EQUITY INVESTEES AND OTHER INVESTMENTS	14,378	15,128
INTANGIBLE ASSETS, net of accumulated amortization	127,179	136,330
GOODWILL	325,046	325,046
OTHER ASSETS, net of accumulated amortization	11,010	4,360
TOTAL ASSETS	$1,174,451	$1,148,127
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$121,835	$114,428
Accounts payable - related parties	1,200	3,197
Accrued liabilities	22,205	23,803
Total current liabilities	145,240	141,428
LONG-TERM DEBT, $44,900 and $46,900 nonrecourse to Genesis Energy, L.P. at June 30, 2010 and December 31, 2009, respectively	404,900	366,900
DEFERRED TAX LIABILITIES	14,639	15,167
OTHER LONG-TERM LIABILITIES	5,519	5,699
COMMITMENTS AND CONTINGENCIES (Note 13)		
PARTNERS' CAPITAL:		

Common unitholders, 39,586 and 39,488 units issued and outstanding, at June 30, 2010 and December 31, 2009, respectively	571,545	585,554
General partner	10,902	11,152
Accumulated other comprehensive loss	(653)	(829)
Total Genesis Energy, L.P. partners' capital	581,794	595,877
Noncontrolling interests	22,359	23,056
Total partners' capital	604,153	618,933
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$1,174,451	$1,148,127

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

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
REVENUES:				
Supply and logistics:				
Unrelated parties	$400,612	$290,236	$820,314	$478,054
Related parties	249	1,128	646	2,372
Refinery services	38,221	34,594	67,723	82,888
Pipeline transportation, including natural gas sales:				
Transportation services - unrelated parties	12,895	4,032	22,777	7,433
Transportation services - related parties	-	7,904	2,861	16,198
Natural gas sales revenues	530	519	1,445	1,232
CO2 marketing:				
Unrelated parties	3,259	3,057	5,995	6,109
Related parties	772	734	1,308	1,411
Total revenues	456,538	342,204	923,069	595,697
COSTS AND EXPENSES:				
Supply and logistics costs:				
Product costs - unrelated parties	369,228	266,313	761,419	430,044
Product costs - related parties	-	41	-	1,754
Operating costs	20,848	17,921	43,464	35,190
Operating costs - related parties	1,333	-	1,333	-
Refinery services operating costs	21,790	21,218	38,017	56,551
Pipeline transportation costs:				
Pipeline transportation operating costs	2,621	2,638	6,185	5,132
Natural gas purchases	492	470	1,357	1,124
CO2 marketing costs:				
Transportation costs	1,567	1,341	2,801	2,648
Other costs	15	15	31	31
General and administrative	6,801	8,306	13,095	17,060
Depreciation and amortization	13,606	16,133	27,012	31,552
Net (gain) loss on disposal of surplus assets	(62)	60	18	(158)
Total costs and expenses	438,239	334,456	894,732	580,928
OPERATING INCOME	18,299	7,748	28,337	14,769
Equity in earnings of joint ventures	363	264	545	2,170
Interest expense	(3,760)	(3,373)	(6,964)	(6,408)
Income before income taxes	14,902	4,639	21,918	10,531
Income tax expense	(981)	(817)	(1,672)	(1,408)
NET INCOME	13,921	3,822	20,246	9,123
Net loss attributable to noncontrolling interests	317	634	877	623
	$14,238	$4,456	$21,123	$9,746

NET INCOME ATTRIBUTABLE TO GENESIS
ENERGY, L.P.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:				
BASIC AND DILUTED	$0.29	$0.13	$0.36	$0.29

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income	$13,921	$3,822	$20,246	$9,123
Change in fair value of derivatives:				
Current period reclassification to earnings	279	158	559	290
Changes in derivative financial instruments - interest rate swaps	4	43	(200)	(85)
Comprehensive income	14,204	4,023	20,605	9,328
Comprehensive loss (income) attributable to noncontrolling interests	172	(103)	694	(106)
Comprehensive income attributable to Genesis Energy, L.P.	$14,376	$3,920	$21,299	$9,222

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

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GENESIS ENERGY, L.P.
UNAUDITED CONDENSED 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, 2010	39,488	$ 585,554	$ 11,152	$ (829)	$ 23,056	$ 618,933
Comprehensive income:						
Net income (loss)	-	14,770	6,353	-	(877)	20,246
Interest rate swap losses reclassified to interest expense	-	-	-	274	285	559
Interest rate swap loss	-	-	-	(98)	(102)	(200)
Cash contributions	-	-	37	-	-	37
Cash distributions	-	(28,799)	(4,964)	-	(3)	(33,766)
Contribution for executive compensation (See Note 9)	-	-	(1,676)	-	-	(1,676)
Unit based compensation expense	98	20	-	-	-	20
Partners' capital, June 30, 2010	39,586	$ 571,545	$ 10,902	$ (653)	$ 22,359	$ 604,153

	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 (loss)	-	12,051	(2,305)	-	(623)	9,123
Interest rate swap loss 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 9)	-	-	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

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

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

	Six Months Ended June 30,	
	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$20,246	$9,123
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation of fixed assets	11,701	13,082
Amortization of intangible and CO2 assets	15,311	18,470
Amortization and write-off of credit facility issuance costs	1,269	961
Amortization of unearned income and initial direct costs on direct financing leases	(8,873)	(9,092)
Payments received under direct financing leases	10,926	10,927
Equity in earnings of investments in joint ventures	(545)	(2,170)
Distributions from joint ventures - return on investment	1,122	800
Non-cash effect of unit-based compensation plans	72	1,489
Non-cash compensation charge	(1,676)	4,499
Deferred and other tax liabilities	414	1,087
Other non-cash items	(802)	(1,270)
Net changes in components of operating assets and liabilities (See Note 10)	(38,452)	(28,840)
Net cash provided by operating activities	10,713	19,066
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(5,980)	(26,597)
Distributions from joint ventures - return of investment	180	-
Other, net	640	557
Net cash used in investing activities	(5,160)	(26,040)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings	345,029	130,300
Bank repayments	(307,029)	(106,200)
Credit facility issuance fees	(7,428)	-
General partner contributions	37	6
Noncontrolling interests distributions	(3)	(3)
Distributions to common unitholders	(28,799)	(26,338)
Distributions to general partner interest	(4,964)	(2,485)
Other, net	(511)	(362)
Net cash used in financing activities	(3,668)	(5,082)
Net increase (decrease) in cash and cash equivalents	1,885	(12,056)
Cash and cash equivalents at beginning of period	4,148	18,985
Cash and cash equivalents at end of period	$6,033	$6,929

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

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED 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 crude oil and petroleum products by trucks and barges; 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. 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

Our 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 condensed 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, 2009.

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

2. Consolidated Joint Venture – DG Marine

We formed DG Marine Transportation, LLC (DG Marine) as a joint venture with TD Marine (a related party) in 2008. TD Marine owned (indirectly) a 51% economic interest in DG Marine, and we owned (directly and indirectly) a 49% economic interest. DG Marine gives us the capability to provide transportation services of petroleum products by barge and complements our other supply and logistics operations. On July 28 2010, we acquired TD Marine's effective 51% interest in DG Marine, resulting in DG Marine becoming wholly-owned by us. In connection with this transaction, we paid off DG Marine's outstanding debt under its stand-alone credit facility. See Note 14.

Until July 28, 2010, DG Marine was a variable interest entity ("VIE") as certain of our voting rights were not proportional to our 49% economic interest. Accounting provisions require the primary beneficiary to consolidate VIEs. In determining the primary beneficiary of a VIE that is held between two or more related parties the primary beneficiary is considered to be the party that is "most closely associated" with the VIE. We were considered to be the primary beneficiary due to (i) our involvement in the design of DG Marine, (ii) the ongoing involvement with regards to financial and operating decision making of DG Marine, excluding matters related to new contracts and vessel disposal which are decided solely by TD Marine, and (iii) the financial support we provide to DG Marine. TD Marine has no requirements to make any additional contributions to DG Marine.

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

We have entered into a subordinated loan agreement with DG Marine whereby we may (at our sole discretion) lend up to $25 million to DG Marine. The loan agreement provides for DG Marine to pay us interest on any loans at the 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 principal and interest payments under our subordinated loan agreement and distributions in respect of our equity interest. At both June 30, 2010 and December 31, 2009, $25 million was outstanding under the subordinated loan agreement; however this amount was eliminated in consolidation. Due to the credit facility restrictions, no interest payments were made by DG Marine to us during the six months ended June 30, 2010. The proceeds of the loan were used to reduce the amount outstanding under the DG Marine credit facility. Additionally, at June 30, 2010 and December 31, 2009, Genesis had provided a $7.5 million guaranty to the lenders under the DG Marine credit facility.

At June 30, 2010 and December 31, 2009, our condensed consolidated balance sheets included the following amounts related to DG Marine:

	June 30, 2010	December 31, 2009
Cash	$ 1,597	$ 585
Accounts receivable - trade	3,167	3,216
Other current assets	1,127	2,421
Fixed assets, at cost	124,360	124,276
Accumulated depreciation	(12,383)	(9,139)
Intangible assets, net	1,567	1,758
Other assets, net	794	1,174
Total assets	$ 120,229	$ 124,291
Accounts payable, trade	$ 1,191	$ 1,788
Accrued liabilities	3,119	3,601
Long-term debt	44,900	46,900
Other long-term liabilities	255	683
Total liabilities	$ 49,465	$ 52,972

3. Inventories

The major components of inventories were as follows:

	June 30, 2010	December 31, 2009
Crude oil	$ 17,340	$ 13,901
Petroleum products	60,244	22,150
Caustic soda	1,761	1,985
NaHS	3,806	2,154
Other	5	14
Total inventories	$ 83,156	$ 40,204

Inventories are valued at the lower of cost or market. The costs of inventories exceeded market values by approximately $0.2 million at June 30, 2010, and we reduced the value of inventory in our unaudited condensed consolidated financial statements for this difference. The costs of inventories did not exceed market values at December 31, 2009.

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

4. Intangible Assets and Goodwill

Intangible Assets

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

	June 30, 2010			December 31, 2009		
	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Customer relationships:						
Refinery services	$94,654	$ 47,295	$47,359	$94,654	$ 41,450	$53,204
Supply and logistics	35,430	17,737	17,693	35,430	15,493	19,937
Supplier relationships -						
Refinery services	36,469	30,014	6,455	36,469	28,551	7,918
Licensing Agreements -						
Refinery services	38,678	13,733	24,945	38,678	11,681	26,997
Trade names -						
Supply and logistics	18,888	6,487	12,401	18,888	5,444	13,444
Favorable lease -						
Supply and logistics	13,260	1,381	11,879	13,260	1,144	12,116
Other	8,008	1,561	6,447	3,823	1,109	2,714
Total	$245,387	$ 118,208	$127,179	$241,202	$ 104,872	$136,330

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 2010	$ 13,497
2011	$ 21,918
2012	$ 18,261
2013	$ 14,264
2014	$ 11,790
2015	$ 9,856

Goodwill

The carrying amount of goodwill by business segment at both June 30, 2010 and December 31, 2009 was $301.9 million to refinery services and $23.1 million to supply and logistics.

5. Debt

Our obligations under credit facilities consisted of the following:

	June 30, 2010	December 31, 2009
Genesis Credit Facility, variable rate, due June 2015	$ 360,000	$ 320,000
DG Marine Credit Facility, variable rate, due July 2011	44,900	46,900
Total Long-Term Debt	$ 404,900	$ 366,900

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

On June 29, 2010, we restructured our senior secured credit agreement with a syndicate of banks led by BNP Paribas. Among other changes, our credit agreement:

- Now matures on June 30, 2015;
- provides for a $525 million senior secured revolving credit facility, with the ability to increase the size of the facility up to $650 million, with approval of lenders;
- includes a $75 million petroleum products inventory loan sublimit; and
- no longer includes "borrowing base" limitations except with respect to inventory loans.

Our inventory borrowing base is recalculated monthly. At June 30, 2010, our inventory borrowing base was $37.9 million.

At June 30, 2010, we had $360.0 million borrowed under our credit agreement, with $37.9 million of that amount designated as a loan under the inventory sublimit. Additionally, we had $4.3 million in letters of credit outstanding.

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

- The interest rate on borrowings may be based on a eurodollar rate ("LIBOR") or an Alternate Base Rate ("ABR"), at our option. The interest rate on LIBOR borrowings is equal to the sum of (a) the LIBOR rate for the applicable interest period multiplied by the statutory reserve rate and (b) a margin that can range from 2.50% to 3.50%. The interest rate on ABR borrowings is equal to the sum of (a) the greatest of (i) the prime rate established by BNP Paribas, (ii) the federal funds effective rate plus ½ of 1% and (iii) the LIBOR rate for a one-month maturity plus 1%, and (b) a margin that can range from 1.50% to 2.50%. The applicable margin under either option is based on our leverage ratio as computed under our credit agreement. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At June 30, 2010, our borrowing rate margins were 2.75% and 1.75% for LIBOR and ABR borrowings, respectively.

- Letter of credit fees will range from 2.50% to 3.50% based on our leverage ratio as computed under our credit agreement. This rate can fluctuate quarterly. At June 30, 2010, our letter of credit rate was 2.75%.

- We pay a commitment fee on the unused portion of the $525 million facility amount. The commitment fee is 0.50%.

Collateral under the credit facility consists of substantially all of our assets, excluding our security interest in the NEJD pipeline and our ownership interest in the Free State pipeline. Our credit agreement is recourse to our general partner only with respect to its general partner interest in certain of our subsidiaries.

Our credit agreement contains customary covenants (affirmative, negative and financial) that limit the manner in which we may conduct our business. Our credit agreement contains three primary financial covenants – a maximum leverage ratio, a maximum senior secured leverage ratio and a minimum interest coverage ratio. In general, our leverage ratio calculations compare our consolidated funded debt (excluding the amounts borrowed under the inventory sublimit in our credit agreement) to EBITDA (as defined and adjusted in accordance with our credit agreement). Our interest coverage ratio compares EBITDA (as adjusted) to interest expense. Our credit agreement includes provisions for the temporary adjustment of the required ratios following material acquisitions and with lender approval. So long as we are in compliance with the terms of our credit agreement, we have no limitations on our ability to distribute all of our available cash (as defined in our partnership agreement). We were in compliance with all applicable covenants of our credit

The DG Marine revolving credit facility is non-recourse to us and TD Marine (other than with respect to each of their investments in DG Marine). Although DG Marine's debt is non-recourse to us, our ownership interest in DG Marine is pledged to secure its indebtedness. In connection with our purchase of TD Marine's interest in DG Marine on July 29 2010, we paid off the balance outstanding on the DG Marine credit facility. See Note 14.

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

We were in compliance with all applicable covenants of our credit agreement and the DG Marine credit facility at June 30, 2010.

We are unable to estimate the fair value of the debt under our revolving credit facilities due to the potential variability of expected outstanding balances under the facilities; however we believe the amounts included in our balance sheet approximate fair value due to the recent restructuring of our credit agreement.

6. Distributions and Net Income Per Common Unit

Distributions

We paid or will pay the following distributions in 2009 and 2010:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326
Third quarter 2009	November 2009	$ 0.3525	$ 13,918	$ 284	$ 1,729	$ 15,931
Fourth quarter 2009	February 2010	$ 0.3600	$ 14,251	$ 291	$ 2,037	$ 16,579
First quarter 2010	May 2010	$ 0.3675	$ 14,548	$ 297	$ 2,339	$ 17,184
Second quarter 2010	August 2010 (1)	$ 0.3750	$ 14,845	$ 303	$ 2,642	$ 17,790

(1) This distribution will be paid on August 13, 2010 to our general partner and unitholders of record as of August 3, 2010.

Net Income Allocation to Partners

Net income is allocated to our partners in the Unaudited Condensed 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 9).
-

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.

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

Net Income Per Common Unit

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,	
	2010	2009	2010	2009
Numerators for basic and diluted net income per common unit:				
Income attributable to Genesis Energy, L.P.	$14,238	$4,456	$21,123	$9,746
Less: General partner's incentive distribution to be paid for the period	(2,642)	(1,427)	(4,981)	(2,552)
Add: Expense (Credit) for Class B and Series B Awards (Note 9)	301	2,353	(1,676)	4,499
Subtotal	11,897	5,382	14,466	11,693
Less: General partner 2% ownership	(238)	(108)	(289)	(234)
Income available for common unitholders	$11,659	$5,274	$14,177	$11,459
Denominator for basic per common unit:				
Common Units	39,586	39,464	39,567	39,460
Denominator for diluted per common unit:				
Common Units	39,586	39,464	39,567	39,460
Phantom Units (1)	-	154	24	132
	39,586	39,618	39,591	39,592
Basic net income per common unit	$0.29	$0.13	$0.36	$0.29
Diluted net income per common unit	$0.29	$0.13	$0.36	$0.29

(1) See Note 9 for description of Phantom Units.

7. Business Segment Information

We define Segment Margin as revenues less product costs, 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	Total
Three Months Ended June 30, 2010					
Segment margin (a)	$ 11,437	$16,190	$7,221	$3,001	$37,849
Maintenance capital expenditures	$ 78	$356	$484	$-	$918
Revenues:					
External customers	$ 11,498	$40,348	$400,661	$4,031	$456,538
Intersegment (b)	1,927	(2,127)	200	-	-
Total revenues of reportable segments	$ 13,425	$38,221	$400,861	$4,031	$456,538
Three Months Ended June 30, 2009					
Segment margin (a)	$ 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 (b)	1,572	(1,329)	(243)	-	-
Total revenues of reportable segments	$ 12,455	$34,594	$291,364	$3,791	$342,204

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	Pipeline Transportation	Refinery Services	Supply & Logistics	Industrial Gases	Total
Six Months Ended June 30, 2010					
Segment margin (a)	$ 21,836	$29,450	$11,733	$5,495	$68,514
Maintenance capital expenditures	$ 134	$815	$594	$-	$1,543
Revenues:					
External customers	$ 22,910	$71,718	$821,138	$7,303	$923,069
Intersegment (b)	4,173	(3,995)	(178)	-	-
Total revenues of reportable segments	$ 27,083	$67,723	$820,960	$7,303	$923,069
Six Months Ended June 30, 2009					
Segment margin (a)	$ 20,572	$25,949	$12,556	$5,892	$64,969
Maintenance capital expenditures	$ 750	$544	$1,128	$-	$2,422
Revenues:					
External customers	$ 22,198	$85,828	$480,151	$7,520	$595,697
Intersegment (b)	2,665	(2,940)	275	-	-
Total revenues of reportable segments	$ 24,863	$82,888	$480,426	$7,520	$595,697

(a) A reconciliation of Segment Margin to income before income taxes for the periods presented is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Segment Margin	$37,849	$33,006	$68,514	$64,969
Corporate general and administrative expenses	(5,975)	(7,576)	(11,405)	(15,077)
Depreciation and amortization	(13,606)	(16,133)	(27,012)	(31,552)
Net gain (loss) on disposal of surplus assets	62	(60)	(18)	158
Interest expense, net	(3,760)	(3,373)	(6,964)	(6,408)
Non-cash expenses (credits) not included in segment margin	1,559	(126)	1,335	(842)
Other non-cash items affecting segment margin	(1,227)	(1,099)	(2,532)	(717)
Income before income taxes	$14,902	$4,639	$21,918	$10,531

(b) Intersegment sales were conducted on an arm’s length basis.

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8. 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. An affiliate of Denbury Resources, Inc. sold its interest in our general partner on February 5, 2010. Transactions with Denbury are included in the table below as related party transactions through February 5, 2010.

The transactions with related parties were as follows:

	Six Months Ended June 30, 2010	2009
Operations, general and administrative services provided by our general partner	$ 23,131	$ 27,645
Marine operating costs provided by Quintana affiliate	$ 1,333	$ -
Sales of CO2 to Sandhill	$ 1,308	$ 1,411
Petroleum products sales to Davison family businesses	$ 464	$ 390
Truck transportation services provided to Denbury	$ 182	$ 1,982
Pipeline transportation services provided to Denbury	$ 1,365	$ 7,047
Payments received under direct financing leases from Denbury	$ 99	$ 10,927
Pipeline transportation income portion of direct financing lease fees from Denbury	$ 1,502	$ 9,191
Pipeline monitoring services provided to Denbury	$ 10	$ 60
Directors' fees paid to Denbury	$ -	$ 110
CO2 transportation services provided by Denbury	$ 373	$ 2,507
Crude oil purchases from Denbury	$ -	$ 1,754

Amounts due to and from Related Parties

At June 30, 2010 and December 31, 2009, we owed our general partner $1.0 million and $2.1 million for administrative services, respectively. We owed an affiliate of Quintana Capital Group II, L.P. $0.2 million at June 30, 2010 for fuel and other expenses associated with our inland marine barge operations. Sandhill owed us $0.5 million and $0.7 million for purchases of CO2 at June 30, 2010 and December 31, 2009, respectively. Denbury owed us $1.9 million for truck and pipeline transportation services and we owed Denbury $1.0 million for CO2 transportation charges at December 31, 2009.

9. Equity-Based Compensation

We recorded charges and credits related to our equity-based compensation plans and awards for the three and six months ended June 30, 2010 and 2009 as follows:

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Expense (Credits) Related to Equity-Based Compensation

Statement of Operations	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Pipeline operating costs	$21	$51	$108	$84
Refinery services operating costs	(4)	74	174	150
Supply and logistics operating costs	(75)	219	294	429
General and administrative expenses	320	2,821	(1,010)	5,331
Total	$262	$3,165	$(434)	$5,994

In connection with the sale of our general partner on February 5, 2010, our general partner redeemed all of its Class B Member Interests and replaced its Class A Member Interest with Series A units and Series B units.

Series B Units

Our general partner uses the Series B Units, which have no voting rights, as part of its long-term compensation structure for our management team. A total of 1,000 Series B Units may be issued by our general partner. Pursuant to restricted unit agreements entered into with Genesis Energy, LLC, our general partner, on February 5, 2010, certain members of our management team received an aggregate of 767 Series B units in our general partner. The Series B Units will be converted into Series A Units on the seventh anniversary of the issuance date of the awards (unless a conversion occurs at a prior date due to a public offering or a change in control of our general partner) as long as the award recipients remain in service.

Subject to the rights of the holders of the Series A units in our general partner to receive distributions up to certain threshold amounts, holders of Series B units, upon vesting, have the right to receive a share of the distributions paid by us to our general partner. With regard to the right to receive a share of distributions, the Series B Units vest 25% per year on each of the next four anniversary dates of the award. The four-year vesting requirement would also be applicable to any conversion due to a public offering should that conversion occur in the first four years after issuance of the award.

Although the Series B units represent an equity interest in our general partner and our general partner will not seek reimbursement under our partnership agreement for the value of these compensation arrangements, we will record non-cash expense for the estimated fair value of the awards. The estimated fair value of the converted Series B units will be recomputed at each quarterly reporting date until conversion, and the expense to be recorded will be adjusted based on that fair value, with an offsetting entry to the capital account of our general partner.

Management's estimates of the fair value of these awards are based on a number of future events, including estimates of the distributions that would be received by our general partner in the future through the conversion date of February 5, 2017, the fair value of our general partner at February 5, 2017, and assumptions about an appropriate discount rate. Changes in our assumptions will change the amount of expense we record.

At June 30, 2010, management estimates that the fair value of the Series B Units granted to our management team is approximately $8.4 million. This estimate of the fair value was determined using a discount rate of 20%, representing the risks inherent in the assumptions we used and the time value until final conversion of the Series B Units. Due to the limited number of holders of Series B Units, we assumed a forfeiture rate of zero. For the three and six months ended June 30, 2010, we recorded non-cash expense of $0.3 million and $0.5 million, respectively for these awards.

2007 Long Term Incentive Plan

As a result of the sale of our general partner on February 5, 2010, all outstanding phantom units issued pursuant to our 2007 Long Term Incentive Plan vested. As a result of this acceleration of the vesting period, we recorded non-cash compensation expense of $0.5 million in the first quarter of 2010. In total, 123,857 phantom units vested.

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Class B Membership Interests

All of the Class B membership interests in our general partner held by the existing management team were either (i) converted into Series A units in our general partner or (ii) redeemed by our general partner on February 5, 2010. The amounts owed under the deferred compensation plan with the management team were similarly converted or redeemed. In total, the value of the Series A units issued and cash payments made by our general partner to settle its obligations under the Class B membership interests and deferred compensation totaled $14.9 million. This value, when combined with amounts previously paid to our management team during 2009 related to the Class B membership interests, resulted in total compensation expense of $15.4 million. The difference between the recorded cumulative compensation expense related to these interests through December 31, 2009 of $17.5 million and the total compensation expense of $15.4 million was recorded as a reduction of expense in the first quarter of 2010.

2010 Long Term Incentive Plan

In the second quarter of 2010, our general partner adopted the Genesis Energy, LLC 2010 Long-Term Incentive Plan (the “2010 Plan”). The 2010 Plan provides for the awards of phantom units and distribution equivalent rights to directors of our general partner, and employees and other representatives of our general partner and its affiliates who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. Distribution equivalent rights (“DERs”) are tandem rights to receive on a quarterly basis an amount of cash equal to the amount of distributions that would have been paid on the phantom units had they been limited partner units issued by us. The 2010 Plan is administered by the Governance, Compensation and Business Development Committee (the “GCBD Committee”) of the board of directors of our general partner.

The GCBD Committee (at its discretion) will designate participants in the 2010 Plan, determine the types of awards to grant to participants, determine the number of units to be covered by any award, and determine the conditions and terms of any award including vesting, settlement and forfeiture conditions. The GCBD Committee made the initial awards of 44,829 phantom units with tandem DERs under the 2010 Plan in April 2010. The phantom units will vest on the third anniversary of the date of issuance.

The compensation cost associated with the phantom units is re-measured each reporting period based on the fair value of the phantom units, and the liability recorded for the estimated amount to be paid to the participants will be adjusted. Management’s estimates of the fair value of these awards include assumptions about expectation of forfeitures prior to vesting. Due to the positions of the small group of employees and non-employee directors who received these awards, we have assumed that there will be no forfeitures of these phantom units in our fair value calculation as of June 30, 2010. At June 30, 2010, we estimate the fair value of these awards to be approximately $0.8 million, and we recorded $0.1 million of compensation expense related to the awards in the second quarter of 2010.

10. Supplemental Cash Flow Information

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

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	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Decrease (increase) in:		
Accounts receivable	$ 4,870	$ (7,606)
Inventories	(45,008)	(13,385)
Other current assets	(1,042)	(5,864)
Increase (decrease) in:		
Accounts payable	5,302	3,310
Accrued liabilities	(2,574)	(5,295)
Net changes in components of operating assets and liabilities, net of working capital acquired	$ (38,452)	$ (28,840)

Cash received by us for interest for the six months ended June 30, 2010 and 2009 was less than $0.1 million. Payments of interest and commitment fees were $6.1 million and $7.8 million for the six months ended June 30, 2010 and 2009, respectively.

Cash paid for income taxes during the six months ended June 30, 2010 and 2009 was $2.0 million and $1.6 million, respectively.

At June 30, 2010, we had incurred liabilities for fixed asset and other asset additions totaling $1.1 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” under investing activities on the Unaudited Condensed Consolidated Statements of Cash Flows. At June 30, 2009, we had incurred $1.5 million of such liabilities that had not been paid at that date and are not included in “Payments to acquire fixed and intangible assets” under investing activities.

11. Derivatives

Commodity Derivatives

At June 30, 2010, we had the following outstanding derivative commodity futures, forwards and options contracts that were entered into to hedge inventory or fixed price purchase commitments:

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	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	179	-
Weighted average contract price per bbl	$ 80.40	$ -
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	494	62
Weighted average contract price per bbl	$ 76.64	$ 76.50
Heating oil futures:		
Contract volumes (1,000 bbls)	70	17
Weighted average contract price per gal	$ 2.18	$ 2.29
RBOB gasoline futures:		
Contract volumes (1,000 bbls)	20	-
Weighted average contract price per gal	$ 2.01	$ -
#6 Fuel oil futures:		
Contract volumes (1,000 bbls)	140	35
Weighted average contract price per bbl	$ 65.12	$ 64.20
Crude oil written calls:		
Contract volumes (1,000 bbls)	153	-
Weighted average premium received	$ 2.46	$ -

Interest Rate Derivatives

DG Marine utilizes swap contracts with financial institutions to hedge interest payments for $32.9 million of its outstanding debt through July 2011. The weighted average interest rate of these swap contracts at June 30, 2010 was 4.53%. DG Marine expected these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates; therefore, we designated these swap contracts as cash flow hedges under accounting guidance. The effective portion of the derivative represents the change in fair value of the hedge that offsets the change in cash flows of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts was reported as a component of Accumulated Other Comprehensive Loss (AOCL) and reclassified into future earnings contemporaneously as interest expense associated with the underlying debt under the DG Marine credit facility was recorded. To the extent that the change in the fair value of the interest rate swaps did 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 Condensed Consolidated Statements of Operations. In the third quarter of 2010, we settled the DG Marine interest rate swaps in connection with our acquisition of the 51% of DG Marine that we did not own. See Note 14.

Financial Statement Impacts

The following tables reflect the estimated fair value gain (loss) position of our hedge derivatives and related inventory impact for qualifying hedges at June 30, 2010 and December 31, 2009:

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Fair Value of Derivative Assets and Liabilities

	Unaudited Condensed Consolidated Balance Sheets Location	Asset Derivatives Fair Value June 30, 2010	December 31, 2009
Commodity derivatives - futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other Current Assets	$ 852	$ 53
Undesignated hedges	Other Current Assets	1,354	307
Total asset derivatives		$ 2,206	$ 360

	Unaudited Condensed Consolidated Balance Sheets Location	Liability Derivatives Fair Value June 30, 2010	December 31, 2009
Commodity derivatives - futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other Current Assets	$ (18) (1)	$ (159)
Undesignated hedges	Other Current Assets	(944) (1)	(2,118)
Total commodity derivatives		(962)	(2,277)
Interest rate swaps designated as cash flow hedges under accounting rules:			
Portion expected to be reclassified into earnings within one year	Accrued Liabilities	(1,254)	(1,176)
Portion expected to be reclassified into earnings after one year	Other Long-term Liabilities	(75)	(512)
Total liability derivatives		$ (2,291)	$ (3,965)

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

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	Effect on Unaudited Condensed Consolidated Statements of Operations and Other Comprehensive Income — Amount of Gain (Loss) Recognized in Income					
	Supply & Logistics Product Costs Three Months Ended June 30,		Interest Expense Reclassified from AOCI Three Months Ended June 30,		Other Comprehensive Income Effective Portion Three Months Ended June 30,	
	2010	2009	2010	2009	2010	2009
Commodity derivatives - futures and call options:						
Contracts designated as hedges under accounting guidance	$1,032	$(4,323)	$-	$-	$-	$-
Contracts not considered hedges under accounting guidance	4,977	(2,545)	-	-	-	-
Total commodity derivatives	6,009	(6,868)	-	-	-	-
Interest rate swaps designated as cash flow hedges under accounting guidance	-	-	(279)	(158)	4	43
Total derivatives	$6,009	$(6,868)	$(279)	$(158)	$4	$43

	Effect on Unaudited Condensed Consolidated Statements of Operations and Other Comprehensive Income — Amount of Gain (Loss) Recognized in Income					
	Supply & Logistics Product Costs Six Months Ended June 30,		Interest Expense Reclassified from AOCI Six Months Ended June 30,		Other Comprehensive Income Effective Portion Six Months Ended June 30,	
	2010	2009	2010	2009	2010	2009
Commodity derivatives - futures and call options:						
Contracts designated as hedges under accounting guidance	$1,306 (1)	$(4,852) (1)	$-	$-	$-	$-
Contracts not considered hedges under accounting guidance	4,425	(2,363)	-	-	-	-
Total commodity derivatives	5,731	(7,215)	-	-	-	-
Interest rate swaps designated as cash flow hedges under accounting guidance	-	-	(559)	(290)	(200)	(85)

Total derivatives	$5,731	$(7,215)	$(559)	$(290)	$(200)	$(85)

(1) Represents the amount of gain (loss) recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the loss recorded on the hedged inventory under the fair value hedge of $0.3 million for the six months ended June 30, 2010 and excludes the gain on the hedged inventory under the fair value hedge of $6.2 million for the six months ended June 30, 2009.

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During the first six months of 2010 and 2009, DG Marine's interest rate hedges fully offset the hedged risk; therefore, there was no ineffectiveness recorded for the hedges.

We expect to reclassify $1.3 million in unrealized losses from AOCL into interest expense during the third quarter of 2010 as a result of the settlement of the interest rate swaps. See Note 14. We have no derivative contracts with credit contingent features.

12. 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, 2010. As required by fair value accounting guidance, 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, 2010			Fair Value at December 31, 2009		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$2,206	$-	$-	$360	$-	$-
Liabilities	$(962)	$-	$-	$(2,277)	$-	$-
Interest rate swaps - Liabilities	$-	$-	$(1,329)	$-	$-	$(1,688)

Level 1

Included in Level 1 of the fair value hierarchy as 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, 2010, 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:

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Balance at beginning of period	(1,612)	(1,960)	(1,688)	(1,964)
Realized and unrealized gains (losses)-				
Reclassified into interest expense	279	158	559	290
Included in other comprehensive income	4	43	(200)	(85)
Balance at end of period	$(1,329)	$(1,759)	$(1,329)	$(1,759)
Total amount of losses for the six months ended included in earnings attributable to the change in unrealized losses relating to contracts still held at June 30, 2010 and 2009, respectively			$(10)	$(13)

See Note 11 for additional information on our derivative instruments.

We generally apply fair value techniques on a non-recurring basis associated with (1) valuing potential impairment loss related to goodwill, (2) valuing asset retirement obligations, and (3) valuing potential impairment loss related to long-lived assets.

13. Contingencies

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

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.

14. Subsequent Event

On July 28, 2010, we acquired the 51% interest of DG Marine that we did not own for $25.5 million in cash. We now own 100% of DG Marine.

We funded the acquisition with proceeds from our credit agreement, including (i) paying off DG Marine's stand-alone credit facility, which had an outstanding principal balance of $44.4 million, and (ii) settling DG Marine's interest rate swaps, which will result in $1.3 million being reclassified from Accumulated Other Comprehensive Loss to interest expense in the third quarter of 2010.

The transaction was unanimously approved by all of the members of the Board of Directors of our general partner who attended the meeting to review the transaction and who voted on the transaction. The Board's approval was based, in part, on the unanimous approval and recommendation of the Conflicts Committee of that Board. The Conflicts Committee engaged as its financial advisor, and obtained a fairness opinion from, Robert W. Baird & Co. The Conflicts Committee also engaged independent legal counsel.

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

In the discussions that follow, we will focus on our revenues, expenses and net income, as well as 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. We define segment margin as revenues less product costs, 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 equity-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 before income taxes is included in our segment disclosures in Note 7 to our unaudited condensed 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 equity investees in lieu of our equity income attributable to such equity investees, the elimination of gains and losses on asset sales (except those from the sale of surplus assets), the elimination of earnings of DG Marine in excess of distributable cash 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 2010, we reported net income attributable to the partnership of $14.2 million, or $0.29 per common unit. We generated $26.1 million of Available Cash before Reserves, and we will distribute $17.8 million to holders of our common units and general partner for the second quarter. During the second quarter of 2010, cash utilized in operating activities was $2.6 million, which we believe is the most directly comparable GAAP financial measure to Available Cash before Reserves.

On July 13, 2010, we increased our quarterly distribution rate to our common unitholders for the twentieth consecutive quarter. We will pay a distribution in August 2010 attributable to the second quarter of 2010 of $0.375 per unit, which represents an approximate 8.7% increase from our distribution of $0.345 per unit for the second quarter of 2009. We paid a distribution in May 2010 attributable to the first quarter of 2010 of $0.3675 per unit.

On June 29, 2010, we restructured our senior secured credit facility. Our credit facility now provides for a $525 million senior secured revolving credit facility, includes an accordion feature whereby the total credit available can be increased up to $650 million under certain circumstances, and matures on June 30, 2015. Among other modifications, our credit facility now includes a $75 million sublimit tranche designed for more efficient financing of crude oil and petroleum products inventory. Our old credit facility was scheduled to mature in November 2011. See additional discussion under Liquidity and Capital Resources – Capital Resources/Sources of Cash below and in Note 5 to our unaudited condensed consolidated financial statements.

We believe our current cash balances, 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 absence of any need to access the capital markets (other than opportunistically) may allow us to take advantage of acquisition and/or growth opportunities that may develop.

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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 due to limitations in our ability to consummate future debt or equity financings. We also will 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:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
	(in thousands)	
Net income attributable to Genesis Energy, L.P.	$ 14,238	$ 4,456
Depreciation and amortization	13,606	16,133
Cash received from direct financing leases not included in income	1,038	929
Cash effects of sales of certain assets	795	52
Effects of available cash generated by equity method investees not included in income	188	170
Cash effects of equity-based compensation plans	(117)	(3)
Non-cash tax expense	228	627
Earnings of DG Marine in excess of distributable cash	(1,481)	(904)
Non-cash equity-based compensation benefit	246	3,165
Other non-cash items, net	(1,748)	(943)
Maintenance capital expenditures	(918)	(1,474)
Available Cash before Reserves	$ 26,075	$ 22,208

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the most comparable GAAP measure) for the three months ended June 30, 2010 and 2009 in Liquidity and Capital Resources – Non-GAAP Reconciliation below. For the three months ended June 30, 2010, cash flows utilized in operating activities were $2.6 million. For the three months ended June 30, 2009, cash flows provided by operating activities were $15.9 million.

Results of Operations

Revenues, Costs and Expenses and Net Income

Our revenues for the three months ended June 30, 2010 increased $114 million, or 33% from the second quarter of 2009. Additionally, our costs and expenses increased $104 million, or 31% between the two periods. The majority of our revenues and costs are derived from the purchase and sale of crude oil and petroleum products. The increase in our revenues and costs between the two second quarter periods is primarily attributable to the fluctuations in the market prices for crude oil and petroleum products realized by our supply and logistics segment. In the second quarter of 2010, average closing prices for West Texas Intermediate crude oil on the New York Mercantile Exchange averaged $78.03 per barrel, as compared to $59.62 per barrel in the second quarter of 2009 – an increase of 31%. Net income (attributable to us) increased $9.8 million, or 220%, between the second quarter of 2009 and the same period in 2010. The significant factors affecting net income were improved operating results by all of our business segments as compared to the second quarter of 2009 and a net reduction in our non-cash general and administrative expenses for 2010 resulting from the sale of our general partner, which reduction was comprised of a decrease in the amount of our non-cash executive compensation and equity-based compensation resulting from our general partner's redemption of certain equity interests, partially offset by other transaction related costs. A more detailed discussion of our segment results and other costs are included below.

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Our revenues for the six months ended June 30, 2010 increased $327 million, or 55% from the six months ended June 30, 2009. Additionally, our costs and expenses increased $314 million, or 54% between the two periods. This increase in our revenues and costs between the two periods is primarily due to fluctuations in the market prices for crude oil and petroleum products. In the first half of 2010, average closing prices for West Texas Intermediate crude oil on the New York Mercantile Exchange averaged $78.37 per barrel, as compared to $51.35 per barrel in the first half of 2009 – an increase of 53%. Net income (attributable to us) increased $11.4 million, or 117%, between the first half of 2009 and the same period in 2010, with the majority of this increase attributable to the improved segment results, decreased general and administrative expenses and decrease in depreciation and amortization expense as discussed below.

Segment Margin

The contribution of each of our segments to total Segment Margin in the three and six months ended June 30, 2010 and 2009 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Pipeline transportation	$11,437	$10,347	$21,836	$20,572
Refinery services	16,190	13,190	29,450	25,949
Supply and logistics	7,221	6,600	11,733	12,556
Industrial gases	3,001	2,869	5,495	5,892
Total Segment Margin	$37,849	$33,006	$68,514	$64,969

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	2010	2009	2010	2009
Mississippi-Bbls/day	23,493	24,159	23,789	24,758
Jay - Bbls/day	14,400	9,307	14,493	9,369
Texas - Bbls/day	27,902	25,069	23,602	27,435
Free State - Mcf/day	133,009	134,570	154,013	152,830

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$4,896	$3,997	$9,412	$7,950
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	6,263	6,376	12,951	13,120
Sales of crude oil pipeline loss allowance volumes	1,533	1,406	2,872	2,205
Non-income payments under direct financing leases	1,038	929	2,053	1,836
Other miscellaneous revenues	175	140	351	318
Revenues from natural gas tariffs and sales	558	537	1,497	1,270
Natural gas purchases	(492)	(470)	(1,357)	(1,124)
Pipeline operating costs, excluding non-cash charges for our equity-based compensation plans and other non-cash charges	(2,534)	(2,568)	(5,943)	(5,003)
Segment margin	$11,437	$10,347	$21,836	$20,572

Three Months Ended June 30, 2010 Compared with Three Months Ended June 30, 2009

Pipeline Segment Margin for the second quarter of 2010 increased $1.1 million. The primary components of this change related to the volumes on our crude oil pipelines and the tariffs and payments from direct financing leases related to those pipelines, which increased $1.0 million in total. Significant factors were as follows:

- Volumes transported on our Jay crude oil pipeline system increased 5,093 barrels per day. At the end of 2009, a producer connected to our Jay System restarted production from wells that were shut in during the majority of 2009 due to the decline in crude oil prices. Additionally, the Castleberry extension of our Jay System allowed us to access additional production in the area, increasing volumes on the Jay System between the periods.

- Volumes on the Texas System increased 2,833 barrels per day; however the increase had a relatively low impact on revenues. Approximately 80% of the volume on that system in the second quarter was shipped on a tariff of $0.31 per barrel.

- Volume fluctuations on the Mississippi System, where the incremental tariff rate is only $0.25 per barrel, are primarily a result of activities of crude oil producers. Volumes on this system declined by 666 barrels per day.

- Tariff rate increases of approximately 7.6% on our Jay and Mississippi pipelines went into effect July 1, 2009.

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Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009

Pipeline Segment Margin increased $1.3 million between the six month periods. The significant components of this change were as follows:

- Volumes on the Jay System increased 5,124 barrels per day due to restarted production from wells that had been shut in for most of 2009 as well as the addition of volumes we are able to access with the Castleberry extension to the Jay System. Volumes on the Texas and Mississippi Systems declined between the periods in large part to maintenance in the first quarter of 2010 on the Texas System.

- Tariff rate increases of approximately 7.6% on our Jay and Mississippi pipelines went into effect July 1, 2009. Segment Margin increased by approximately $0.5 million between the two periods as a result of these rate changes.

- An increase in revenues from sales of pipeline loss allowance volumes increased segment margin by $0.7 million related to the significant increase (an average of $27 per barrel) in crude oil prices which more than offset the decrease in pipeline loss allowance volumes of approximately 5,204 barrels.

- Pipeline operating costs increased $0.9 million largely due to pipeline integrity tests on a segment of our Texas System in the first quarter of 2010 that cost approximately $0.6 million.

Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Volumes sold:				
NaHS volumes (Dry short tons "DST")	38,307	20,908	71,414	47,137
NaOH (caustic soda) volumes (DST)	23,969	19,763	45,336	36,663
Total	62,276	40,671	116,750	83,800
Revenues (in thousands):				
NaHS revenues	$30,517	$20,846	$54,771	$52,100
NaOH (caustic soda) revenues	6,810	11,530	11,612	27,079
Other revenues	3,021	3,547	5,335	6,649
Total external segment revenues	$40,348	$35,923	$71,718	$85,828
Segment margin	$16,190	$13,190	$29,450	$25,949
Average index price for caustic soda per DST (1)	$340	$450	$304	$640
Raw material and processing costs as % of segment revenues	35 %	45 %	32 %	53 %
Delivery costs as a % of segment revenues	15 %	10 %	17 %	9 %

(1) Source: Harriman Chemsult Ltd.

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Three Months Ended June 30, 2010 Compared with Three Months Ended June 30, 2009

Refinery services Segment Margin for the second quarter of 2010 was $16.2 million, an increase of $3.0 million, or 23%, from the comparative period in 2009. The significant components of this fluctuation were as follows:

- An increase in NaHS sales volumes of 83%. Macroeconomic conditions in some of our markets have improved, increasing the demand for NaHS. In particular, we have experienced a noticeable increase in NaHS demand from some copper and molybdenum miners in South America as well as the western United States, and, to a lesser extent, industrial customers (primarily pulp and paper manufactures and leather tanners). The average sales price of NaHS declined by 20% because increases in some commodity components and contractual price inflators were more than offset by the declines in other areas. The pricing in the majority of our sales contracts for NaHS include an adjustment for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments can be applied varies by geographic region and supply point.

- An increase in caustic soda sales volumes of 21%. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. We are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties.

- Index prices for caustic soda averaged approximately $450 per DST in the second quarter of 2009. Market prices of caustic soda have decreased to an average of approximately $340 per DST during the second quarter of 2010. That volatility affects the revenues and costs related to our sulfur removal services (and, accordingly, our related NaHS sales activities) as well as our caustic soda sales activities. However, changes in caustic soda prices generally do not materially affect Segment Margin attributable to our sulfur processing services because we generally pass those costs through to our NaHS sales customers. The decline in caustic soda prices did, however, reduce our revenues from sales of caustic soda by 41% offsetting some of the increase in Segment Margin from additional sales volumes of NaHS.

- Higher delivery logistics costs. Although our logistics costs per unit increased only modestly, our logistics costs expressed as a percentage of revenues increased by 5% (to 15%) primarily because our sales price per unit, along with our cost per unit, dropped precipitously. Quantities delivered to customers also increased. Freight demand and fuel prices increased modestly in the 2010 period as economic conditions improved, increasing demand for transportation services and the increase in crude oil prices increased the cost of fuel used in transporting these products.

Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009

Segment margin for our refinery services increased $3.5 million for similar reasons to the quarterly comparison.

- NaHS volumes increased 51%, as a result of increased demand from mining companies and other industrial customers. The improvements in macroeconomic conditions in some of the markets in which these customers operate, particularly South America and the western United States, have increased their demand for NaHS. The related revenue increase was only 5% due to the effects of the pass-through of fluctuations in commodity benchmarks and transportation.

- Caustic soda sales volumes increased 24%, however revenues decreased 57% as the market prices for caustic soda decreased from an average of $640 per DST in the first six months of 2009 to an average of $304 per DST in the first six months of 2010.

- Delivery costs increased as freight demand and fuel prices increased in the 2010 period. Quantities delivered to customers also increased.

Supply and Logistics Segment

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

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Supply and logistics revenue	$400,861	$291,364	$820,960	$480,426
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(369,228)	(266,631)	(761,419)	(431,948)
Operating and segment general and administrative costs, excluding non-cash charges for stock-based compensation and other non-cash expenses	(24,412)	(18,133)	(47,808)	(35,922)
Segment margin	$7,221	$6,600	$11,733	$12,556
Volumes of crude oil and petroleum products - average barrels per day	50,383	47,941	53,799	45,257

Three Months Ended June 30, 2010 Compared with Three Months Ended June 30, 2009

The average market prices of crude oil and petroleum products increased by more than $18 per barrel, or approximately 31%, between the two quarterly periods; however that price volatility had a limited impact on our supply and logistics Segment Margin. More significant factors for us are discussed below.

The key factors affecting the two quarters were as follows:

- Increased opportunities to handle the heavy end petroleum products due to increased access to transportation services (including those of DG Marine) and storage facilities improved Segment Margin.

- Segment Margin from DG Marine's inland marine barge operations increased as four additional barges were in service for the entire 2010 second quarter. Construction was completed on the barges during the second quarter of 2009, and they were placed in service partway through that period.

- The narrowing of quality differentials and contango pricing beginning late in the fourth quarter of 2009 and extending through the second quarter of 2010 limited the contribution to Segment Margin from storing crude oil.

Our petroleum products activities involve handling volumes from the heavy end of the refined barrel. Despite decreased refinery activity in both periods due to economic conditions, our increased access to heavy products storage capacity leased from third parties and to barge transportation services through DG Marine resulted in an increase of approximately $0.9 million in the contribution of petroleum products activities to Segment Margin.

The inland marine transportation operations of DG Marine contributed $0.3 million more to Segment Margin in the second quarter of 2010 as compared to the second quarter of 2009. Although average day rates were slightly lower in the second quarter of 2010 than in the second quarter of 2009, the addition of four newly-constructed barges more than offset the effects of rate differences.

Beginning late in 2008 and throughout most of 2009, the crude oil market was in wide contango. When crude oil markets are in contango, oil prices for future deliveries are higher than for current deliveries, providing an opportunity for us to purchase crude oil at current market prices, re-sell it through futures contracts at future prices, and store it as inventory until delivery. In the second quarter of 2009, we took advantage of contango conditions, placing approximately 226,000 barrels of crude oil in storage throughout the quarter. In 2010, contango market conditions had narrowed such that crude oil sales prices were not sufficient to support the costs associated with storing inventory. Additionally, fluctuations in differentials between different grades of crude oil, which we refer to as quality differentials, reduced margins on our gathering activities. As a result, margins from crude oil gathering and marketing activities declined approximately $0.6 million.

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Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009

For the six month periods, the improvements in our heavy end petroleum products opportunities only partially offset the impacts of the narrowing in contango pricing and differentials in the crude oil markets. Segment Margin between the two periods declined $0.8 million. The key factors affecting the two six-month periods were as follows:

- Quality differentials and contango pricing narrowed beginning late in the fourth quarter of 2009 and extended through most of the second quarter of 2010 decreasing the contribution to Segment Margin of our crude oil activities by $2.7 million.

- Many of DG Marine's inland marine tows were under term charter agreements during part of the first six months of 2009. As those agreements expired in the late spring and summer of 2009, average charter rates declined for the remainder of 2009, as the tows were operated under spot contract arrangements. Although average charter rates at DG Marine's inland marine operations have improved in the first six months of 2010, the differences as compared to the first six months of 2009 resulted in a decline in Segment Margin of $0.5 million. Slightly offsetting the decline in average charter rates was the contribution to Segment Margin from four additional barges placed in service during the second quarter of 2009.

- Increased opportunities to handle the heavy end petroleum products due to increased access to transportation services (including those of DG Marine) and storage facilities in 2010 increased segment margin $2.3 million, partially offsetting the affects of the two factors above.

Industrial Gases Segment

Operating results from our industrial gases segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Revenues from CO2 marketing	$4,031	$3,791	$7,303	$7,520
CO2 transportation and other costs	(1,582)	(1,356)	(2,832)	(2,679)
Available cash generated by equity investees	552	434	1,024	1,051
Segment margin	$3,001	$2,869	$5,495	$5,892
Volumes per day:				
CO2 marketing - Mcf	74,724	70,621	67,847	70,229

Three Months Ended June 30, 2010 Compared with Three Months Ended June 30, 2009

Segment Margin from the industrial gases segment increased between the quarterly periods primarily due to an increase in volumes delivered to our customers. Volumes increased 6% between the two quarterly periods as customers increased purchases in response to improving economic conditions. The average sales price of CO2 was generally consistent between the quarters.

Our industrial gases segment experienced increased costs due to inflationary adjustments to the rates we are charged to transport CO2 to our customers. Average transportation rates increased by 9.0% over the average rates in the 2009 second quarter.

Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009

The decrease in segment margin between the two six-month periods was the result of a slight decrease in volumes delivered to our customers in combination with an increase in average transportation rates of 9%.

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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,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
General and administrative expenses not separately identified below	$5,175	$4,706	$10,037	$10,095
Expenses related to change in owner of our general partner	-	-	1,762	-
Bonus plan expense	1,306	779	2,306	1,634
Equity-based compensation plan expense	19	468	666	832
Non-cash compensation expense related to management team	301	2,353	(1,676)	4,499
Total general and administrative expenses	$6,801	$8,306	$13,095	$17,060

Comparing the three-month and six-month periods, the primary factor driving the decrease in general and administrative expenses related to the change in non-cash compensation expense related to our management team. On December 31, 2008, our general partner and members of our management team entered into an equity-based compensation arrangement whereby our management team could earn an interest in distributions attributable to our incentive distribution rights owned by our general partner. While the former owner of our general partner was responsible for the cash cost of this compensation with our management team, we recorded the expense of those arrangements with an offsetting non-cash capital contribution by our general partner. On February 5, 2010, as a result of the sale of our general partner, that equity-based compensation arrangement was settled. In the first quarter of 2010, we recorded a credit of $2.0 million to general and administrative expense related to the difference in the ultimate settlement value of $14.9 million and the amounts that were previously charged to expense related to this arrangement. In the three and six month periods of 2009, we recorded expenses of $2.4 million and $4.5 million, respectively, related to these non-cash compensation arrangements with our management team. See Note 9 to our unaudited condensed consolidated financial statements.

Partially offsetting the reduction from those compensation arrangements between the six-month periods were $1.8 million of expenses we incurred related to the sale of our general partner, including costs related to a public offering of the common units initially retained by the former owner of our general partner and severance arrangements for an executive officer. Additionally, affecting Available Cash before Reserves, but not net income, was an increase of approximately $0.7 million in exercises of stock appreciation rights.

Depreciation and amortization expense. Depreciation and amortization expense decreased $2.5 million and $4.5 million between the three and six month periods, respectively, as a result of the lower amortization expense recognized on intangible assets. We amortize our intangible assets over the period during which we expect them to contribute to our future cash flows. The amortization we record on those assets is greater in the initial years following their acquisition because the value of our intangible assets such as customer relationships and trade names are generally more valuable in the first years after an acquisition. Accordingly, the amount of amortization we have recorded has declined since we acquired those assets in 2007.

Interest expense, net.

Interest expense, net was as follows:

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Interest expense, including commitment fees, excluding DG Marine	$2,074	$1,966	$3,998	$3,781
Amortization of facility fees, excluding DG Marine facility	165	165	328	328
Write-off of facility fees, excluding DG Marine	402	-	402	-
Interest expense and commitment fees - DG Marine	1,143	1,281	2,274	2,445
Capitalized interest	(9)	(23)	(9)	(109)
Interest income	(15)	(16)	(29)	(37)
Net interest expense	$3,760	$3,373	$6,964	$6,408

Our interest expense increased as the average interest rate for borrowed funds increased slightly quarter to quarter offsetting the impact of the $6.6 million decrease in our average debt balance over the same periods. For the six-month periods, our average outstanding debt balance was $1.6 million higher in 2010 than 2009.

Income tax expense. Income tax expense relates to corporate-level income tax accruals (accrued by the Partnership) and Texas Margin Tax on our operations in Texas. As the majority of our operations are not conducted by corporations, income tax expense is not expected to be significant.

Liquidity and Capital Resources

Capital Resources/Sources of Cash

Recent market trends have indicated improvements in bank lending capacity and long-term interest rates from the situation in early 2009. 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 $6.0 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.

We continue to pursue a growth strategy that requires significant capital. We expect our short-term and long-term capital resources to include equity and debt offerings (public and private), revolving and term credit facilities 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.

On June 29, 2010, we restructured our credit facility – which we entered into in November 2006 and which was to mature in November 2011 – to reflect and better accommodate our larger and more diversified operations and resulting credit metrics. Our restructured credit facility is a $525 million senior secured revolving credit facility maturing on June 30, 2015. It includes an accordion feature whereby the total credit available can be increased up to $650 million for acquisitions or internal growth projects, with lender approval. Among other modifications, our credit facility also includes a $75 million inventory sublimit tranche. This inventory tranche is designed to allow us to more efficiently finance crude oil and petroleum products inventory in the normal course of our operations, by allowing us to exclude the amount of inventory loans from our total outstanding indebtedness for purposes of determining our applicable interest rate. Additionally, our restructured credit facility does not include a "borrowing base" limitation except with respect to our inventory loans. Eleven lenders participate in our credit facility, and we do not anticipate any of them being unable to satisfy their obligations under the credit facility. Additional information on our restructured credit facility is included in Note 5 to the unaudited condensed consolidated financial statements.

While our new credit facility provides additional flexibility and committed borrowing capacity, our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital, to utilize our 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.

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We continue to monitor the credit markets and the economic outlook to determine the extent of the impact on our business environment. While we have experienced increases in demand for NaHS in 2010 resulting primarily from increased mining activities associated with increases in commodity prices for copper and molybdenum, we continue to experience lower demand for crude oil and petroleum products, primarily due to low utilization rates at refineries. We continue to adjust to the effects of these macroeconomic factors in our operating levels and financial decisions.

On July 29, 2010, in connection with our acquisition of the 51% interest of DG Maine that we did not own, we paid off DG Marine's stand-alone credit facility, which had an outstanding principal balance of $44.4 million, with proceeds from our credit agreement. See Note 14 to our unaudited condensed consolidated financial statements and our Current Report on Form 8-K filed August 3, 2010.

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.

Debt and Other Financing Activities. Our sources of cash are primarily from funds from operations and our credit facilities. Our net borrowings under our credit facility and the DG Marine credit facility totaled $38 million during the first half of 2010, which primarily related to increases in petroleum products inventory levels to take advantage of blending and storage opportunities. The remainder of these borrowings related primarily to the investment in fixed and intangible assets and the payment of liabilities accrued at the 2009 year end for such items as annual bonus payments and property tax obligations. We paid distributions totaling $33.8 million to our limited partners and our general partner during the first half of 2010. For a more detailed analysis of our recent distributions, see Note 6 to our unaudited condensed consolidated financial statements.

Investing. We utilized cash flows for capital expenditures. The most significant investing activities in the first half of 2010 were expenditures related to our project to upgrade our information technology systems discussed below.

Capital Expenditures, and Business and Asset Acquisitions

A summary of our expenditures for fixed assets and other asset acquisitions in the first half of 2010 and 2009 is as follows:

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	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in thousands)	
Capital expenditures for property, plant and equipment:		
Maintenance capital expenditures:		
Pipeline transportation assets	134	750
Supply and logistics assets	574	720
Refinery services assets	815	544
Administrative and other assets	20	408
Total maintenance capital expenditures	1,543	2,422
Growth capital expenditures:		
Pipeline transportation assets	123	1,708
Supply and logistics assets	433	17,869
Refinery services assets	-	1,438
Information technology systems upgrade project	4,492	-
Total growth capital expenditures	5,048	21,015
Total	6,591	23,437
Capital expenditures for asset purchases:		
Acquisition of intangible assets	-	2,500
Total asset purchases	-	2,500
Capital expenditures attributable to unconsolidated affiliates	-	21
Total	-	21
Total capital expenditures	$ 6,591	$ 25,958

During the remainder of 2010, we expect to expend approximately $2.0 million for maintenance capital projects in progress or planned. We also plan to spend approximately an additional $6 million in capital costs to integrate and upgrade our information technology systems to be positioned for further growth, which we will fund with borrowings under our credit facility.

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

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 distributable 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 costs 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.

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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 is the quantitative metric used by many in the investment community with respect to publicly-traded partnerships.

The reconciliation of Available Cash before Reserves (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) is as follows:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
	(in thousands)	
Cash flows from operating activities	$ (2,577)	$ 15,909
Adjustments to reconcile operating cash flows to Available Cash:		
Maintenance capital expenditures	(918)	(1,474)
Proceeds from sales of certain assets	857	52
Amortization and write-off of credit facility issuance fees	(814)	(481)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	132	34
Earnings of DG Marine in excess of distributable cash	(1,481)	(904)
Other items affecting available cash	584	443
Net effect of changes in operating accounts not included in calculation of Available Cash	30,292	8,629
Available Cash before Reserves	$ 26,075	$ 22,208

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, 2009.

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, 2009, nor do we have any debt or equity triggers based upon our unit or commodity prices.

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, 2009 and any other risk factors contained in our Current Reports on Form 8-K that we may file from time to time with the SEC. 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 2009 Annual Report on Form 10-K. There has been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures provided therein. Also, see Note 11 to our Unaudited Condensed Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

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Item 4. Controls and Procedures

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

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

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, 2009. 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, 2009. On August 3, 2010, we filed a Current Report on Form 8-K that covered several items, including our acquisition of the remaining interest in DG Marine. That Current Report on Form 8-K included some additional risk factors. There have been no material changes to the risk factors since the filing of such Form 10-K and/or that Current Report on Form 8-K.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. [Removed and Reserved]

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	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 10.2 to Form 8-K dated March 5, 2010)
3.5	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)

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3.6		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)
3.7		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)
3.8		Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 7, 2009)
3.9		Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated February 5, 2010 (incorporated by reference to Exhibit 3.1 to Form 8-K dated February 11, 2010)
3.10	*	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated June 11, 2010
3.11	*	Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated July 28, 2010
4.1		Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2007)
10.1		Second Amended and Restated Credit Agreement, dated as of June 29, 2010, among Genesis as borrower, BNP Paribas as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 2, 2010)
10.2		Contribution and Sale Agreement, dated July 28, 2010, by and between TD Marine, LLC and Genesis (incorporated by reference to Exhibit 10.1 to Form 8-K dated August 3, 2010)
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

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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 6, 2010	By:	/s/ Robert V. Deere
		Robert V. Deere
		Chief Financial Officer

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